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Can CCS save the coal fired power plants – European perspective

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CAN CCS SAVE THE COAL FIRED POWER PLANTS – EUROPEAN PERSPECTIVE[*+]

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ABSTRACT

The purpose of this paper is to evaluate the carbon dioxide (CO2) emission costs of a coal fired independent power producer (IPP) operating in the European Union (EU). To achieve its CO2 emission obligations IPP has to choose between purchasing emission unit allowances (EUA) through EU Emission Trading Scheme and installing CO2 capture and storage system (CCS). Since there are significant differences and inconsistencies, in the various studies, our goal is to clearly identify the key drivers behind CCS costs and analyse the technical and economic viability of coal fired IPPs. An important question tackled in this paper is: what is the price of EUA of carbon dioxide that makes the IPP with CCS technology competitive in the current market. In this paper, we expand the existing equations for the calculating cost metrics by directly accounting for the chemical properties of the feedstock. Furthermore, instead of using a deterministic or a scenario-based approach we apply a parametric estimation of relevant variables. Our Monte Carlo simulations show that, under the current regime of electricity and

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EUA prices, an EU based, coal fired IPP is, at best, only marginally profitable. On the other hand, an identical IPP with CCS technology is completely unviable.

Keywords: Emission costs methods, Coal fired independent power producer, Carbon capture and storage, Emission unit allowances, Carbon sequestration energy requirements, Comparative power plant economics

1. Introduction

The EU has set very ambitious plans for drastically decreasing its output of greenhouse gases and is currently the leader in the decarbonised energy generation. In order to achieve the EU emission reduction goals in an economically sound manner (40% by 2030 and 80% by 2050, as per the EU 2050 Low-carbon Economy Roadmap **(EC, 2011**)) carbon capture and storage system (CCS) has been identified as one of the key components.

In the early beginning of the CCS US, Australia, Canada, and the EU have taken a leading role in the development of legal and regulatory framework to support the development of this technology **(Global CCS Institute, 2013)**. While significant progress has been made in the US, Australia, and Canada during the last six years, there has been no new, large-scale injection in Europe **(ZEP, 2014)**. As of the end of 2014, 13 large-sale CCS projects are in operation worldwide, two of which are in Europe (with offshore storage in Norway) (**Directorate-General for Climate Action, 2014**). Four other projects are in the planning stage in the EU and the most advanced is the ROAD project in the Netherlands (**ZEP, 2014**). The other three projects are in the UK, more specifically in Peterhead, White Rose and Don Valley, have advanced into front end engineering design and their earliest start is planned in 2017. The number of operational CCS installations has been much less than expected when the European Directive 2009/31/EC on the geological storage of CO_2 "CCS Directive" was passed. A number of projects have been proposed, with some being approved for European Commission support, but most of these have stopped or are in significant difficulties. Exceptions are the UK project White Rose (supported under the New Entrant Reserve (NER) 300 programme), Don Valley (with EEPR support) and Peterhead, and the Dutch ROAD project (with EEPR support) (**ZEP, 2014**). The view among stakeholders is that this lack of progress was driven by the lack of a commercial case for CCS, largely because of the global economic downturn and low carbon prices (via the European Union Emissions Trading System (EU-ETS)).

Although lacking practical implementation EU has put in place a number of successful policies designed to increase CCS research and development projects. As a result, looking just from the R&D perspective, EU stands al pari with the other leading nations. Since the challenge for CCS is not technical feasibility but enabling and supporting a feasible business model, without a successful implementation of larger demonstration projects, EU will continue to lag behind the early movers, which seriously reduces the prospects of commercializing and exporting CCS related technologies and know-how.

Lignite and hard coal make up for more than 80% of EU fossil reserves (**Eurocoal, 2014**). With the lack of domestic oil and insufficient amounts of gas, coal fired power plants will continue to play a major role in the EU energy mix as they provide an affordable and reliable source of primary feedstock. In light of the European reality CCS is the only proven technology enabling EU countries to continue exploiting domestic coal while greatly reducing negative impact on the environment. At the current technological level CCS is estimated to contribute to a reduction of at least 4% of the EU's greenhouse gas commitment effort by 2030 (**ZEP, 2013**). Approximately 75% of that amount is expected to come from the power generation sector (**ZEP, 2015**). A further benefit to using domestic coal is limiting dependence on imported energy and obtaining the diversity of supply. Since there is a large number of coal-fired plants in EU, retrofitting the existing ones with CCS will allow them to continue operating in a cleaner way.

In the future, the CCS will serve as one of the lifelines for the fossil-fuel plants and by keeping them operational it will continue to provide the power production flexibility from fossil-fuels and grid stability to electricity grids. By helping to provide a cleaner flexible back-up capacity, CCS can contribute to the energy system stability and security by diversifying the energy supply mix. Volatile energy output from renewable sources and their preferential access to the electricity grids seriously affects grid stability and thus the security of the whole system. Given the current technology, the state of European power grid system, and huge costs associated with building new power generating capacities and smart grids, conventional power generation is, now, the only part of the system that can ensure reliable and flexible electricity supply in the next decade. In this regard, CCS can be viewed as a means to bridging a gap between conventional power supply and decarbonised renewable power generation. By ensuring the stability and flexibility of the system through traditional power generation, CCS can allow a higher percentage of renewable generating capacity without endangering the system. CCS is an interim solution since its main goal in the EU is to provide the necessary time to develop and implement sustainable carbonless technologies, expected around 2050 (**ZEP, 2013, 2014**).

Another proclaimed benefit of CCS is that, where accessible, captured CO_2 does not only have to be deposited in appropriate geological formations, but also can be used in enhanced hydrocarbons recovery (EHR) from abandoned or declining oil and gas fields. Similarly, injected CO_2 can be used to free gas from storage reservoirs that would otherwise be used solely to maintain reservoir pressure. The benefits from this approach can be twofold. First, by using the CO_2 in EHR the cost of CCS transport and storage can be minimized or even negative. Second, reviving old oil and gas fields can increase EU energy security through increased domestic production.

From all of the above stated positive aspects of the CCS, it can be concluded that it represents a viable interim solution in a drive to decrease the carbon footprint of the European energy sector. Furthermore, it offers a few interesting options regarding the further proliferation of renewables, system stability and EHR projects. Normally there are several negative aspects that hider the implementation of CCS projects. The key challenges facing the implementation of CCS include technical, environmental, financial and regulatory issues. Among these, financial issues seem to represent a very serious obstacle. Besides the higher investment cost of building the CCS power plant, costs related to transport and storage there is also a technical/financial challenge related to high energy consumption associated with CO_2 capture and the energy penalty associated with the addition of CCS system to power plants.

The goal of this paper is to evaluate and compare the financial viability of a coal-fired power plants operating in EU. Since there are significant differences and inconsistencies in the various studies related to this topic we proceed to clearly identify the key drivers behind CCS costs and analyse the technical and economic viability of coal fired power plants. Another import issue analysed in this paper is the price of carbon tax (EUA) necessary to make a power plant with CCS technology competitive in the current market.

Unlike similar studies in this field, which use deterministic or scenario based approach to evaluating the viability of coal-fired power plants with and without CCS, we base our simulation approach on parametric estimation of relevant market variables. We run Monte Carlo simulation in order to treat market variables, such as cost of capital, price of fuel, CO_2 and electricity as random variables and provide a more realistic and range based estimation.

The remainder of the paper is organized in the following manner: section 2 describes the data, provides technical and economic boundary conditions and provides model of referent power plant (IPP-REF) and equivalent power plant with CCS (IPP-CCS) and gives a clear link between chemical fossil fuel characteristic, plant characteristic and CO_2 emission costs. Also, in section 2 are shown expanded existing equations for the calculating cost metrics by directly accounting for the chemical properties of the feedstock. Section 3 presents the results of our market scenario simulation while in section 4 we analyse the consequences and implications of our obtained results. Finally, section 5 exposes the conclusions that we have reached.

2. Data, boundary conditions and methodology

The evaluation of emission obligations of both type of the independent power producer (IPP-REF and IPP-CCS) must begin with clear definition of boundaries (battery limits) of the project because boundary conditions have significant effects on the final results **(Global CCS institute, 2013)**. According to this technical and economic data, boundary conditions are clearly defined in section 2.1. Some of the data in this study can be applied globally whilst other data are specific only to the EU. In section 2.2. we present an improved methodology for CCS cost evaluation.

2.1.Boundary conditions

In this paper both types of the IPPs are similar coal-fired power plants. The IPP-REF has to purchase EUA for the entire amount of CO_2 produced, while the IPP-CCS has a CO_2 CCS, which results in higher energy requirements (**Global CCS institute, 2013**; **Sanpasertparnich et al., 2010)**. Boundary conditions are divided into technical boundary conditions (chapter 2.1.1.) and economic boundary conditions (chapter 2.1.2.).

2.1.1. Technical boundary conditions

Both the IPP-REF and the IPP-CCS are ultra-supercritical (USC) pulverized coal (PC) combustion plants based on an advanced ultra-supercritical conditions (USC) boiler equipped with an electrostatic precipitator (ESP) for fuel gas depulverisation and an advanced SNOX system, which allows a combined separation of both nitrogen and sulphur oxides with the production of high purity sulphuric acid as a by-product. Considering that the current proven and available technology for the pulverised coal (PC) fired plants designed by the Best Available Techniques (BAT) principle provides efficiency of 46% **(Van den Broek et al., 2009)**, and this paper assumes the efficiency to be 45,61 %. Most studies assume the CCS power plant with lower net plant output, but, in this study, the gross size of the IPP-CCS is adjusted to maintain the 500 MW of a net plant output, with efficiency of 35,61 %. The reason for this is assumption is the fact that the current technology causes the installation of the CCS system to lower the efficiency of the power plant by approximately ten percentile points requirements (**Global CCS institute, 2013; Rubin et al., 2011; ZEP 2010; Sanpasertparnich et al., 2010).** This is achieved by modelling a specific consumption curve with 0, 1st and 2nd degree coefficient of an hourly consumption curve (see chapter 2.1.1.1.). Because the ambient conditions are site-specific, it is assumed that the plant is in the EU, located in the vicinity of a port with an on-site utility system connecting the power plant to the grid. It is also assumed that both IPPs will operate with the base load of 7.000 hours equivalent to full load each year. Considering the location specificity, it is assumed that the best option for the IPP-CCS would be to choose a post combustion. The captured and the compressed CO_2 will be transported through a conventional pipeline (180 km) to the offshore saline aquifer (SA) in the Mediterranean. The capacity of this SA is 601.652 Mton and it is 930 m bellow the sea level **(Piani et al., 2012; Saftic et al. 2008).** The main technical data for the IPP-REF and IPP-CCS are shown in table 1.

Table 1 Technical parameters of the IPP-REF and IPP-CCS power plant

Technical parameters	IPP-REF	IPP-CCS
Type of plant	N-of-a-kind	N-of-a-kind
Plant location	EU	EU
Plant	40 years	40 years
Plant net output	500 MW	500 MW
Gross minimum power	300 MW	300 MW
Start-up fuel	Extra light fuel oil	Extra light fuel oil
Fuel	PC	PC
Boiler properties	USC	USC
Thermodynamic cycle	280 bar, 600 °C	280 bar, 600 °C
Efficiency at nominal power	45,61 %	35,61 %
Carbon capture efficiency	0 %	90 %
Flexibility	on a weekly basis	on a weekly basis
Ambient temperature	15 °C	15 °C
Ambient relative moisture	65 %	65 %
Ambient pressure	1013 mbar	1013 mbar
Cooling water temperature	16 °C	16 °C

Technical parameters	IPP-REF	IPP-CCS
Dispatch ramp rate (35-50% load)	5 MW/min	5 MW/min
Dispatch ramp rate (50-100% load)	10 MW/min	10 MW/min
Minimum run rate	35 % or lower	35 % or lower
Availability	85 % or higher	85 % or higher
Nominal system frequency	50 Hz	50 Hz
Nominal frequency variation	49,5/50,5 Hz	49,5/50,5 Hz
Highest/lowest frequency	47,5/51,5 Hz	47,5/51,5 Hz
Coal delivery method	ship	ship
Transmission system interconnect voltage	400 kV	400 kV
Switchyard included?	not included	not included
Transmission line included	not included	not included
Any special noise limitations?	no	no
Cooling water	sea water	sea water
Type of concept for CCS	/	post combustion
Pipeline distance and capacity	/	180 km, offshore
CO_2 transportation	/	pipeline
Preinjection reservoir identification and appraisal costs	/	not included
Post injection monitoring costs	/	not included
CO_2 purity	/	> 95,5%
Type of geologic storage site	/	saline aquifer, flat
Decommissioning of injection wells and monitoring wells	/	not included

The evaluation of the IPP emission costs is performed by defining levelised cost of electricity (*LCOE*) of the IPP-REF and the IPP-CCS. To define the *LCOE* it is necessary to create a model of the IPP-REF and the IPP-CCS. The IPP-REF does not have the CCS system installed and has an obligation to purchase emission unit allowances. Modelling of the IPP-REF starts with the coefficients of an hourly consumption curve that are shown in the table 2.

Table 2. Coefficients of an hourly consumption curve for the REF-IPP **(CESI, 2009)**

Coefficients of an hourly consumption curve for the IPP-REF	0 degree coefficient of an hourly consumption curve C_0 (GJ/h)	1^{st} degree coefficient of an hourly consumption curve C_1 (GJ/MWh)	2^{nd} degree coefficient of an hourly consumption curve C_2 (GJ/MW^{2}h)
Value	434,4665	6,609	0,0008287

In the operating range between the minimum and the maximum operating power of the IPP-REF hourly consumption is given by the quadratic hourly consumption curve.

$$C_{hc} = C_2 \cdot P^2 + C_1 \cdot P + C_0 \text{ (GJ/h)} \tag{1}$$

where C_{hc} = hourly consumption (GJ/h), P = operating power (MW), C_2 = 2^{nd} degree coefficient of hourly consumption curve (GJ/ MW^{2}h), C_1 = 1^{st} degree coefficient of an hourly consumption curve (GJ/MWh) and C_0 = 0 degree coefficient of an hourly consumption curve (GJ/h). Dividing the hourly consumption curve with the net power of the IPP gives a power plant net heat rate as it is shown in the equation (2) and in the figure 1.

$$HR = \frac{C_{hc}}{P} \text{ (GJ/MWh)} \tag{2}$$

where HR = net power plant heat rate (GJ/MWh), C_{hc} = hourly consumption (GJ/h) and P = net plant output (MW). From the net power plant heat rate it is possible to calculate the IPP efficiency, which is shown in the equation (3).

$$\eta = \frac{3600}{HR} \cdot 100 (\%) \tag{3}$$

where η = efficiency at nominal power (%) and HR = net power plant heat rate (MJ/MWh). From equation (3) it is possible to calculate the efficiency of the IPP-REF at nominal output power which is 45,61%

The IPP-CCS has the CO_2 capture and storage system with 90% efficiency and the remaining 10% goes into the atmosphere, so the IPP-CCS has the obligation to purchase emission allowances for them. Further, the CCS is energy intensive, so compared to the IPP-REF it has more emissions per MWh produced. Modelling of the IPP-CCS consists of determining the coefficients of an hourly consumption curve. The assumption is used that the CCS reduces the efficiency factor η by 10 percentile points (**Rubin et al., 2011; ZEP, 2011; Sanpasertparnich et al., 2010)**.

Using equations (1) – (3) the values of the coefficients C_2, C_1 and C_0 for the IPP-CCS are shown in the table 3.

Table 3. Coefficients of an hourly consumption curve for the IPP-CCS

Coefficients of an hourly consumption curve for IPP-CCS	0 degree coefficient of an hourly consumption curve C_0 (GJ/h)	1^{st} degree coefficient of an hourly consumption curve C_1 (GJ/MWh)	2^{nd} degree coefficient of an hourly consumption curve C_2 (GJ/MW^{2}h)
Value	730,64121	7,90771	0,00148

Using the equations (1) and (2) and data shown in the table 2 and the table 3 it is possible to create specific consumption curve for the IPP-REF and the IPP-CCS, as it is shown in the figure 1.

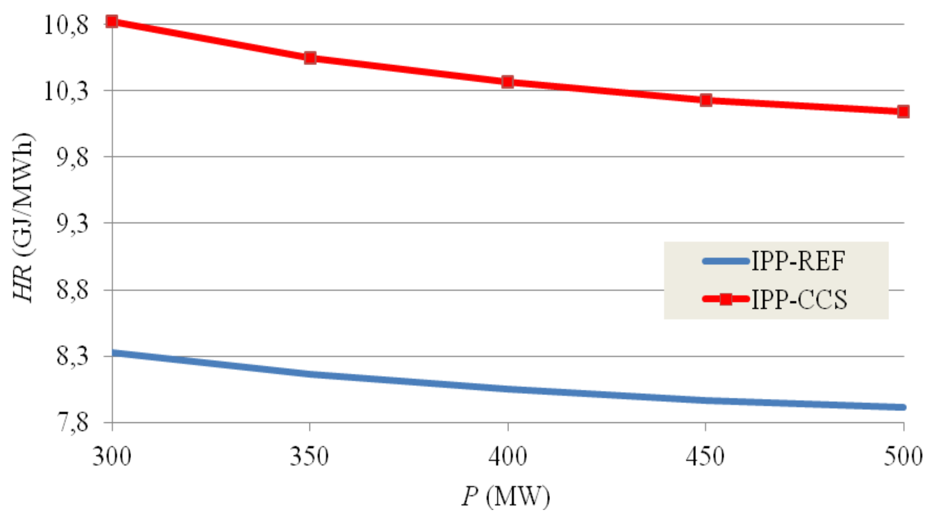


Figure 1. Specific consumption curve for the IPP-REF and the IPP-CCS

The CCS is energy intensive and the IPP-CCS has higher energy requirements which results with increased fuel consumption per each produced MWh. As it can be seen from figure 1, consumption depends on the output of the plant and it is higher when the plant is operating at the lower capacity. The lower efficiency and higher consumption result with increased emissions of CO_2 for IPP-CCS.

2.1.2. Financial boundary conditions

Financial boundary conditions are divided into investment costs, fixed operational and maintenance costs (*FOM*), variable operational and maintenance costs (*VOM*), fuel costs, emission cost due to purchasing CO_2 emission unit allowances (or taxes) and CO_2 transport and storage costs. The cost basis is for EU and because of that all reported costs are in Euros (€). Inflation and other price escalation rates are not taken into consideration. In our analysis, we use the period from 1st January 2009 to 1st January 2015, i.e., six years of daily data in order to obtain the values for 6-month Euribor, price of coal, and price of electricity. The only exception is the EUA data, which starts on 1st January 2013, coinciding with the beginning of Phase III of EU ETS. The third trading period of EUA signifies a step from mostly free allowances to market auctioning of CO_2 certificates and for this reason prices prior to and after January 2013 cannot be compared.

As a benchmark of electricity prices, we use Epex Spot Phelix Day-ahead Electricity Auction Baseload Index. On the Epex Spot day-ahead spot market hourly power contracts are traded for the delivery on the following day. The market is based on two-sided auction bidding to calculate prices in combination with a closed order book. The historical data refers to the day on which the contract was traded. Prior to December 21st 2012, Phelix auction results were sourced from EEX. After this date, the results are sourced from EPEX SPOT, which operates short-term power trading power in Germany, Austria, France and Switzerland. EEX holds a 50% stake in EPEX SPOT. Phelix Day Base is the average price of the hours 1 to 24 for electricity traded on the spot market. It is calculated for all calendar days of the year as the simple average of the auction prices for the hours 1 to 24 in the market area Germany/Austria disregarding power transmission bottlenecks. In table 4 we present the basic descriptive statistics for prices of electricity, CO_2, coal and cost of capital.

Table 4. Descriptive statistics of the market variables in the period 01/01/2009-01/01/2015*

	EPEX	CO2	NXA	EURIBOR**
Mean	41,27	5,19	2,75	2,09
Min	-56,87	2,66	1,9	1,34
Max	98,98	7,24	3,70	4,18
St dev	11,96	1,01	0,46	0,59

* EPEX prices are in Eur/MWh, CO2 in Eur/EUA, NXA in Eur/GJ and Euribor in percentage points

** Represents the price of the banking loan based on 6-month Euribor + 120 basis points

2.1.2.1. Investment costs

The total investment cost includes the engineering, procurement and construction (EPC) costs. It also includes owner's costs to develop the project, but exclude grid connection costs, and costs for erecting pipeline for transport of the captured CO_2. The costs of the investment consist of the cost of building the power plan,t and the costs of the capital of the power plant.

The price of building the power plant depends on the price of material, and the price of labour. The cost of the capital depends on the interest rate or on the expected rate of the refund in the invested capital, time needed for building the power plant, time of the refund of the investment and repayment of the loan. The economic life of the IPP-REF and the IPP-CCS is considered 20 years.

For the weighted average cost of capital (WACC) we use a mix of 30% equity and 70% bank loan. Cost of equity is set at 10% and the loan is a 20 year euro loan with variable interest rate based on 6-month Euribor plus 120 basis points of risk premium. Since the value of Euribor is changing daily our cost of capital varies over time but on average our WACC is 4,47%. The capacity factor is multiplied by the total number of hours in a year, (e.g., 8.766, including leap years).

2.1.2.2. Fixed operational and maintenance costs

The fixed operational and maintenance cost (*FOM*) includes spare parts and planned maintenance, overhauls, personnel and general and administrative costs. In this paper we presumed that the maintenance is 2 % of the total investment cost per each year. The insurance is 0,125% of the investment and general, and administrative costs are 0,05% of the investment (M€/year) **(CESI, 2009)**. The cost of personnel in the IPP-REF is given by multiplying each installed MW by 0,3 people by 16.500,00 € and for the IPP-CCS personnel the cost is calculated by multiplying 0,35 people by each installed MW by 16.500,00 €. Fixed operational and maintenance costs are given by equation (4).

$$FOM = x_m + x_{as} + x_{ga} + x_p \text{ (M€/year)} \tag{4}$$

where FOM are fixed operational and maintenance costs, x_m = maintenance cost (M€/year), x_{as} = assurance cost (M€/year), x_{ga} = general and administrative costs (M€/year) and x_p = personnel cost (M€/year).

2.1.2.3. Variable O&M costs

The variable operational and maintenance costs (*VOM*) are directly proportional to the amount of electricity generated, and include the costs of consumables like water and limestone and disposal costs (ash, gypsum etc). The VOM costs in this paper exclude fuel and cost for purchasing emission unit allowances, and it is presumed that variable O&M costs for the IPP-REF are 0,91 M€/year and for the IPP-CCS are 2,13 M€/year (for capacity factor 0,7985 which equals to 7.000 operation hours per year) **(CESI, 2009)**.

2.1.2.4. Fuel costs

As a benchmark for the price of hard coal we use NXA coal index from Bloomberg which is actually a North-West Europe - three multi-origin contracts for physical coal basis 6.000 kcal/kg NCV, delivered on a DES, DAP or FOB Barge basis at the ports of Amsterdam, Rotterdam or Antwerp. This coal may originate from Australia, Colombia, Poland, Russia, South Africa or United States (ACPRSU).

To determine the costs of the fuel, the average composition and the average heating value needs to be defined, as it is shown in the table 5.

Table 5. Average composition and the average fuel heating value **(Technical encyclopaedia, 1997)**

Fuel type	Lignite	Hard coal
Carbon (%)	40	60 - 75
Ash (%)	55	6 - 10
Hydrogen (%)	3,5	5 - 7
Oxygen (%)	18	21 - 26
Nitrogen (%)	1	1,5 - 1
Sulfur (%)	1	1 - 3
Heating value HV (GJ/t)	13-17	25 - 29

In this paper for baseline comparison a reference cost for hard coal is 72,87 € per ton. According to the fuel heating value (shown in the table 5), and in this study we took 26,5 GJ/t, so it turns out that the price is 2,75 €/GJ.

2.1.2.5. Emission cost due to purchasing the CO_2 emission unit allowances (taxes)

Since 1st January 2013 all the IPPs in EU are obligated to buy a licence for every emitted ton of CO_2 **(Directive 2009/29/EC, 2009)**. The average price of an allowance during 2014 is 5,63 €/tCO_2 **(European Energy exchange, 2014)**. This refers to both the IPP-REF and the IPP-CCS because its effectiveness of capture is 90% (IPCC, 2003; ZEP, 2011).

According to reported values the representative emission factor (EF) value for pulverized coal IPP-REF is 0,762 tCO_2/MWh and for PC IPP-CCS is 0,112 tCO_2/MWh (**Finkenkrauth, 2011; Rubin, 2007**) (both IPPs have the nominal power output of 500 MW). To be more precise the determination of CO_2 emission factor it is necessary to define CO_2 produced factor *PF* (tCO_2/t). The *PF* determines the amount of produced CO_2 per each MWh that has been produced by an IPP. In order to link the three building blocks (technical characteristics of the IPP, fuel characteristics and emission costs) in a coherent manner we suggest the following approach that starts with calculating the *PF* factor (equation 5):

$$PF = HR\frac{\psi}{HV} \tag{5}$$

where *PF* = CO_2 production factor (tCO_2/MWh) ψ = the amount of emitted CO_2 per unit mass of burned fuel, for solid and liquid fuel is expressed in (tCO_2/t) and for gases is expressed in (kgCO_2/Nm^3), *HR* = net power plant heat rate (GJ/MWh) (see equation 2) and *HV* = fuel heating value (GJ/t).

Determination of the ψ factor for solid fuel (coal or lignite) can be calculated by equation (6) **(Elektrane, 2000)**:

$$V_p = 1{,}867c + 1{,}244(9h + w) + 0{,}7s + 8{,}89(\lambda - 0{,}21)\left(c + 3\left(h - \frac{o - s}{8}\right)\right) \tag{6}$$

where Vp = the mass of gas generated by burning one kilogram of the coal (Nm^3/kg coal), c = the amount of carbon in the solid fuel (kg), the amount of hydrogen in the solid fuel (kg), w = amount of moisture in the solid fuel (kg), s = the amount of sulphur in the solid fuel (kg), o = the amount of oxygen in solid fuel (kg), and λ = air surplus (GJ/t).

First element on the right hand side of equation (6) determines the amount of produced CO_2. Using the fact that 1 kmol weight corresponds to the weight of each gas contained in 22,4 Nm^3 of that gas. Since 1 kmol of CO_2 weighs 44 kg it is possible to determine the amount of CO_2 emitted per unit mass of burned fuel by equation (7).

$$\psi = \frac{1{,}867 \cdot c}{22{,}4} \cdot 44 = 3{,}66 \cdot c \tag{7}$$

By including equations (1), (2) and (7) in equation (5) CO_2 production factor can be calculated as shown in the equation (8).

$$PF = \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \cdot \frac{3{,}66 \cdot c}{HV} \tag{8}$$

It is important to highlight that the amount of CO_2 produced by IPP-CCS is higher in comparison with IPP-REF because IPP-CCS has higher energy requirements (see figure 1.). CO_2 production factor for the IPP-REF equals the CO_2 emission factor because IPP-REF does not have CCS. Since the IPP with integrated CCS system does not have a 100% efficiency of capturing CO_2 IPP-CCS also has the obligation of purchasing emission allowances.

It is necessary to distinguish between the amount of CO_2 produced and CO_2 emitted and thus we calculate the emission factor (EF) which shows the true amount of CO_2 emitted into the atmosphere. We do this by extending the equation (8) with the coefficient of efficiency of capturing CO_2 CE, as shown in the equation (9).

$$EF = \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \cdot \frac{3{,}66 \cdot c}{HV} \cdot (1 - CE) \tag{9}$$

where *EF* is the emission factor (tCO_2/MWh), *CE* is the coefficient of efficiency of capturing CO_2 (%), for IPP-REF it is 0 % and for IPP-CCS is between 0,85-0,95 % (**ZEP, 2015; IPCC, 2005; Rubin, 2015**). Finally, by multiplying the emission factor *EF* with the emission unit allowance cost *CC* it is possible to determine the levelised cost of CO_2 emission tax for the IPP-REF and the IPP-CCS, as shown in equation (10).

$$LCO = \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \cdot \frac{3{,}66 \cdot c}{HV} \cdot (1 - CE) \cdot CC \tag{10}$$

Where *LCO* is levelised emission cost due to purchasing CO_2 emission unit allowances (taxes) and *CC* is emission unit allowance cost (€/tCO_2).

2.1.2.6. CO_2 transport costs

Transportation of the captured CO_2 can be achieved through pipelines (onshore and offshore) and ships, and it can be calculated by equation (11)

$$CO_{2t} = CE \cdot \frac{B_2 \cdot P^2 + B_1 \cdot P + B_0}{P} \frac{3{,}66 \cdot c}{HV} \cdot C_{ct} \; (\text{€/MWh}) \tag{11}$$

where CO_{2t} = levelised CO_2 transport cost (€/MWh) and C_{ct} = unit transportation cost (€/ton). The IPP-CCS in this paper is located in the EU in the immediate vicinity of the coast and the CO_2 will be stored in offshore SA in the Mediterranean. According to ZEP transport cost estimates we assume C_{ct} to be 4,08 €/tCO_2 **(ZEP, 2011)**.

2.1.2.7. CO_2 storage costs

Captured CO_2 can be disposed in deep geological sequestration, mineral carbonation, or ocean storage. There are three geological formations that have also been recognized as major potential CO_2 sinks: deep saline-filled sedimentary, depleted oil and natural gas reservoirs, and abandoned coal seams. Preinjection reservoir identification, appraisal costs and post injection monitoring costs are not included in this paper. Levelised CO_2 storage cost is calculated by the equation (12).

$$CO_{2s} = CE \cdot \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \frac{3{,}66 \cdot c}{HV} \cdot C_{cs} \ (\text{€/MWh}) \tag{12}$$

where CO_{2s} = levelised CO_2 storage cost (€/MWh), CE = coefficient of capture efficiency (for the IPP-REF $CE = 0$, and for the IPP-CCS $CE = 0{,}9$), HR = net power plant heat rate (GJ/MWh), ψ = amount of the CO_2 emitted per unit mass of burned fuel, according to equation 7, HV = heating value (GJ/t), CC = emission unit allowance cost (€/tCO_2), C_{cs} = unit costs for storage. According to ZEP storage cost estimates we assume C_{cs} to be 4,5 €/tCO_2 **(ZEP, 2011)**.

2.2. Calculating Key Cost Metric: Levelised cost of electricity (LCOE)

There are many differences and inconsistencies across different papers and studies in methods, metrics and assumptions in evaluation of the CO_2 emission costs for a fossil fuel power plant **(see Rubin, 2012 for the overview)**. Because the IPP-CCS has not yet been implemented on full commercial scale, to properly quantify the cost of the CCS system it is necessary to have properly defined cost metrics. Calculating metrics is based on calculation of the levelised cost of electricity (LCOE). The LCOE is widely used to define a characteristic cost of electricity generation. For calculating the LCOE of the IPP-REF and the IPP-CCS we have to define investment, fixed and variable operation and maintenance costs, fuel cost, emission unit allowances cost, transport and storage costs, as it is shown in the table 6. The cost of the CCS is the difference between the LCOE of the IPP-REF and the IPP-CCS.

Table 6. Basic components of the LCOE

Basic components of levelised cost of electricity (€/MWh)	1.	levelised investment costs	*IC* (€/MWh)
	2.	levelised fixed O&M costs	*FOM* (€/MWh)
	3.	levelised variable O&M costs	*VOM* (€/MWh)
	4.	levelised cost of fuel	*LF* (€/MWh)
	5.	levelised cost of purchasing emission taxes	*LCO* (€/MWh)
	6.	levelised costs of CO_2 transport	CO_{2t} (€/MWh)
	7.	levelised costs of CO_2 storage	CO_{2s} (€/MWh)

Finally, due to the equations (1) – (12) we suggest that the LCOE for IPP-REF and IPP-CCS can be defined through the equation (13).

$$LCOE = \frac{TCR \cdot FCF + FOM}{CF \cdot 8766 \cdot P} + VOM + \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \cdot FC + \\ + \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \frac{3{,}66 \cdot c}{HV} \cdot CC \cdot (1 - CE) + \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \frac{3{,}66 \cdot c}{HV} \cdot CE(C_{ct} + C_{cs}) \qquad (13)$$

The most common metrics which are used in this paper are increased cost of electricity (*ICOE*) (€/MWh), cost of CO_2 avoided (CO2avoided) (€/tCO_2) and cost of CO_2 captured (CO2captured) (€/tCO_2). Because the CO_2 avoided (€/tCO_2) and the CO_2 captured (€/tCO_2) are reported in similar units (currency e.g. € per ton CO_2) there is a possibility of misunderstanding. It is important to distinguish these two cost metrics. In calculating the CO_2 avoided costs, the cost of transport and storage of CO_2 must be included because emissions of CO_2 are not avoided until this captured CO_2 is not transported to the storage locations. In calculating the CO_2 captured, these should not be taken into consideration. Because of this, the costs of CO_2 captured are lower than costs of the CO_2 avoided. Considering the aforementioned terms shown in the table 6 and equation (13) it should be highlighted that the LCOE of electricity production by IPP-REF and specially for the IPP-CCS depends on the many different factors and the devil is in the details **(Rubin, 2012; IPCC, 2005)**. This details who also affect to all three CO_2 metrics are:

- total capital requirement,
- fixed charge factor
- fixed operating and maintenance costs,
- capacity factor,
- net plant capacity,
- variable operating and maintenance costs,
- specific consumption curve (heat rate),
- unit fuel cost,
- fuel heating value,
- the amount of carbon in the fuel,
- the amount of CO_2 produced per unit mass of burned fuel,
- amount of emitted CO_2 for each produced MWh,
- emission unit allowance cost,
- coefficient of capture efficiency,
- transportation cost and
- storage cost.

2.2.1. Increased cost of electricity (*ICOE*)

Increased cost of electricity (*ICOE*) is the difference between cost of IPP-CCS and IPP-REF and it is given in equation (14).

$$ICOE = LCOE_{CCS} - LCOE_{REF} = \left\{ \frac{TCR \cdot FCF + FOM}{CF \cdot 8766 \cdot P} + VOM + \frac{C_2 \cdot P^2 + C_1 \cdot P + C_0}{P} \cdot FC + \right.$$

$$+\frac{C_2\cdot P^2+C_1\cdot P+C_0}{P}\frac{3{,}66\cdot c}{HV}\cdot CC\cdot\left(1-C_{ce}\right)+\frac{C_2\cdot P^2+C_1\cdot P+C_0}{P}\frac{3{,}66\cdot c}{HV}\cdot C_{ce}\left(C_{ct}+C_{cs}\right)\Bigg\}_{CCS}-$$

$$-\left\{\frac{TCR\cdot FCF+FOM}{CF\cdot 8766\cdot P}+VOM+\frac{C_2\cdot P^2+C_1\cdot P+C_0}{P}\cdot FC+\right.$$

$$\left.+\frac{C_2\cdot P^2+C_1\cdot P+C_0}{P}\frac{3{,}66\cdot c}{HV}\cdot CC\right\}_{REF} \tag{14}$$

where $ICOE$ = increased cost of the electricity (€/MWh), $LCOE_{CCS}$ = levelised cost of electricity of IPP-CCS (€/MWh), $LCOE_{REF}$ = levelised cost of electricity of IPP-REF (€/MWh). This cost measure can also be applied to individual plants or a collection of plants, so the clear understanding of the context is very important.

2.2.2. Cost of CO_2 avoided

The CO_2 avoided compares the cost of the IPP-CCS to the cost of the IPP-REF **(Rubin, et al., 2007; Rao et al. 2002)** and this cost equals the emission unit allowances (or carbon tax) at which the LCOE of the IPP-REF equals the LCOE of the IPP-CCS **(Rubin, 2012)**.

$$CO_2avoided=\frac{ICOE}{EF_{REF}-EF_{CCS}}=\frac{ICOE}{\left(HR\frac{3{,}66\cdot c}{HV}\right)_{REF}-\left(HR\frac{3{,}66\cdot c}{HV}(1\text{-}\mathrm{CE})\right)_{CCS}}\ \left(€/\mathrm{tCO_2}\right) \tag{15}$$

where the $LCOE_{CCS}$ is the levelised cost of electricity generation from the IPP-CCS (€/MWh), the $LCOE_{REF}$ is levelised cost of electricity generation of the IPP-REF (€/MWh), EF_{REF} = amount of emitted CO_2 of the IPP-REF (tCO_2/MWh) and EF_{CCS} = amount of the emitted CO_2 of the IPP-CCS (tCO_2/MWh).

2.2.3. Cost of CO_2 captured

The CO_2 captured cost can be defined as shown in the equation (16) **(Rubin, 2012)**.

$$CO_2captured=\frac{LCOE_{CCS}-LCOE_{REF}}{t_{cap}}=\frac{ICOE}{HR\frac{3{,}66\cdot c}{HV}CE}\left(€/\mathrm{tCO_2}\right) \tag{16}$$

where $LCOE_{CCS}$ is the levelised cost of electricity generation of IPP-CCS (€/MWh), $LCOE_{REF}$ is levelised cost of electricity generation of IPP-REF (€/MWh), t_{cap} = amount of captured CO_2 per net MWh for IPP-CCS (tCO_2/MWh) which equals 0,9 x PF_{CCS}.

The purpose of the CO_2 captured is to quantify only the cost of capturing CO_2 and this cost metric must exclude the costs of CO_2 transport and storage. This is the reason why the cost of CO_2 captured is always lower than the cost of the CO_2 avoided.

3. Results

After distribution fitting of market variables and obtaining the distribution parameters we proceed with calculating the levelised cost of fuel, levelised cost of investment, levelised cost of electricity and cost of CO_2 avoided, as proposed by **Rubin (2012**). We extend the analysis and comparison of REF and CCS power plants in three directions.

Our first extension is that instead of a deterministic or scenario based approach to evaluating the viability of coal-fired power plants with and without CCS we employ a parametric simulation based approach. We allow for the market variables (cost of capital, price of fuel, CO_2 and electricity) to be treated as random under a predetermined probability density function and in that way obtain a probabilistic and range based estimates of our results.

Second extension is that we use the market prices of electricity to calculate the profit and loss (P/L) from operating the power plants at different capacities. Third extension is the calculation and analysis of the marginal levelised cost of electricity, cost of CO_2 avoided and profit and loss. Marginal effect separates the operating costs from the investment costs and excludes them. In this manner, we can analyse the purely operational costs, which provides us with an important insight into the real costs and viability of older power plants that have already been depreciated. This information is important for EU since the majority of coal-fired power plants are close to or beyond their economic life.

We proceed with the classical baseline scenario analysis of the IPP-CCS and IPP-REF producers. In the following section, using the same technical characteristics of the IPP-CCS and

IPP-REF power plants, we perform the analysis based on parametric simulation of variables and compare the results.

3.1 Baseline market scenario results

The baseline market scenario comparison is based on calculating the key metrics and technical and financial assumptions shown in chapter 2. In this scenario, cost of emission unit allowances is presumed to be 0 €/tCO_2, fuel cost 65 €/t, and capacity factor 0,7985 and the amount of carbon in the coal is 0,66 %. In order to clearly specify all the cost of the IPP-REF and IPP-CCS, the results are sorted according the basic components of the LCOE shown in table 6. All the data in the baseline scenario are derived from equation (1) to (16), and the results are shown in the table 7.

Table 7. Baseline market scenario results

	Name	Mark	IPP-REF	IPP-CCS
	Net power plant heat rate	*HR* (GJ/MWh)	7,892	10,108
	Efficiency at maximum power	η (%)	45,61	35,61
	Total Capital Requirement in the base year of the analysis	*TCR* (M€)	800	1.150
	Net power output of the plant	*P* (MW)	500	500
	Fixed charge factor	*FCF* (%)	10,76	10,76
	Economic life of the power plant	*T* (years)	20	20
	Capacity factor	*CF* (fraction)	0,7985	0,7985
1.	**Levelised investment cost**	***IC* (€/MWh)**	**17,33**	**29,84**
	Maintenance	x_{fm} (M€/year)	1,6	2,3
	Assurance	x_{as} (M€/year)	1	1,437
	General and Administrative	x_{ga} (M€/year)	0,4	0,575
	Personnel	x_{pe} (M€/year)	2,475	2,888
2.	**Levelised fixed O&M costs**	***FOM* (€/MWh)**	**5,679**	**7,971**
3.	**Levelised variable O&M costs**	***VOM* (€/MWh)**	**0,91**	**2,14**
	Fuel cost per unit of energy	*FC* (€/GJ)	2,75	2,75
	Fuel heating value	*HV* (GJ/t)	26,5	26,5
4.	**Levelised fuel cost**	***LF* (€/MWh)**	**21,7**	**27,79**
	Production factor	*PF* (tCO_2/MWh)	0,7266	0,9307
	Emission factor	*EF* (tCO_2/MWh)	0,7266	0,0931
	Price of emission unit allowance	*CC* (€/tCO_2)	0	0
	Coefficient of capture efficiency	*CE* (fraction)	0	0,9
5.	**Levelised cost of CO_2 tax**	***LCO* (€/MWh)**	**0**	**0**
	CO_2 transport cost	C_{ct} (€/tCO_2)	/	4,08
6.	**Levelised cost of CO_2 transport**	$\boldsymbol{CO_{2t}}$ **(€/tCO_2)**	**/**	**3,418**
	CO_2 storage cost	C_{cs} (€/tCO_2)	/	4,5
7.	**Levelised cost of CO_2 storage**	$\boldsymbol{CO_{2s}}$ **(€/tCO_2)**	**/**	**3,769**
	Levelised cost of electricity	***LCOE* (€/MWh)**	**45,62**	**74,93**
	Increased cost of electricity	***ICOE* (€/MWh)**	**29,31**	

Because it is very difficult to forecast future prices of EUA, calculation of the LCOE prices are made by assuming the EUA prices of 20 €/tCO_2, 40 €/tCO_2 and 80 €/tCO_2. The results are shown in the figure 2.

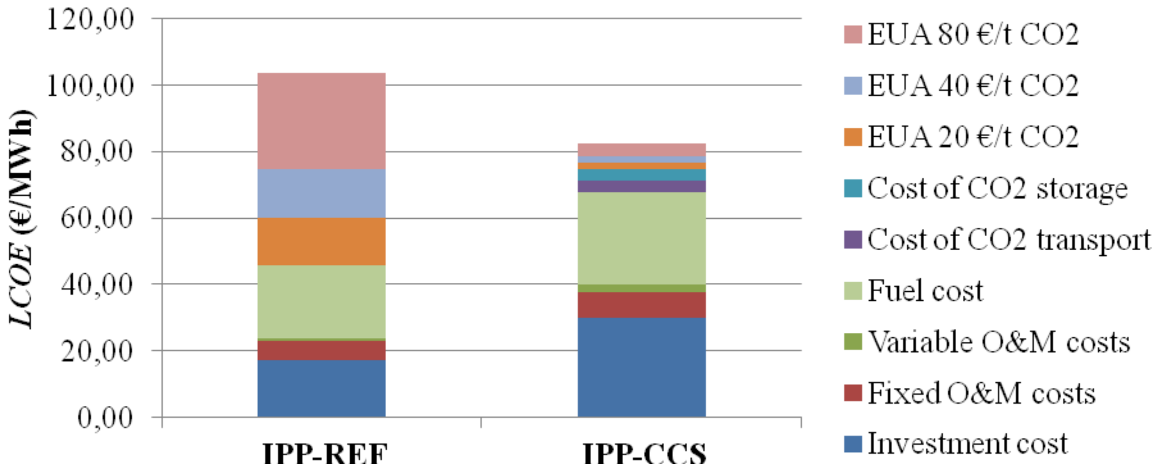


Figure 2. LCOE comparisons between the IPP-REF and the IPP-CCS with different EUA prices for the baseline market scenario

Figure 2 shows the huge impact of EUA prices on levelised cost of electricity of IPP-REF without the CCS. With the price of EUA = 0 €/tCO_2 the LCOE of the IPP-REF is 45,62 €/MWh, and the LCOE of the IPP-CCS is 74,93 €/MWh. Rising the EUA costs strongly affect the IPP-REF, whilst the IPP-CCS changes only slightly. This causes the LCOE intersection at the EUA value of 46,25 €/tCO_2, which represent the cost of CO_2 avoided (equation 15). This means that at that EUA price CCS technology become competitive on the free market. The cost of CO_2 captured is 26,40 €/tCO_2.

3.2. Parametric simulation results

In order to perform our Monte Carlo simulation of coal-fired REF and CCS power plants we proceed with finding the distributions that best fit our historical data (period 2009-2015). EPEX electricity prices are best described by the Student T distribution, EUA by Generalized Extreme Value distribution (GEV), 6-month Euribor interest rate by Inverse Gaussian (IG) and coal prices by Log-normal distribution. The parameters of the fitted distributions for the analysed market variables are presented in table 8.

Table 8. Estimated distributions and parameters for selected market variables

	EPEX	CO2	EURIBOR	NXA
Distribution	T	GEV	IG	LogN
μ	41,5025 (0,2432)	4,9031 (0,0516)	2,0919 (0,0151)	0,9754 (0,0051)
σ	10,3401 (0,2243)	1,0319 (0,0386)		0,1184 (0,003)
k		-0,2825 (0,0279)		
ν	5,7970 (0,9532)			
λ			25,7495 (0,9219)	

From the obtained results, it is visible that the data generating processes of these variables are not governed by the Gaussian distribution since all the fitted distributions are either fat tailed or asymmetric or both. This finding is consistent with the characterstics of high frequency energy commodities' data (see **Žiković, Weron, Tomas Žiković, 2015**). The obtained distributions are used as inputs into the simulation of metrics describing the power plant economics (see **Rubin, 2012**). We present the obtained simulation results in table 9. Minimum, 5-th percentile, mean, 95-th percentile, maximum and standard deviation are presented for each metric.

Table 9. Levelised investment cost, cost of fuel and cost of CO_2 avoided for IPP REF and CCS (prices in €)

	Min	5-th perc	Mean	95-th perc	Max	St dev
FCF_RE	5,99%	6,60%	7,56%	8,81%	11,08%	0,71%
IC_RE	13,85	15,26	17,48	20,38	25,60	1,64
LCOF_REF_500	13,77	17,38	20,97	25,09	29,02	2,40
LCOF_REF_400	14,00	17,67	21,32	25,51	29,50	2,44
LCOF_REF_300	14,48	18,28	22,05	26,39	30,51	2,52
FCF_CC	7,49%	8,10%	9,06%	10,31%	12,58%	0,71%
IC_CC	24,89	26,92	30,11	34,28	41,79	2,36
LCOF_CCS_500	17,64	22,26	26,86	32,14	37,16	3,07
LCOF_CCS_400	18,02	22,74	27,44	32,83	37,96	3,14
LCOF_CCS_300	18,82	23,75	28,66	34,30	39,66	3,28
REFCCS_500_breakeven	30,48	34,59	37,52	40,64	45,48	1,82
REFCCS_400_breakeven	30,29	34,42	37,36	40,52	45,32	1,83
REFCCS_300_breakeven	29,95	34,10	37,06	40,24	45,02	1,84
MREFCCS_500_breakeven	11,30	13,11	15,58	17,99	20,14	1,47
MREFCCS_400_breakeven	11,41	13,25	15,74	18,18	20,37	1,48
MREFCCS_300_breakeven	11,63	13,51	16,07	18,58	20,85	1,52

Fixed charge factor (FCF) of IPP CCS is increased, compared to the IPP REF, due to first of its kind (FOIK) risk. In similar studies this risk premium is set at 3% but since at least two such projects should come online in 2017 we kept the risk premium but at a decreased rate of 1,5%. Significant difference can be seen in the levelised investment cost between the two IPP's but this was to be expected since investment costs of CCS are 44% higher than those of REF. Levelised cost of fuel is also elevated in case of IPP CCS due to higher heat rate of CCS plant i.e. lower efficiency.

Cost of CO_2 captured represents the breakeven point between IPP-REF and IPP-CCS since it gives the price of EUA certificates at which the financial performance of both plants would be equal. Mean value of cost of CO_2 captured is 37,52 €/tCO_2 (90% probability space spanning between 34,59 and 40,64 €/tCO_2), which is approximately five times higher than the current market price. A number of similar studies obtained higher values for EUA, but our price distribution reflects the decreased cost of debt financing, decreased FOIK, as well as lower CCS transportation and storage costs. Marginal cost of CO_2 captured shows the breakeven point between IPP REF and IPP CCS excluding the investment costs. It shows what would be the breakeven point between the two IPP's in case both plants had their initial investment depreciated. Naturally in this case the required price of EUA needed to reach equilibrium drops significantly to its mean value of 15,58 €/tCO_2 and 90% probability space spanning between 13,11 and 17,99 €/tCO_2.

After calculating the levelised price of electricity, we proceed with calculating the profit and loss (P/L) distribution of IPP's based on the obtained distribution of market prices (EPEX). P/L is obtained by simply subtracting random number from EPEX price distribution from LCOE distribution.

$$P/L = LCOE – EPEX \quad (17)$$

Marginal P/L is the P/L without investment costs reflecting the profitability of older plants that had their initial investment depreciated and face only the operating expenses.

$$M\ P/L = LCOE - IC – EPEX \quad (18)$$

Levelised cost of electricity and profit and loss results for IPP REF are presented in table 10.

Table 10. Levelised cost of electricity and profit/loss results for IPP REF (prices in €)

	Min	5-th perc	Mean	95-th perc	Max	St dev
LCOE_REF_500	41,06	44,15	48,96	54,11	61,15	2,98
LCOE_REF_400	41,39	44,50	49,37	54,56	61,66	3,02
LCOE_REF_300	42,08	45,24	50,24	55,55	62,73	3,09
MLCOE_REF_500	24,34	27,63	31,48	35,75	39,71	2,51
MLCOE_REF_400	24,63	27,98	31,89	36,24	40,26	2,55
MLCOE_REF_300	25,25	28,71	32,76	37,25	41,42	2,64
P/L_REF_500	-57,16	-27,93	-7,18	12,05	50,31	12,53
P/L_REF_400	-57,54	-28,34	-7,59	11,69	49,95	12,54
P/L_REF_300	-58,35	-29,19	-8,46	10,92	49,20	12,56
MP/L_REF_500	-37,85	-9,73	10,30	28,97	70,58	12,38
MP/L_REF_400	-38,23	-10,17	9,89	28,61	70,22	12,39
MP/L_REF_300	-39,04	-11,08	9,02	27,87	69,47	12,41

From the distribution space we obtained from P/L and MP/L we can also calculate the probability of IPP yielding a positive business result. In the case of IPP-REF, given the analysed market parameters, there is a 26,9% probability of yielding a profit. Based on the marginal P/L, probability for a depreciated IPP-REF to yield a positive result is 83%.

Table 11. Levelised cost of electricity and profit/loss results for IPP CCS (prices in €)

	Min	5-th perc	Mean	95-th perc	Max	St dev
LCOE_CCS_500	61,00	65,50	71,46	78,16	88,70	3,84
LCOE_CCS_400	61,48	66,10	72,13	78,92	89,54	3,89
LCOE_CCS_300	62,50	67,37	73,55	80,54	91,33	4,00
MLCOE_CCS_500	32,13	36,73	41,35	46,63	51,58	3,07
MLCOE_CCS_400	32,61	37,30	42,02	47,41	52,47	3,14
MLCOE_CCS_300	33,61	38,51	43,44	49,07	54,36	3,28
P/L_CCS_500	-79,91	-51,16	-29,68	-10,67	27,55	12,83
P/L_CCS_400	-80,53	-51,90	-30,35	-11,31	26,97	12,84
P/L_CCS_300	-81,84	-53,31	-31,77	-12,68	25,74	12,88
MP/L_CCS_500	-47,17	-19,60	0,43	19,88	61,67	12,56
MP/L_CCS_400	-47,79	-20,41	-0,24	19,25	61,09	12,58
MP/L_CCS_300	-49,10	-21,98	-1,66	17,90	59,86	12,62

In the case of IPP-CCS, given the analysed market parameters, there is only a 0,9% probability of yielding a profit. Based on the marginal P/L, probability for a depreciated IPP-CCS to yield a positive result is 51,1%.

Levelised cost of investment for our two coal fired power plants is shown in figure 3. As can be seen the two barely overlap primarily due to 44% higher initial CAPEX and a 1,5 percentage points higher FCF on the side of the CCS plant.

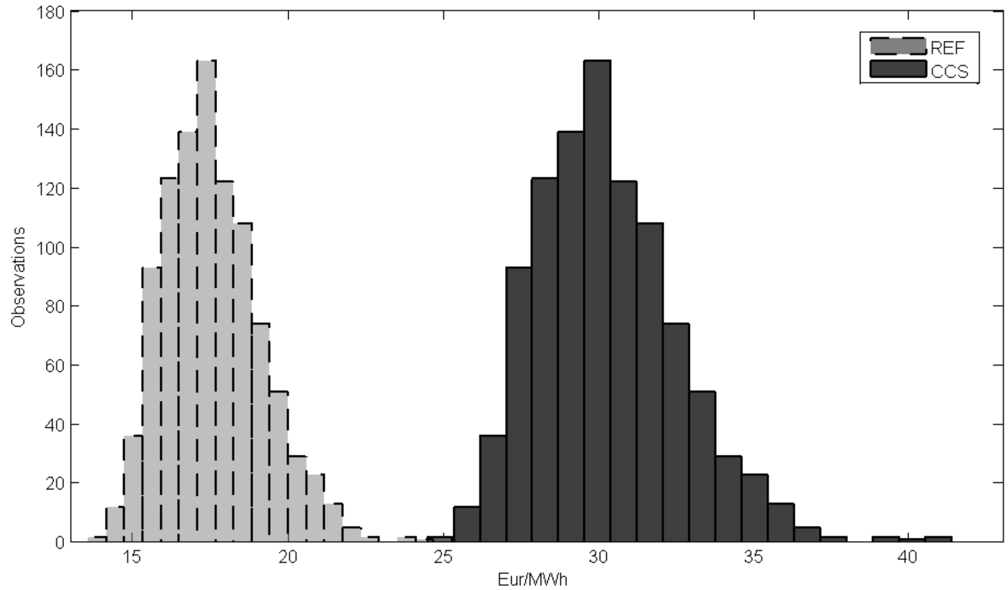
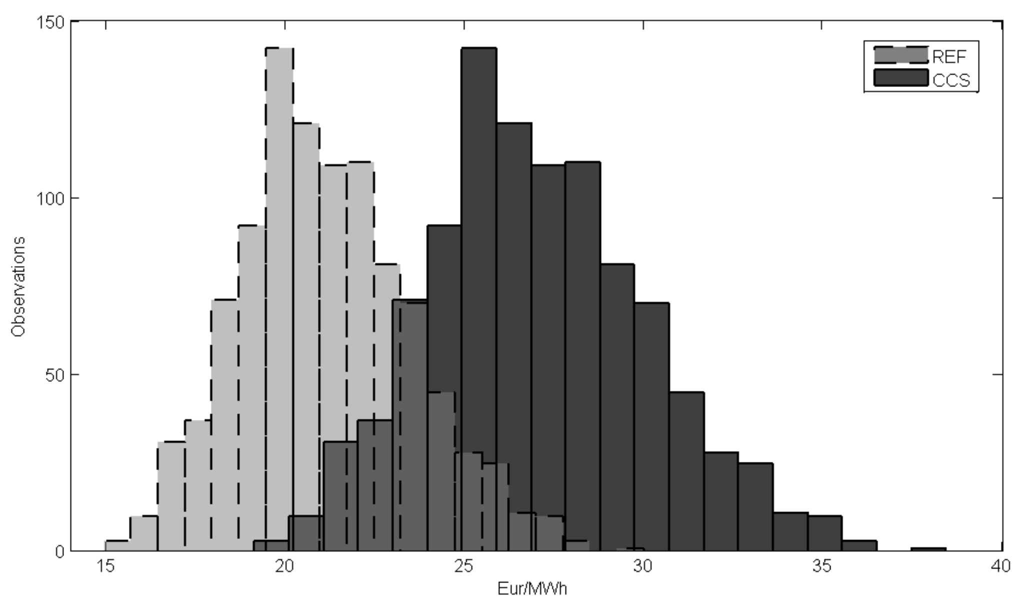


Figure 3. Levelised cost of investment for REF and CCS operating at nominal power output

Levelised cost of fuel presented in figure 4 shows the effect of the market price of the coal and its volatility. Naturally, due to higher efficiency of REF power plant compared to CCS, the LCOF is significantly skewed in favour of the former.



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igure 4. Levelised cost of fuel for REF and CCS operating at nominal power output

Figure 5 shows the distribution of the cost of CO_2 avoided, i.e., the breakeven point between REF and CCS plant. As mentioned earlier, the majority of the distribution mass is situated between 35 and 40 €/tCO_2 meaning that in this range of EUA prices CCS plant's economics equal those of a REF plant. Marginal cost of CO_2 avoided, i.e., marginal breakeven point shows the EUA breakeven prices without the investment costs. This rationale would be applicable to older plants that had their initial investment depreciated and face only the operating expenses.

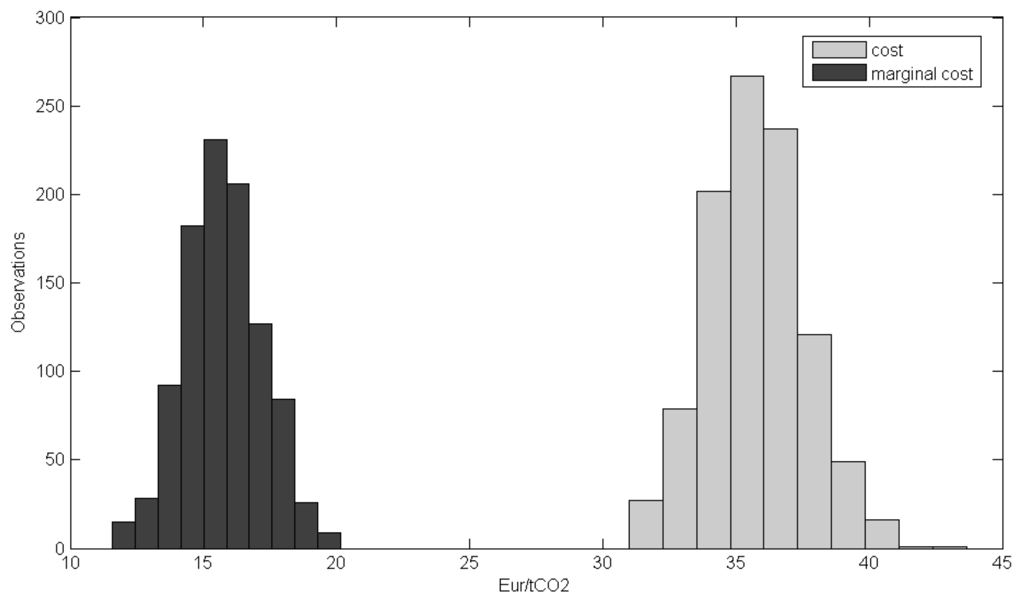

Figure 5. Cost and marginal cost of CO_2 avoided, IPP operating at nominal power output

From the previous building blocks, we can calculate the distribution of LCOE for the REF and CCS plant. Figure 6 shows that the two LCOE distributions do not overlap meaning that, given the initial costs and FCF difference, lower efficiency and historical behaviour of EUA prices, levelised cost of producing electricity for a CCS plant is significantly higher and basically uncompetitive. Figure 7 shows the marginal effect, i.e., disregarding the investment costs, and the differences in LCOE between the REF and CCS are somewhat lower, but still the REF plant clearly dominates. We can conclude that although the differences in investment costs and FCF are significant the main driver behind the LCOE difference is the EUA price. As long as the EUA prices remain at current low levels it cannot be realistically expected that CCS plants might freely compete with REF plants.

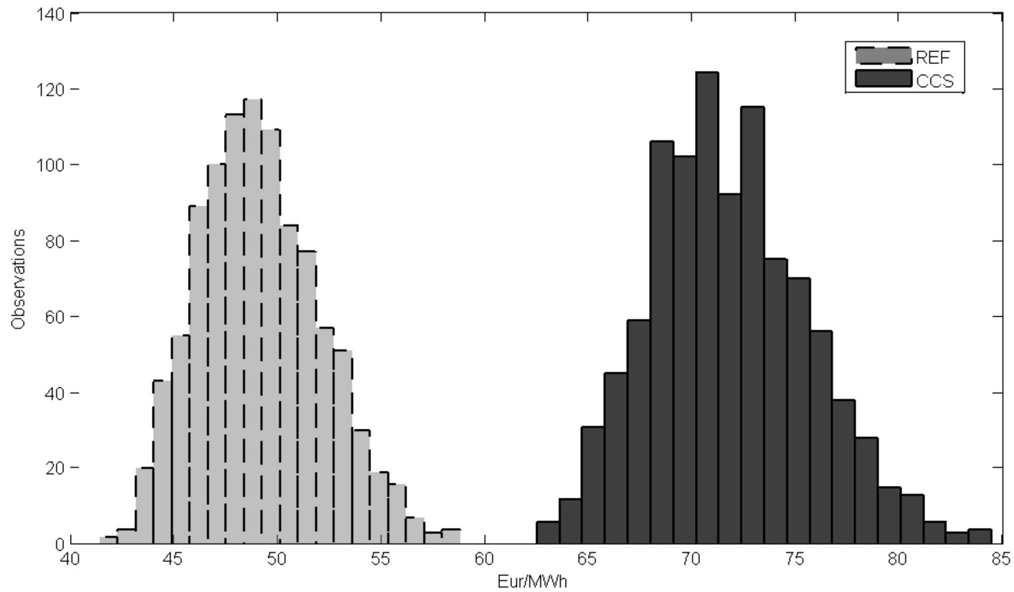

Figure 6. Levelised cost of electricity for REF and CCS operating at nominal power output

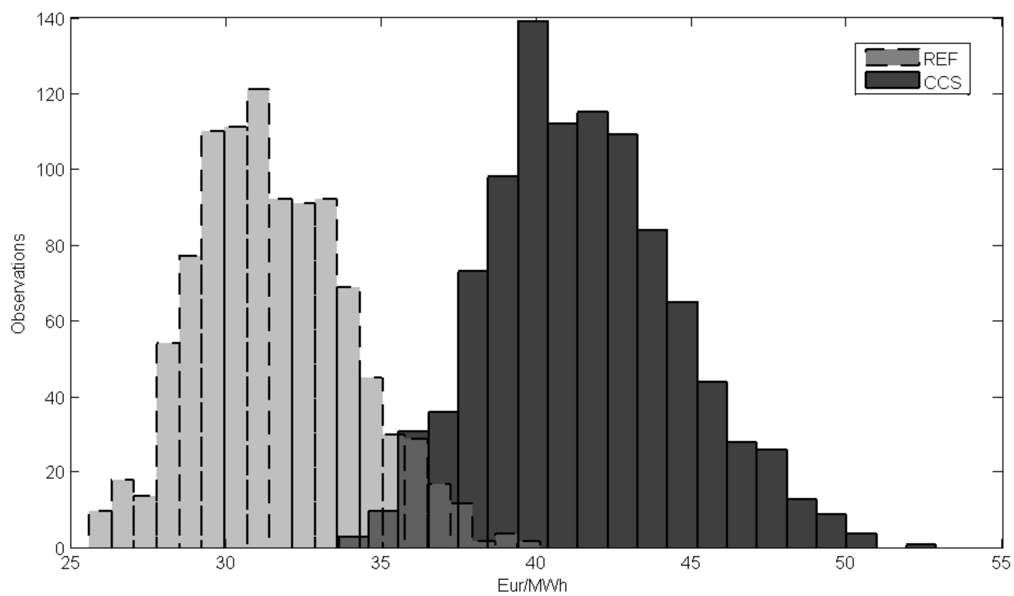

Figure 7. Marginal levelised cost of electricity for REF and CCS operating at nominal power output

Figures 8 and 9 show the profit and loss distribution of IPP-REF and IPP-CCS plants. The obtained results are in line with the ones obtained for LCOE. Since the market electricity prices (EPEX) are on average in the low to mid 40 €/MWh and CCS LCOE minimum value is

61 €/MWh it is highly unlikely that CCS plants can function in the current market. When looking at the marginal profit and loss distribution, the situation improves for a hypothetical "old" CCS plant. With the current price of electricity and EUA the probability of yielding a positive financial result for an "old" CCS plant is around 51%. To summarize, IPP-CCS plants, with the current technology, cannot survive a free market competition with classical IPP-REF coal plants. For the IPP-CCS to become economically competitive either the market price of electricity or the price of EUA should significantly rise.

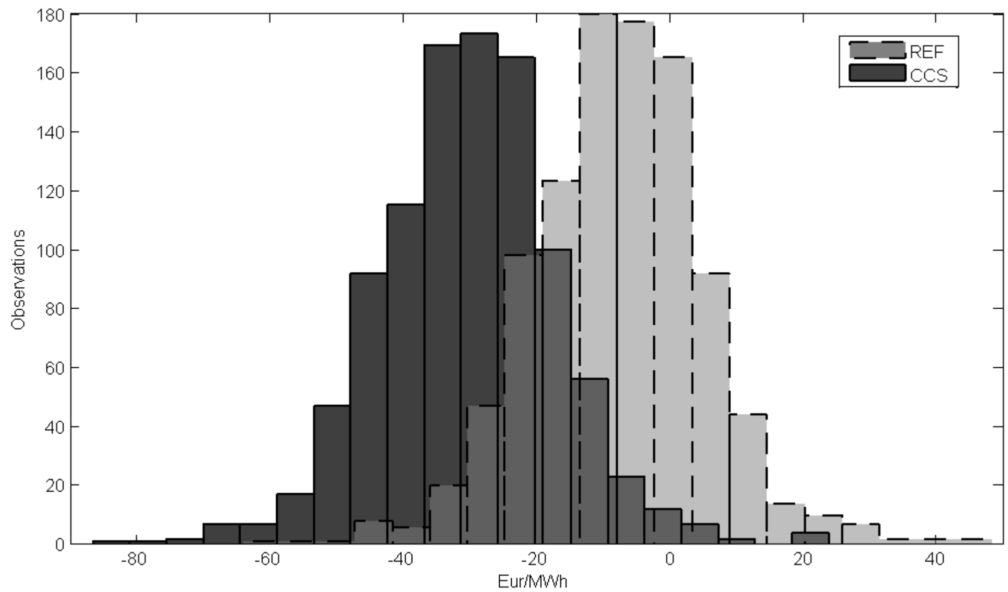

Figure 8. P/L distribution for REF and CCS operating at nominal power output

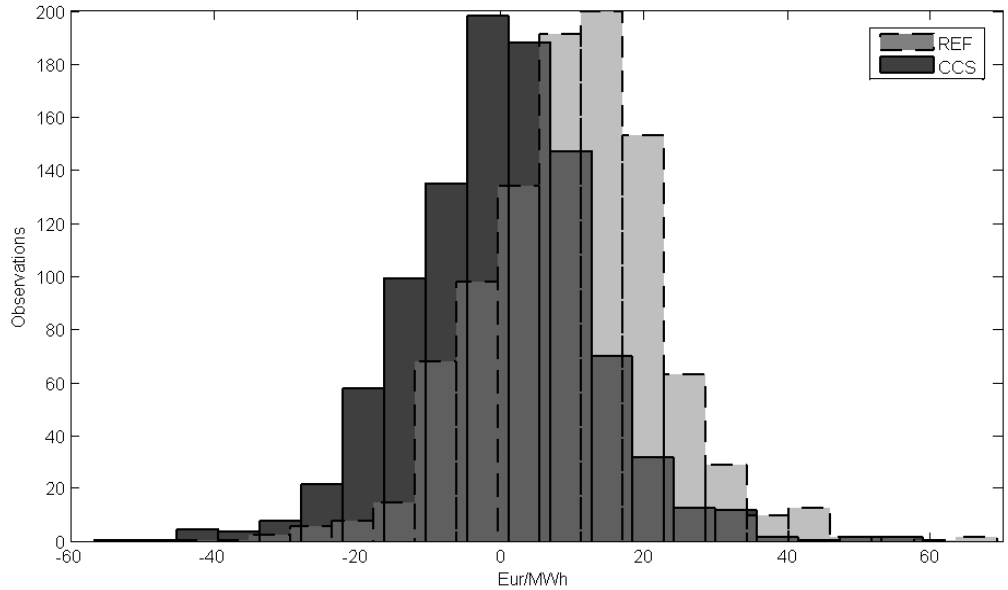

Figure 9. Marginal P/L distribution for REF and CCS operating at nominal power output

The information obtained in the presented distribution charts can also be presented in a simpler manner as seen in figure 10. Figure 10 shows the LCOE of IPP-CCS and IPP-REF dependent on the price of EUA. Each point of the CCS and REF lines was obtained by simulating 1.000 times the LCOE at each price of EUA by using the increments of 1€. The dotted lines represent the 95% confidence intervals for CCS and REF IPPs.

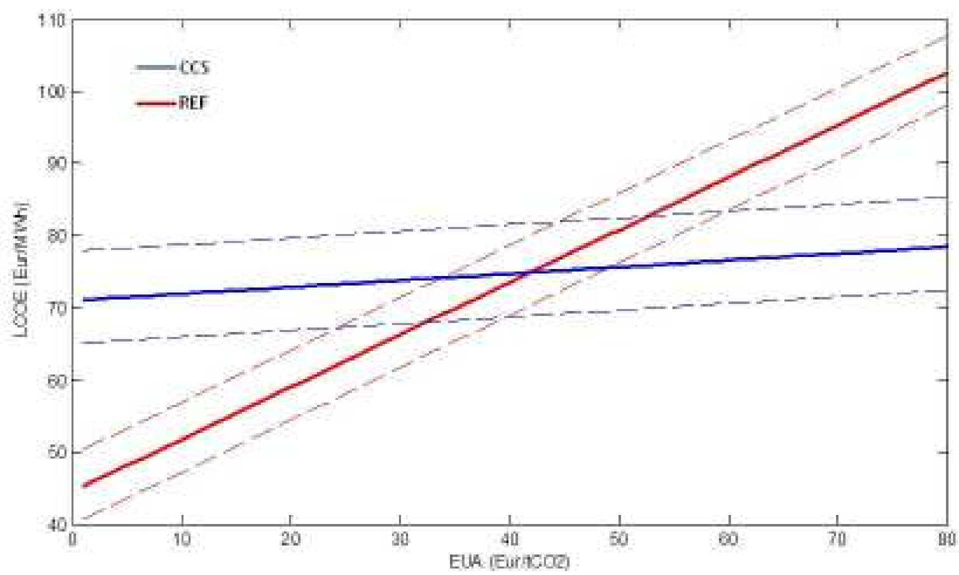

Figure 10. LCOE for REF and CCS dependent on different EUA

Our Monte Carlo simulations show that the most likely intercept (expected value) lies in the area around 40 €/tCO_2 and that represent the minimal price EUA should cost in order to make CCS technology competitive to non-CCS coal fired power plants in the EU.

4. Discussion

The baseline market scenario shows the LCOE intersection between IPP-REF and IPP-CCS at the EUA value of 46,25 €/tCO_2, which represent the cost of CO_2 avoided. The probabilistic approach presented in the paper investigates the economic performance beyond the classical deterministic and/or scenario based approach to evaluate the viability of coal-fired power plants. Our comparative study of power plant with and without CCS uses stochastic market variables (interest rate, price of fuel, CO_2 and electricity) assuming a predetermined probability density function. Our main finding is the mean value of financial breakeven point between IPP-REF and IPP-CCS (cost of CO_2 avoided) is 37,52 €/tCO_2 (90% probability space spanning between 34,59 and 40,64 €/tCO_2). A number of similar studies evaluating CCS performance obtained significantly higher values for EUA (**Lund et al, 2012**). We can accredit this significant difference, not only to the stochastic nature of the analysed market variables but also to the decreased cost of financing, decreased FOIK, as well as lower CCS transportation and storage costs. Marginal breakeven point (initial investment depreciated) between the two plants drops significantly to its mean value of 15,58 €/tCO_2 and 90% probability space spanning between 13,11 and 17,99 €/tCO_2. Although these EUA prices seem obtainable in medium term, they are still approximately 100% higher than the current market prices. Another significant variable determining the viability of coal-fired power plants and CCS technology is the market price of electricity. Given the low market prices of electricity on the main EU market there is a 26,9% probability of yielding a profit for IPP-REF and only 0,9% probability for IPP-CCS. At this points there is a very troubling situation in the EU where electricity prices are simply too low to stimulate investments in the energy generation sector in general as well as in the CCS technology. We can conclude that the CCS plants, with the current technology, electricity and

EUA prices cannot survive a free market competition with classical REF coal plants. For the CCS to become economically competitive either the market price of electricity or the price of EUA should significantly rise. Future research on this topic await operational, full-scale, CCS plants in EU and the availability of the data on technical and economic performance of CCS coal-fired power plants.

5. Conclusions

The EU is the leader in carbonless energy power system and an European IPP is obligated to adjust to that reality. Since coal is a widespread fuel in the energy power production, at present, it is not possible to secure a stable power system without coal power plants. Although they represent a significant step forward, coal power plants with CCS are not the final solution for carbonless power system, but they can provide the time necessary to develop new carbonless technologies. Because there is still no full scale power plant with installed CCS, which is fully operational, and which would give the exact answers to the real costs of the CCS, the objective of this paper is to create a model of the IPP-REF and IPP-CCS which would give a realistic answer in relation to economic viability of such projects and the role of EUA prices. To provide a more accurate determination of how much will the CCS add to the cost of the IPP-REF this paper has presented a clear link between fuel characteristic and emission costs. Our classical baseline scenario shows that at current price of the emission allowances it is not worth investing in the CCS.

In order to get a more realistic insight into the viability of IPP-REF and IPP-CCS we go beyond the classical deterministic or scenario based approach. We analyse the economic performance of IPP-REF and IPP-CCS by simulating the parametric estimates of relevant market variables (6-month Euribor, price of coal, EUA and electricity). Cost of CO_2 captured represents the breakeven point between IPP-REF and IPP-CCS since it gives the price of EUA certificates at which the financial performance of both plants would be equal. Mean value of cost of CO_2 captured is 37,52 €/tCO_2 (90% probability space spanning between 34,59 and 40,64 €/tCO_2), which is approximately five times higher than the current market price. Marginal cost of CO_2 captured shows the breakeven point excluding the investment costs. It shows what would be the breakeven point between the two IPP's in case both plants had their initial investment depreciated. In this case the required price of EUA needed to reach equilibrium drops significantly to its mean value of 15,58 €/tCO_2 and 90% probability space spanning between 13,11 and 17,99 €/tCO_2. Both the classical baseline scenario and simulation based, probabilistic, approach leads us to the same conclusion. IPP-CCS plants, with the current technology, cannot freely compete with the classical IPP-REF coal plants. For the IPP-CCS to become economically competitive either the price of EUA or the market price of electricity in the EU should significantly rise.

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