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

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ABSTRACT

Among the many challenges faced in implementing technology to reduce CO_2 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 for the years 2020 and 2030. 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 CO_2 Greenhouse Gas (GHG) in the atmosphere of 450 ppm. 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 IEA[1] 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 CO_2 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 13 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:

i.) 3 regions: Europe (EUR), North America (NAM), South East Asia (excluding China & India)

ii.) 2 technologies: oxy-combustion (Oxy), post combustion capture (PCC)

iii.) 3 types of fuel: Hardcoal, Lignite (raw and dried for EUR only) and Gas,

iv.) 2 phases: early commercial in ~2015-2020, mature market in ~2030

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 2015, then performance improvements are considered (e.g. double re-heat steam turbine after 2015).

		EUR			NAM	SEA
Fuel type		Bituminous coal	Raw Lignite	Dried Lignite	PRB coal	Bituminous
Fuel heating value	KJ/Kg LHV	24 930	10 278	21 283	19 000	25 170
Carbon content	mass%	65%	30.6%	57.1%	51.7%	62.1%
Fuel price 2010	Euro/t	63	23.5	23.5	24	62
	Euro/GJ	2.52	2.29	2.06	1.26	2.45
Cycle argt 2020/30	bar/°C/°C	300b/600/620°C	272b/600/605°C	300b/600/620°C	300b/600/620°C	300b/600/620°C
Cooling type	°C	13°C - Direct C	18°C - CT	18°C - CT	19°C - CT	28°C - 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 %	43/44.7/45 %
EPC 2015/20/30	€/KW net	1634/1745/1745	1780/-/-	1895/2017/2017	1530/1634/1634	932/945/945

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

Plant operating time is set at 7446 hours per annum, construction time: 4 years for Hardcoal, 5 years for Lignite. Base year for cost is 2010. EPC indicated costs are market price.

Years 2015-30 in the presented graphs are defined as year of order, Notice to Proceed (NTP). Scope variations throughout the 2010-2030 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 equipped 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 2010	Euro/GJ	5.16	4.8	6.5
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	580/565/550	618/602/586	464/452/440

Table 2 : main market assumptions for combined-cycle

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 2015-30 period, including:

i.) a performance improvement for the reference and the CCS incremental capture plants evaluated separately for each sub-systems (e.g. the ASU consumption was selected at 180 kWh/tO_2 in 2015 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)

ii.) a correction on the resulting Capex/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 (10% in SEA) and 15% for gas CCPP

Figure 1 presents the assumptions considered for the on-shore and off-shore transport and storage (T&S) 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.

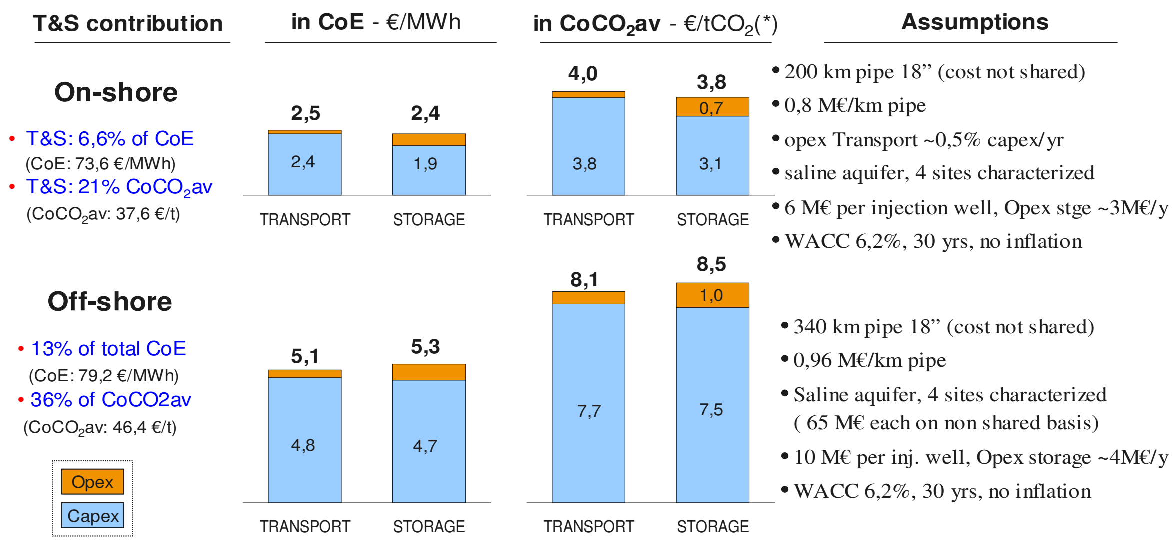


Figure 1: base case assumptions for transport and storage

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 (2010 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):	4,00% / 4,5% / 8,2%
• Cost of Equity (real rate w/o inflation):	9,76% / 9,5% / 11%
• Debt fraction:	50% / 55% / 50%
• Tax rate:	35% / 39% / 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) for Hardcoal CCS cases with PCC advanced amine and Oxy are presented by region in the figure 2.

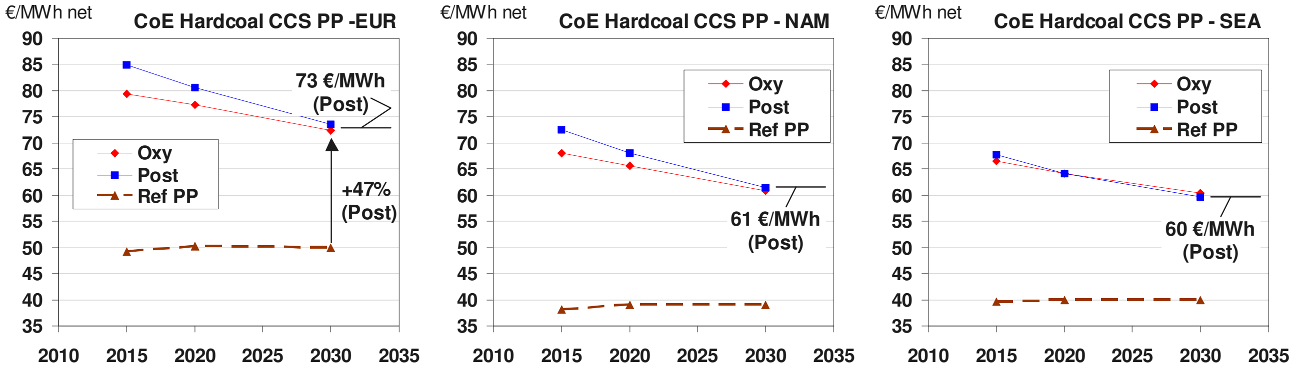


Figure 2: Cost of electricity for Hardcoal power plant equipped with CCS

The Increase in COE resulting from implementation of CCS in 2030 could be cut from 60-70% in 2015 down to about 45% in 2030 in EUR (COE 73 €/MWh). In NAM and SEA regions, the COE of the plant equipped with CCS are ~17% lower than in Europe in 2030, reaching 61 €/MWh in NAM because of a cheaper coal fuel and 60 €/MWh in SEA because of lower Capex/Opex costs. The resulting Cost of CO_2 avoided could then target ~30 €/t in NAM and SEA and 35 €/t in EUR in 2030 (no CO_2 price being accounted for).

A specific energy penalty of 15-16 % can be realistically targeted in 2030 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 ~1 to 3% higher in SEA, where Oxy is a slightly more penalized by the higher cooling temperature.

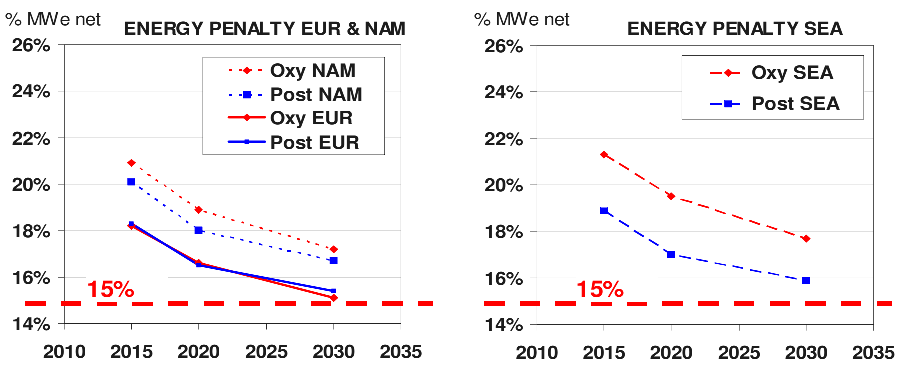


Figure 3: Energy penalty due to CO_2 capture systems, by region

The impact on performance due to higher cooling water temperature in SEA versus NAM is mitigated by better coal characteristics (heating value and carbon content), however fuel cost is much higher in SEA than in NAM, which offsets the better performance and 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 61% to 45% for Oxy over the period 2015-30 and from 71% to 47% 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.

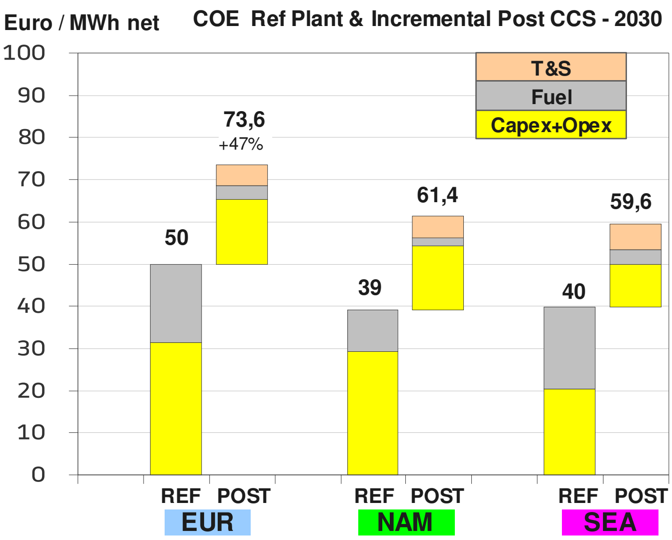


Figure 4: Post: Fuel Capex & Opex contribution in the COE

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.

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 5,3/4,9 €/MWh in EUR to 6,6/6,1 €/MWh in SEA in 2015/30 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.

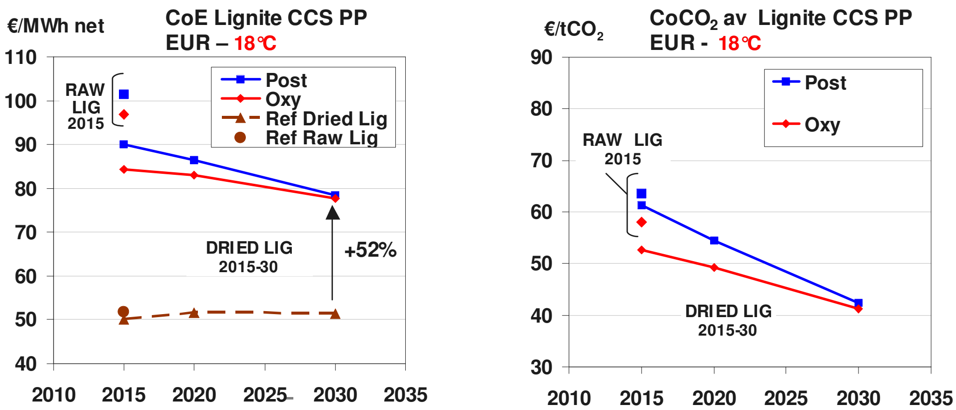
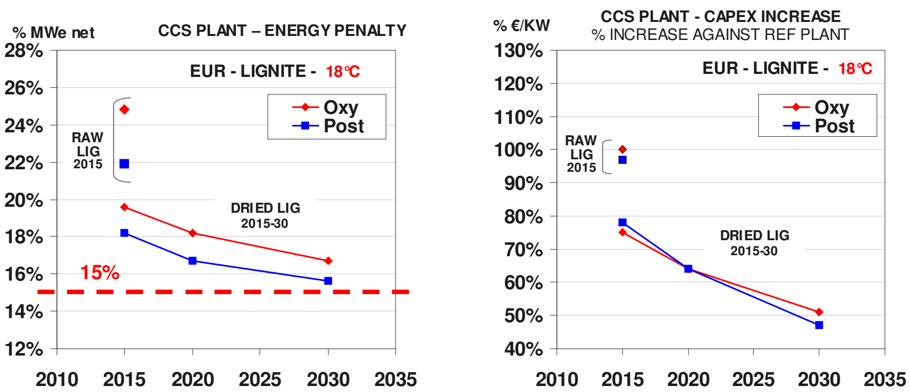


Figure 5: CoE and $CoCO_2$ avoided for Lignite power plant equipped with CCS

Raw lignite is presented in 2015 only for comparison with dried lignite. After 2015 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 2030 could be cut from 70-80% in 2015 down to about 52% in 2030 in Europe (COE 78 €/MWh). The Cost of CO_2 avoided could target approximately 40 €/t in 2030 (no CO_2 price being accounted for). An energy penalty of 15-16 % can be targeted in 2030 for the CCS technologies in Europe.



The Capex increase against reference plant drops from around 75% in 2015 down to around 50% in 2030.

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 2030 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 2030).

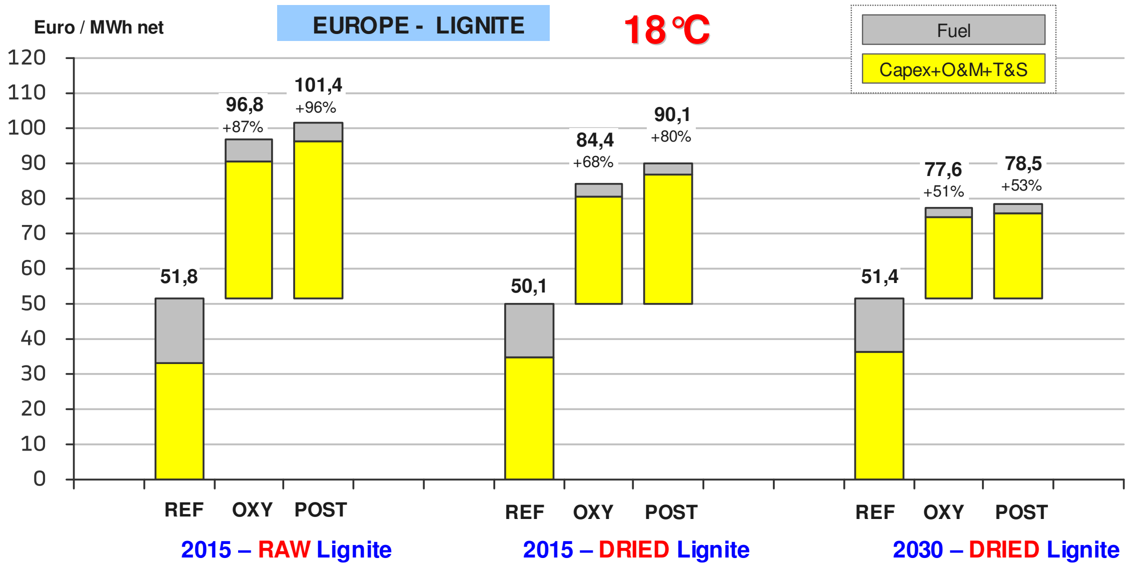


Figure 7: Fuel cost, Capex and Opex contribution in the CoE

Raw Lignite is heavily penalized because of a lower reference plant efficiency, a higher specific CO_2 emissions per net MWh both leading to higher CCS Capex, Opex and T&S costs.

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.

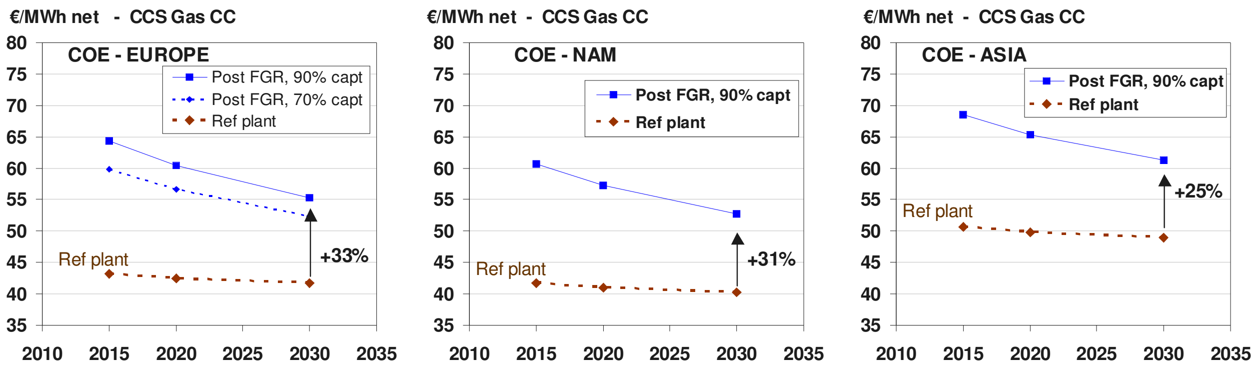


Figure 8 CoE of gas combined cycle plant equipped with CCS and flue gas recirculation

For the reference case at 90% capture, the Increase in Cost of Electricity due to CCS in 2030 could be cut from 45-50% to about 30% in Europe and NAM (COE 55/53 €/MWh), and 25% in SEA. The reference plant and the CCS plants were calculated at same thermal gross assuming no change in the gas turbine design (resulting in lower CCS net power output).

A 70% capture case (design point and not operating point) reduces the total COE by 6% (52 €/MWh instead of 55). Without flue gas recirculation, the COE are slightly higher, +5% should be added on the 33%, 31% and 25% indicated in figure 8.

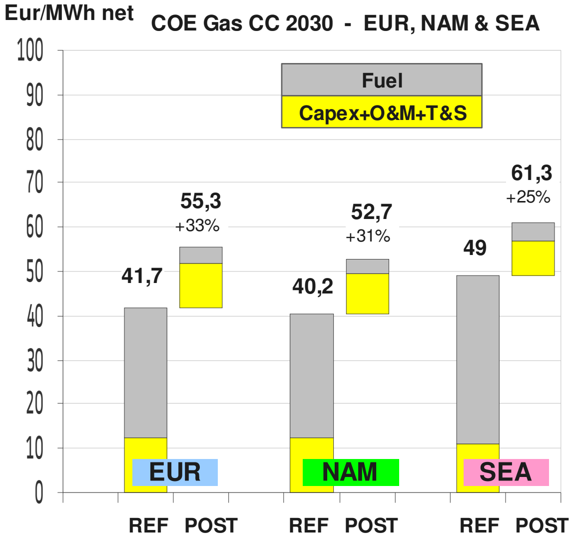


Figure 9: Gas Fuel contribution in the CoE

The Cost of CO_2 avoided can target ~45 €/t in 2030 with FGR. Without FGR, the cost of CO_2 avoided increases by ~16% to 52 €/t.

A 10 % energy penalty target can be reached in 2030 for the Post combustion CCS technology.

The Capex increase for CCS in % of the reference plant reduces from 115% to 70% in Europe, and from 90-95% to 55% in NAM and SEA throughout the 2015-30 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 SEA region on figure 9 gives an illustration of this: the COE is higher than in the other regions because of the high gas price considered (6,49 €/GJ) which offsets the lower Capex in the region.

The Impact of T&S on COE ranges from 1,9 (NAM-2030) to 2,5 (SEA-2015) €/MWh net depending on year and environmental conditions. The corresponding costs in €/tCO_2 are respectively to 6,6 to 8,6 €/tCO_2 avoided

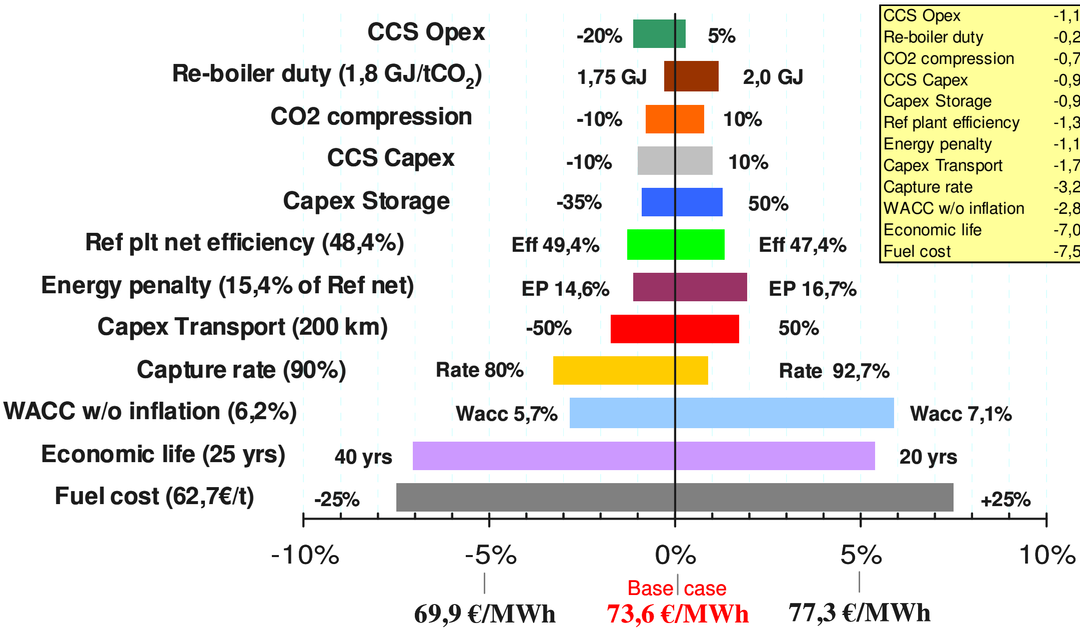
6 Main results – Sensitivity analysis

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 2030 (with onshore T&S). A range is indicated for each parameter around the base case value (ie: 1,75-2,0 GJ for re-boiler duty around the 1,8 GJ/tCO_2 base case value).



CCS Opex	-1,10%	0,28%
Re-boiler duty	-0,26%	1,16%
CO2 compression	-0,76%	0,77%
CCS Capex	-0,99%	0,99%
Capex Storage	-0,91%	1,30%
Ref plant efficiency	-1,30%	1,34%
Energy penalty	-1,10%	1,94%
Capex Transport	-1,70%	1,70%
Capture rate	-3,29%	0,90%
WACC w/o inflation	-2,81%	5,89%
Economic life	-7,05%	5,41%
Fuel cost	-7,51%	7,51%

Figure 10: Sensitivity on CoE base case 2030 (Europe, PCC advanced amine , on-shore T&S, no CO2

Each of the following economic parameters: Fuel cost, Economic life, WACC, impacts the COE by +/-6%, much more than CCS Perf/Capex/Opex parameters, however this impact is not fully attributable to the CCS additionality and an important share occurs anyway in the reference plant.

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.

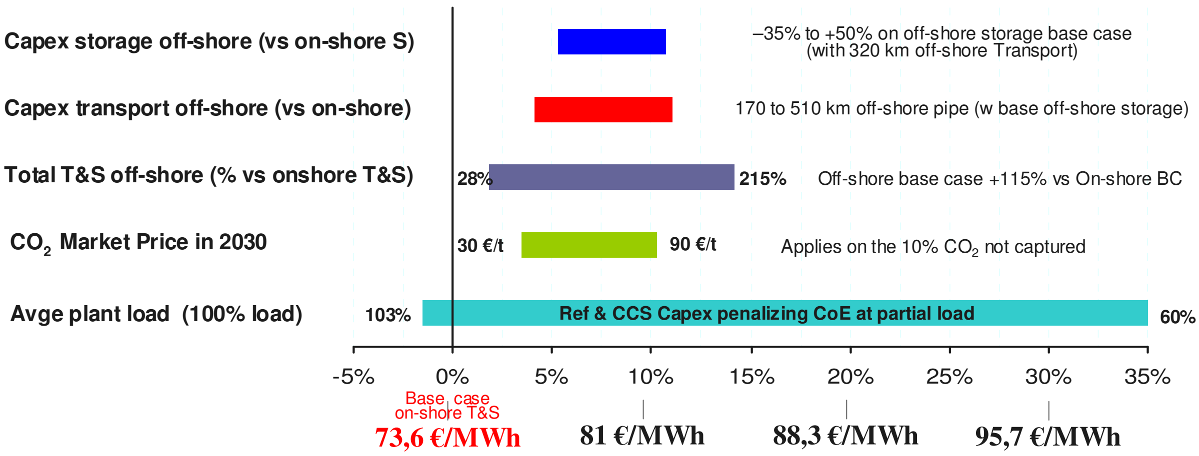


Figure 11: Sensitivity on CoE base case 2030

The impact on COE of T&S offshore base case versus onshore base case is +7,6% (equivalent +115% variation on T&S onshore costs).

The impact on COE of a 70 €/t CO_2 price in 2030 versus no CO_2 price is +8%. The impact of an average plant load at 60% instead of 100% is +35% 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 the 35% is attributable to CCS.

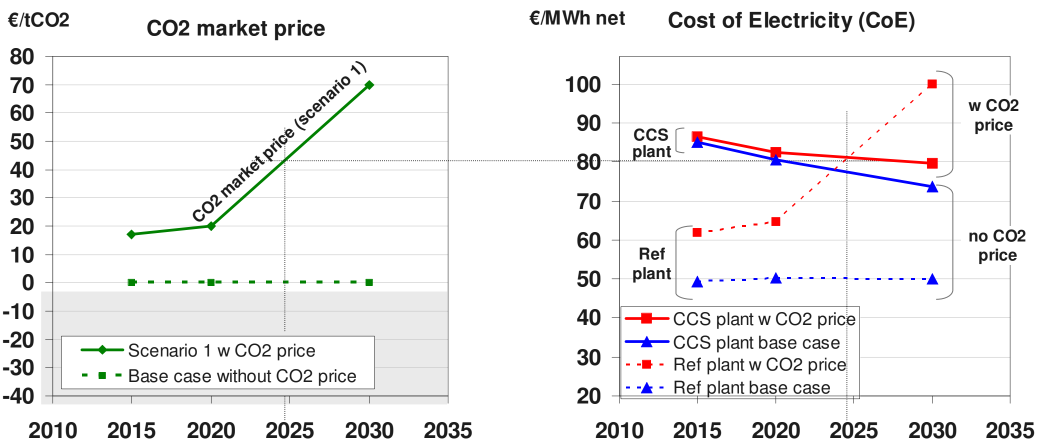


Figure 12: CO_2 price impact on reference and CCS plants for Hardcoal with Post AAP - Europe

Under the CO_2 market price scenario presented in figure 12, in 2025, for a CO_2 price of 43,2 €/tCO_2, we have the same COE for reference and CCS plants at 81€/MWh. In 2030, with a CO_2 price assumed at 70 €/t, the COE for the reference plant would be 100 €/MWh and for the CCS plant 79,5 €/MWh, increases of +100% and 8% 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 2030 of around –20% to +40% for PCC amine and Oxy.

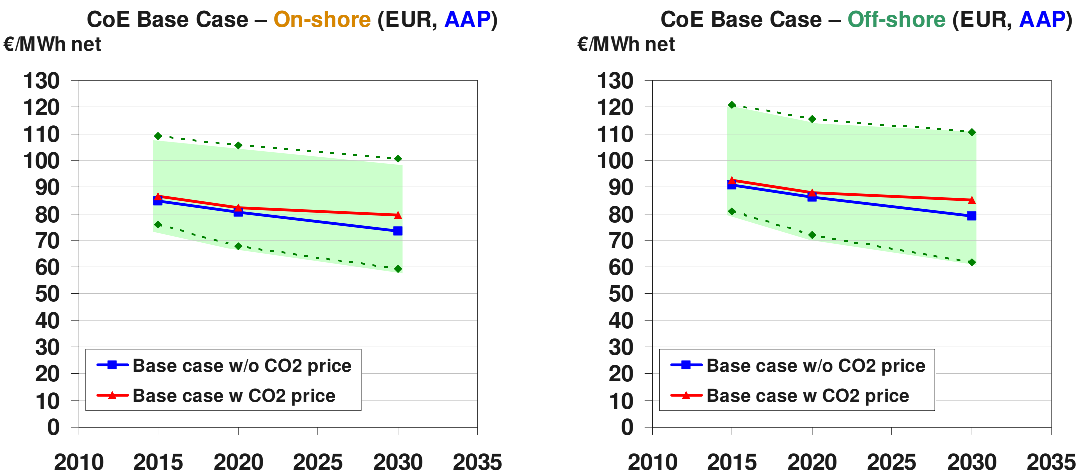


Figure 13: Final range for Hard coal CCS plant with Post AAP - Europe 2030

(note: consolidated upper range includes conservatively all parameters and CO2 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 (72,4 €/MWh)
Energy penalty % net ref PP	15,1%	15,9% (+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	112	101 (-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)	711 (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 2030, 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 2030 (onshore T&S).

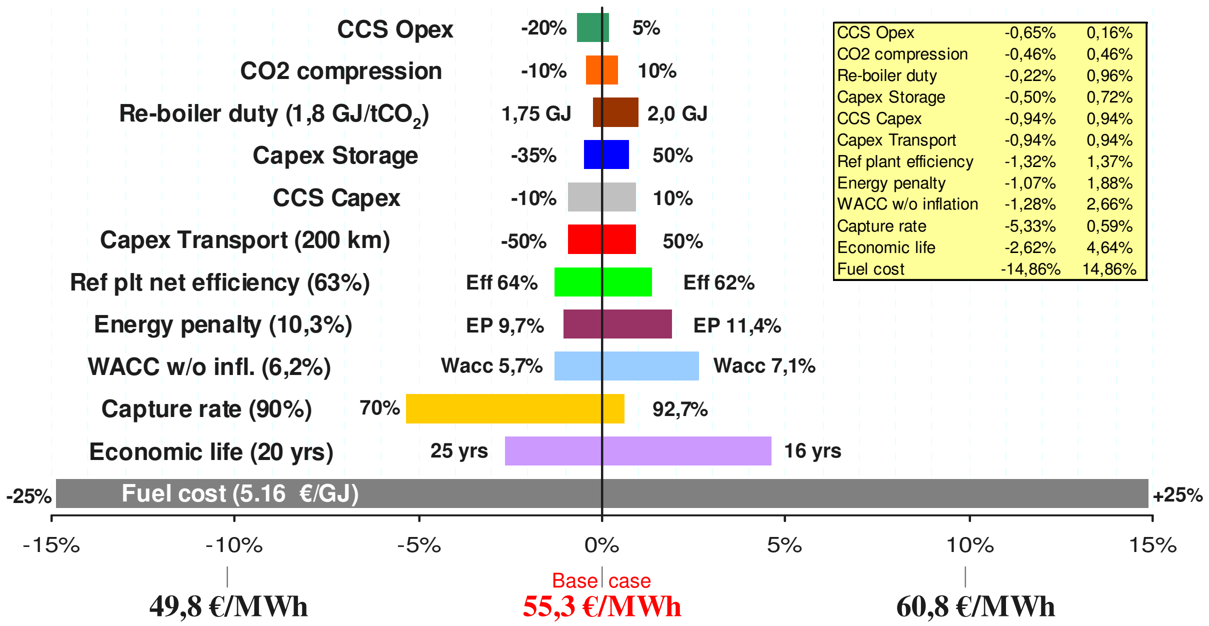


Figure 14: Sensitivity on CoE Gas CC CCS plant, base case 2030 (Europe, PCC amine, on-shore T&S, no CO_2 price)

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

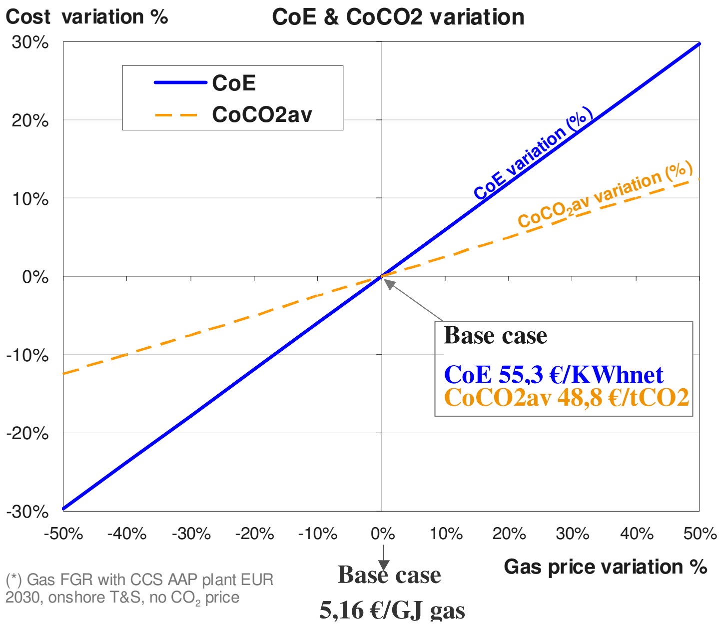


Figure 15: CoE CCS gas CC plant with FGR - Sensitivity on gas price

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.

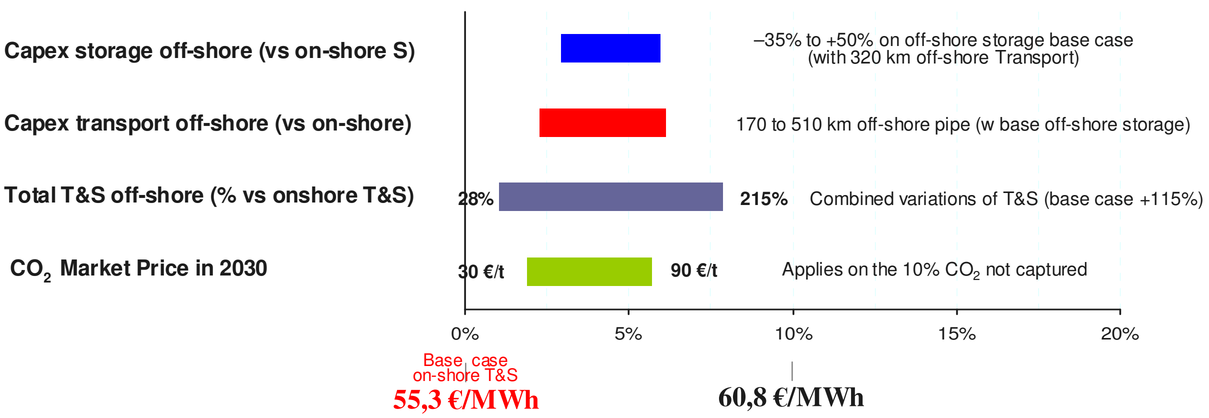


Figure 16: Sensitivity on CoE Gas CC CCS plant, base case 2030

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

Figure 17 shows that in ~2026, for a CO_2 price of around 54 €/tCO_2, we have the same COE for reference and CCS plants at ~59 €/MWh. In 2030, with a CO_2 price assumed at 70 €/t, the impact is +53% on the reference plant COE and +4,4% on the CCS plant COE.

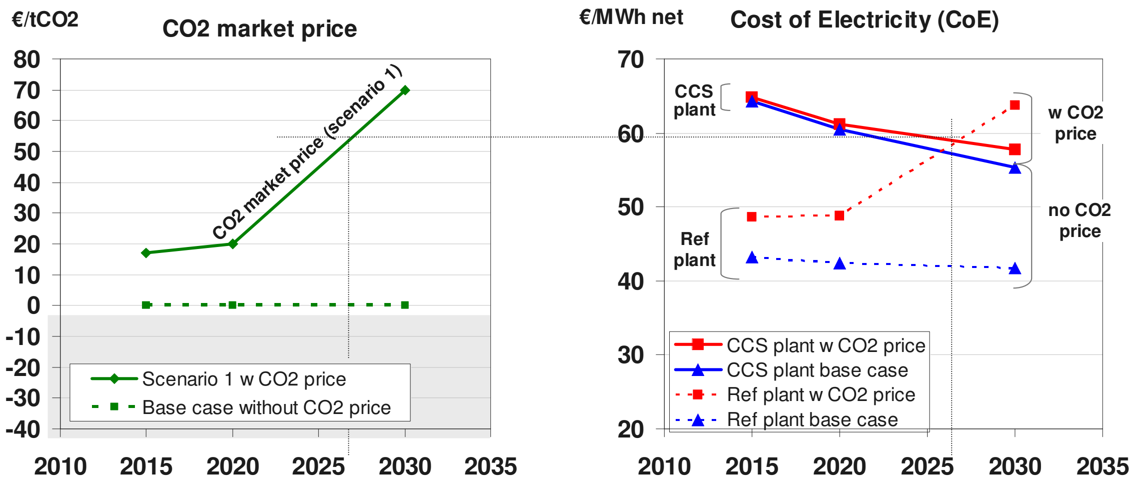


Figure 17: CO2 price impact on reference and CCS plants for gas CC with Post amine - Europe

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 2030 of around –35% to +45% 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 impact in 2030, 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, implimenting 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 capture 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 subtantially increased if the plant is already amortised and if a plant life extension (of ~15 years for example) could be implimented at a limited cost.

Typically, units in operation for 20 to 25 years with net efficiency of ~39% or more could be addressed from 2017/18, 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. after 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 2011 - 2016 period. Even when considering the very conservative range of variation assumed in our study, **CCS is competitive, starting in 2015, 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.

The indicated values for CCS plants in the bar chart are for Post amine and include a CO_2 price of 18 €/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.

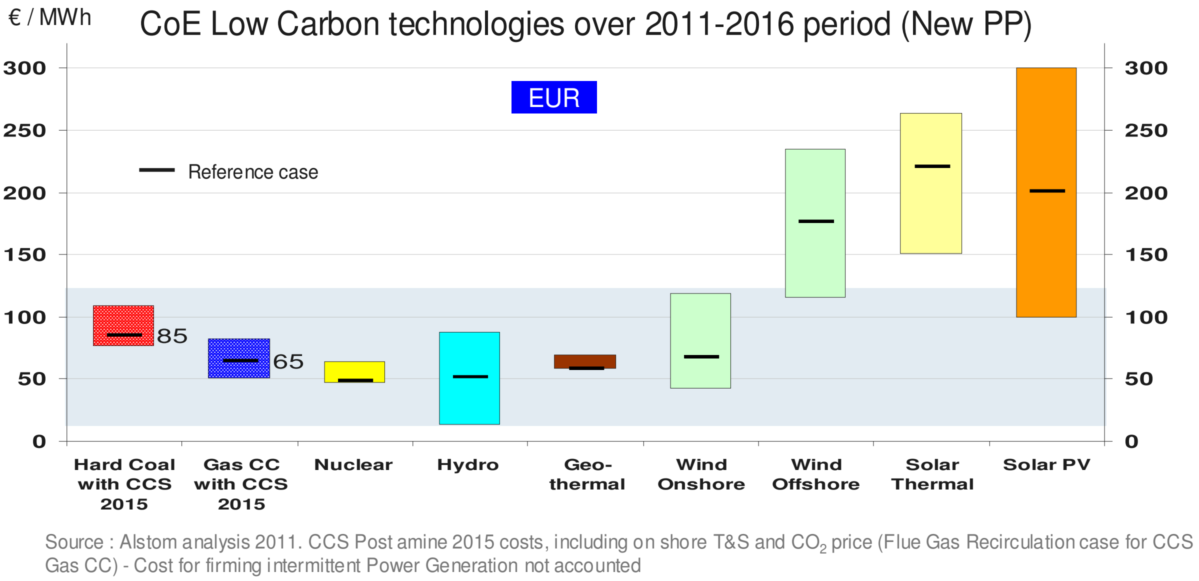


Figure 18: CoE of low carbon technologies – Europe 2015

The COE with CCS can be 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 2030, the cost of CO_2 avoided, including transport and storage is expected to reach levels below 35 €/t on coal and 45 €/t on gas (European case, with flue gas recirculation).

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 65 and 85 €/MWh for steam plants, depending on fuels and regions, the first large scale CCS units, to be ordered starting 2015, 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 70 €/MWh along with a CO_2 avoided cost below 40 €/t is realistically expected in 2030 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 2015, when applying CCS on both fuels, with COE varying between 60 and 70 €/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 in the 2020's and, consistent with the EU's longer term emission reduction goals, certainly by 2030.

- 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. At the very least it needs to ensure that all new coal and gas plants are built CCS-ready - and to keep alive the expectation of future mandation of CCS.

- Clear regulations on storage and long-term liabilities should be set as soon as possible. The EU Directive on CO_2 storage will be in force from 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