CO_2 Capture and Storage in the Greek Electricity Generation Sector

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ABSTRACT

The purpose of the work presented in this paper is to examine and evaluate the perspectives of application of CO_2 Capture and Storage (CCS) technologies in the Greek electricity generation sector, which is dominated by the utilisation of the domestic lignite resources. Results from thermodynamic simulations conducted within the framework of various EU-funded projects, both for green-field and retrofit applications of the oxyfuel technology and post-combustion capture with amine scrubbing in typical Greek power plants are used to demonstrate the potential for emissions reduction and evaluate the associated power output and efficiency penalties. The application of CO_2 capture technologies in a power plant is highly costly in terms of efficiency and net power output reduction. The thermodynamic data, coupled with the investment costs provide an insight on the economics associated to CO_2 sequestration options and the viability of the power plants within the framework of the application of a CO_2 economic penalty, in an electricity generation system based on low-quality coal. Finally, the discussion tackles the available CO_2 storage options and scenarios in the Greek territory, based on recent surveys for the assessment of CO_2 storage sites in Greece conducted within the framework of EU projects.

Keywords: CO_2 capture& storage, lignite power plants

1. INTRODUCTION

The Electricity Production balance in Greece was 53.4 TWh in 2005, reaching 56.9 TWh in 2008 for the interconnected system. The share of electricity productions sources in the Greek system is presented in Fig. 1, while Table 1 provides the installed capacity of the Greek power plants. Lignite plays an important role in the energy sector as it currently satisfies ca. 60% of the country's needs in electric power. Greek lignite is of low quality, characterised by low calorific value and high moisture content. The extraction of lignite takes place mainly in 3 regions of Greece, namely Ptolemais-Amynteo, Megalopolis and Florina. The annual production of lignite is around 65 million tons, of which 48 million tons derive from the coal fields of northern Greece (Ptolemais-Amynteo and Florina). Almost the entire lignite production is consumed in electricity generation, while small amounts of lignite are used for briquettes and other applications. Certain limited amounts of local lignite (xylitic type with high heating value between 12-16 MJ/kg) and imported coal, are used as additional fuels. Both coals are only required to support the combustion of the low rank lignite [1].

Greek lignite-fired power plants consist of six thermal stations using pulverised coal combustion conventional technology with a total capacity of 4,808 MWe. Over 10% of the installed power is generated by units which were constructed before 1970, while another 30%

corresponds to units aged from 20 to 30 years. However, Greek power plants are relatively younger compared to average European power plants, which have approximately 50% of their capacities in units of 13 to 20 years old. It is estimated that in 2010, approximately 37.5 % of the existing lignite-fired power plants, which produce 49.2 % of electricity in Greece, will reach 30 years of their operational life [1].

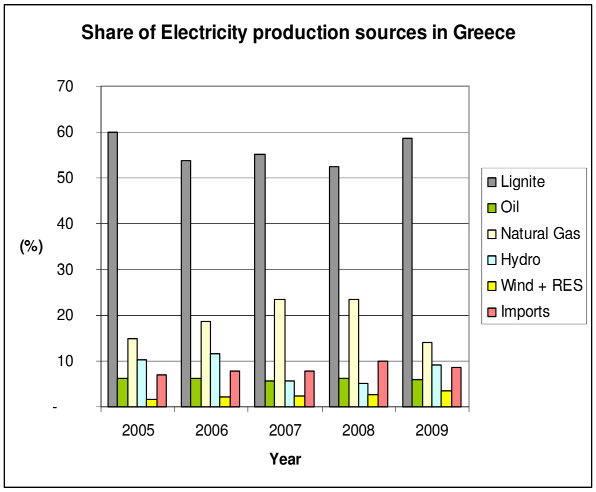

Figure 1: Share of electricity production sources in the Greek system (RES in HV grid)

Name	Units	Fuel	Installed Capacity (MW)	
Ag Dimitrios	5	Lignite	1,595	5,288
Amyntaio	2		600	
Meliti	1		330	
Kardia	4		1,250	
Ptolemaida	4		620	
Liptol	2		43	
Megalopoli I	3		550	
Megalopoli II	1		300	
Aliveri	2	Oil	300	750
Lavrio	2		450	
Komotini CCGT	1	Natural Gas	495	2,518
Lavrio CCGT	3		1,125	
Energy Thessaloniki CCGT	1		390	
Ag Georgios	2		360	
Herron I OCGT	3		148	
Hydro				3,017
Wind				676
Small Hydro				129
Biogas - Biomass				56
CHP - High Efficiency				28
PV				1

Table 1: Power Plants and installed capacity in the Greek system

Taking into consideration the forecasts for increase in the electricity demand over the coming years, the old and low-efficiency units should be either renovated or replaced by new units. The use of clean coal technologies in power plants can solve many emission problems, while specific measures to increase the efficiency of lignite-fired power units might include: identification of the loss sources of every unit, improvement of the cold end of the steam turbines, optimisation of the beater wheel mills operation, and the combination of natural gas-fired turbines with the existing boilers [1].

There is enough Greek low rank lignite to meet the demand of the electricity sector in terms of production and reserves, but lignite has to compete with natural gas, which has increased its share considerably in the electricity generation market during the past years, following the construction of the main gas pipeline network. The EC regulations on power plant emissions (Large Combustion Plant Directive - EC-LCP Directive - 88/609/EEC), coupled with the Kyoto Protocol and the European Commission and European Council proposals for the post-Kyoto period (revision of Directive 2003/87/EC for the improvement and expansion of the Emission Trading System of Green House Gases [23.1.2008 COM(2008) 16 final 2008/0013 (COD)], 23.1.2008, COM(2008) 18 final/ 2008/0015 (COD) regarding CO_2 storage in geological formations, revision of Directive 2001/80/EC for CO_2 capture ready units (> 300 MW)] raise obstacles for the firing of lignite. It must be shown that lignite produces low cost electricity in a environmentally friendly manner. Taking also into account the identified requirements for new units and renovation of old units, the use of Carbon Capture and Storage (CCS) technologies in lignite-fired power plants can help to eliminate these obstacles and solve emission problems. The current discussion will build upon the state of the art in CCS technological concepts for power plants and will be focused on the evaluation of the most promising identified technologies for lignite applications.

2. CO_2 CAPTURE AND STORAGE IN THE EUROPEAN MARKET

The development of novel electricity generation technologies aims at (near) zero CO_2 emissions, through Carbon Capture and Storage. The commercial or under development CCS technologies for thermal power plants are divided into three broad categories: CO_2 separation from flue gas (post-combustion capture), combustion in O_2 instead of air or oxyfuel combustion and production of a carbon-free fuel (pre-combustion capture) [2]. The European Technology Platform has estimated the effect of implementing the various CCS technologies in the European electricity generation sector in 2020, for typical natural gas, coal and lignite units [3]. The results are shown in Figures 2 and 3, in terms of electricity generation costs and CO_2 capture costs. An electricity generation cost increase of the order of 40-50% is marked when implementing CCS technologies, while the CO_2 capture cost per ton CO_2 is in the range of 50-60 €/t for solid fuel units and ca. 100 €/t for natural gas units, with a potential of decrease by 20-50% with further development of CO_2 capture technologies.

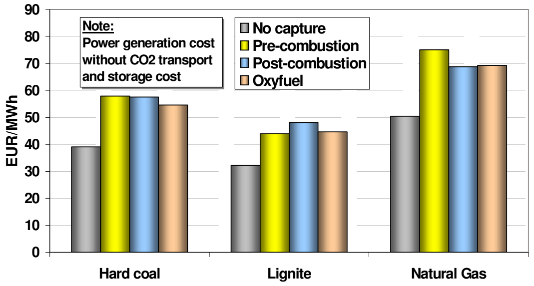

Figure 2: Estimated electricity generation cost from large coal, lignite and NG units in 2020, without and with CO_2 capture [3]

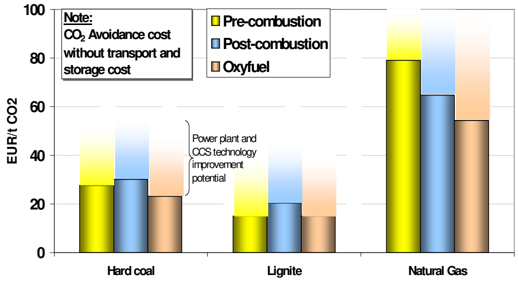

Figure 3: Estimated CO_2 capture cost from large electricity generation units in 2020 (coal, lignite and NG) [3]

According to the European Platform for Zero Emission Fossil Fuel Power Plants, a list of 43 large scale demonstration projects for CCS in Europe has been announced, while the first project implementation is foreseen for 2010. Among them, 6 projects are dealing with lignite utilization and CCS technology. All technological options are involved, while the most selected solution is post combustion [4]. Furthermore, according to the proposal of the Presidency to the European Council (20/3/2009) related to the European Economic Recovery Plan and call for proposals of May 2009, 13 CCS projects are to be funded with 1050 M€, of which 12 are dealing with coal utilization and include all technological options [5].

3. CO_2 CAPTURE AND STORAGE IN THE GREEK ELECTRICITY SECTOR

The current section aims to assess the effect from implementation of CCS technologies in the Greek electricity generation sector. In this respect, both a green-field oxyfuel power plant based on a typical Greek lignite-fired power plant as well as the retrofit of an existing lignite power plant to oxyfuel and post-combustion capture have been modelled, in order to demonstrate the potential for emissions reduction and evaluate the associated power output and efficiency penalties. The power plant simulations have been performed with the thermodynamic cycle calculation software ENBIPRO (**EN**ergie-**BI**llanz-**PRO**gram), a tool for heat and mass balance solving of complex thermodynamic circuits, calculation of efficiency and exergetic and exergoeconomic analysis of power plants, as well as the commercial thermodynamic cycle calculation software GATECYCLE.

3.1 Green-field Oxyfuel Greek Power Plant

The oxyfuel or O_2/CO_2 recycle combustion concept is based on the fact that when coal, hydrocarbon or synthesis gas is burned with pure oxygen produced by an air separation unit (ASU) instead of air, the produced flue gas contains mainly CO_2 and H_2O. By cooling the waste gas, the water content is condensed and an almost pure gaseous CO_2 stream can be achieved, which can be compressed, transported and stored. In order to lower the very high combustion temperatures produced when fuel is combusted with O_2, approximately 2/3 of the boiler exit flue gas mass flow should be recirculated in the combustion chamber [6], [7]. The main energy requirements for the O_2/CO_2 recycle combustion are the ASU power consumption, the compression of the final product for transportation/sequestration (110 bar), the consumption of fans for flue gas re-circulation and the CW pumps consumption for flue gas cooling/air inter-cooling at the ASU. The typical flue gas treatment for an oxyfuel power plant consists of the following steps: flue gas condensation with water treatment, compression (to transfer the flue gas in liquid state), active dehydration with Tri-Ethylene Glycol (TEG), heat exchanging, removal of non-condensable gases as N_2, O_2 and Ar and final compression to transport conditions [8].

The reference power plant used as a base case for the assessment of the efficiency of a Greenfield oxyfuel power plant is a 360 MWel gross power output plant with reheat and 7 water preheaters with steam extraction from the ST. Fig. 4 illustrates the process flow diagram of the reference case. Since the raw lignite has high moisture content, a fuel pre-drying system has been integrated in both the reference power plant and the oxyfuel plant, based on utilisation of the heat content of the moisture removed in the form of steam from the raw lignite, for the drying (WTA drying system) [9]. The water content of the raw lignite is 55.4 % w/w while it is reduced to 12 % w/w at the exit of the dryer. The ultimate analysis and LHV of the raw and dried fuel are shown in Table 2. In all simulations, the fuel consumption of the power plant is kept the same.

	Raw	**Dried**
H w%	1.5	2.9
S w%	0.4	0.8
O w%	8.7	17.2
N w%	0.6	1.1
Ash w%	15.0	29.5
H_2O w%	55.3	12.0
LHV (kJ/kg)	5,418	13,025

Table 2: Raw and dried lignite ultimate analysis

The basic aspects of the greenfield application of the oxyfuel technology are presented for a typical low rank coal power plant. Fig. 5 illustrates the process flow diagram of the plant. Several process integration options were identified for the greenfield oxyfuel power plant, and an "optimised" scenario has been investigated, integrating these options.

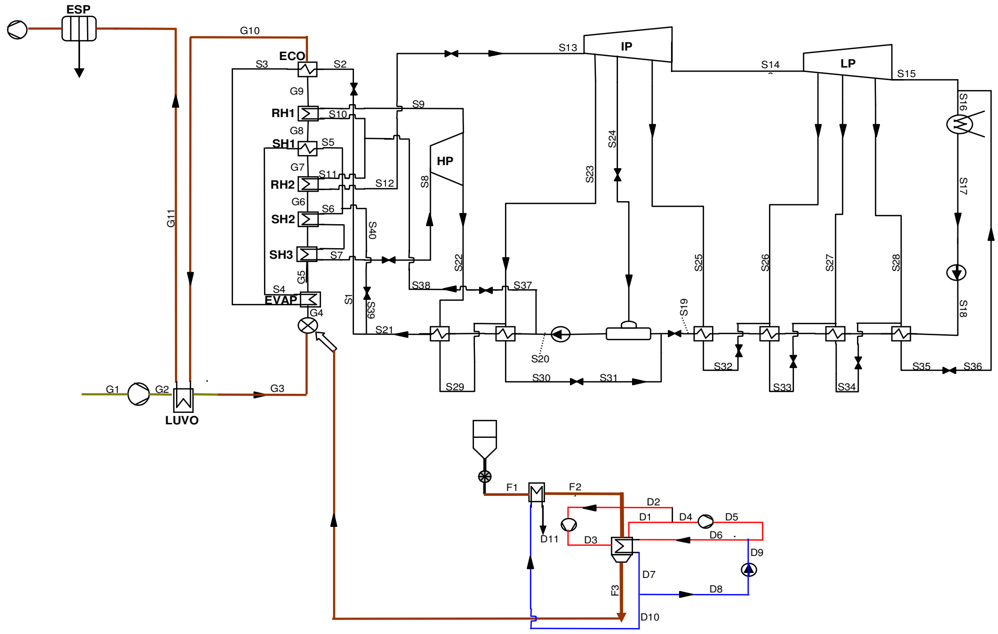

Figure 4: Reference power plant PFD

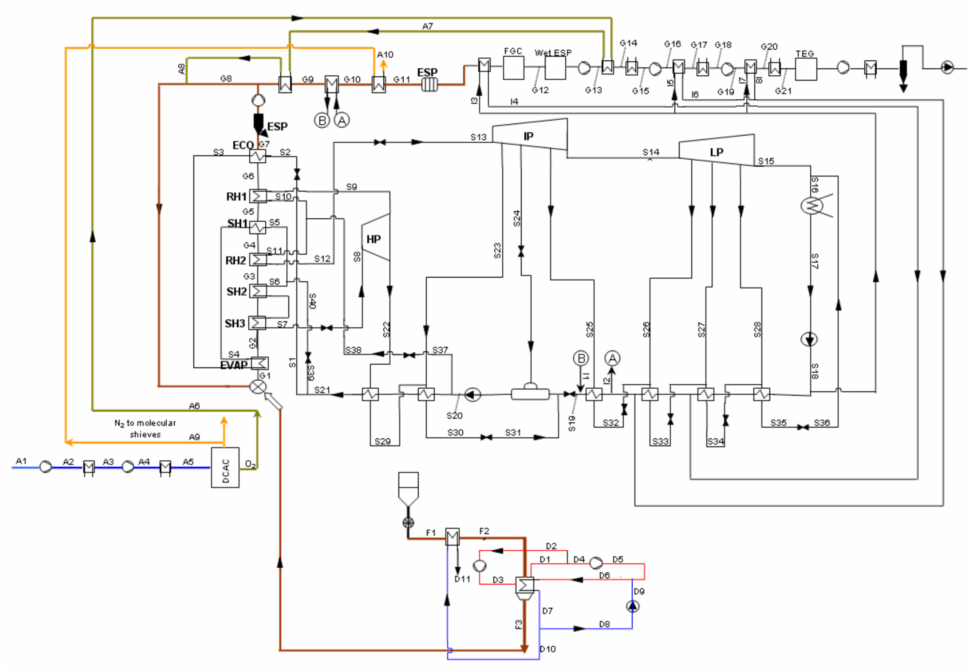

Figure 5: Greenfield oxyfuel power plant PFD

A cryogenic air separation Air Separation Unit (ASU) is used for oxygen production, which is the most suitable and commercially available technique for nitrogen separation from air. The cryogenic air separation process includes the following stages: air compression with intercooling, air cooling to 11.5 ºC, removal of water vapour and other impurities through molecular sieves, liquefaction of the compressed air (-180ºC) in a heat exchanger, utilising the heat of the outgoing gas streams and separation of N_2 from the liquefied air in a distillation column [10]. Up to 15% of the power plant's electrical output is consumed by the process

[11]. Taking into account the energy required for the air separation, the oxygen purity chosen for the study is 95 % vol (the remaining 5 % vol is mainly Ar and N_2) [6].

The excess oxygen applied in the oxyfuel case is 5%, while the air infiltration rate in the boiler and the ESP is 0.01 kg/ kg of flue gas. CO_2 compression is achieved in 5 stages, with intermediate cooling to 21 ºC, while air compression for the ASU occurs in 2 stages with intermediate cooling to 21 ºC.

When applying O_2/CO_2 recycle combustion, the air preheaters are not used, resulting in an increase of the flue gas exit temperature to ca. 310 ºC. A hot ESP is used for particle removal at the boiler exit. The flue gas recycle is extracted downstream the hot ESP and mixed with the O_2 stream from the ASU. The O_2 stream is heated from the remaining flue gas, which consequently follows a further particle removal process in a cold ESP. The molecular sieves are regenerated utilising dry N_2 from the ASU, heated by flue gas to 150ºC.

Heat from the flue gas condenser is integrated in the water steam cycle by partial replacement of low-pressure feedwater heaters 1 and 2. O_2 is heated from the 1st CO2 compression step up to 110 ºC. Heat from the 2nd and 3rd compression steps are used for water preheating at the LPH1, LPH2 and LPH3 water heaters. The flue gas that exits the boiler, before entering the flue gas treatment process line, is used for partial replacement of LPH4 water heater.

		Ref. PP	**Greenfield oxyfuel PP**
FW pump	MW_{el}	9.17	9.54
FD fan	MW_{el}	1.43	-
ID and gas fans	MW_{el}	2.77	3.55
Dryer	MW_{el}	25.21	25.21
Lignite mills	MW_{el}	9.05	9.05
ESP’s	MW_{el}	0.50	0.50
Fly ash transport	MW_{el}	0.85	0.85
Lignite feeding and handling system	MW_{el}	0.78	0.78
Condensate pumps	MW_{el}	0.54	0.56
Circulating and cooling water pumps	MW_{el}	3.74	3.93
Others	MW_{el}	1.14	1.20
ASU	MW_{el}	-	52.39
CO_2 compression	MW_{el}	-	46.35
Raw Fuel flow	kg/s	136.34	136.34
Gross power output	MW_{el}	356.78	392.45
Gross el. efficiency	%	48.30	53.13
Net power output	MW_{el}	301.61	238.53
Net el. efficiency	%	40.83	32.29

Table 3: Main results of the simulations [12]

The main results of the simulations, in terms of power output and efficiency, are presented in Table 3. A significant increase in gross power output for the oxyfuel PP was observed, in the magnitude of 36 MW. That is partially attributed to an increased steam production from the boiler, as well as to the heat integration scheme, which has eliminated the need of some steam extractions for preheating. Nevertheless, the significant demand for auxiliary power arising from the application of the oxyfuel CO_2 capture technology results in a considerable penalty in the power plant performance of ca. 8.5 percentage points. Concerning the CO_2 capture efficiency, this is strongly related to the flue gas composition at the boiler exit. The remaining non-condensable gases in the oxyfuel case consist of O_2, N_2,

SO_2 and Ar. Their presence is due to the 95% vol. purity of the O_2 at the exit of the ASU, as well as the air infiltration in the boiler and the ESP. The removal of non-condensable gases is achieved by a flash process and are released to the atmosphere. However, an amount of the condensed CO_2 is released too during this process [13]. The higher the content of the flue gas in non-condensable gases at the boiler exit, the lower the CO_2 capture efficiency. In the case examined, the calculated CO_2 capture efficiency is limited to 90% of the CO_2 produced from lignite combustion, according to the flash process simulated.

3.2 Retrofit of a Greek Power Plant with CCS

From the three basic CO_2 capture technological pathways, only post-combustion capture and oxyfuel combustion can be applied in existing power plants. In this framework, the retrofit of a typical 330 MWel power plant with amine scrubbing and oxyfuel combustion has been modelled. The plant has a supercritical boiler and a triple-pressure steam turbine configuration with 8 feed-water preheating stages. The flue gas after the air pre-heater passes through the electrostatic precipitaror and the flue gas de-sulphurisation unit.

The most commercially successful technique for CO_2 capture from power plants flue gases is the wet scrubbing process with chemical absorption by MEA. MEA scrubbing provides CO_2 recovery of 98% and product purity of more than 99%. Most systems use an aqueous solution of 15-25 wt% MEA, mainly due to corrosion issues [14]. In the amine gas processing operation, CO_2 is absorbed from the flue gas by the liquid solvent in an absorber operating at 40-60 ºC [14]. The gas stream and the liquid solvent are contacted in counter-current flow in the absorption tower. The gas to be scrubbed, after being compressed to ca. 1.3 bars, enters the tower at the bottom, flows up and leaves the absorber at the top. The solvent, enters the tower at the top, flows down and leaves at the bottom. In the stripper (regeneration stage) the charged amine solution is heated with steam to 120-150 ºC, in order to strip off CO_2 [2]. The hot lean amine solution flows through a heat exchanger, where it is contacted with the charged amine solution flow and then it enters again the absorption tower. The CO_2 stream is cooled, its water content is removed, and it consequently compressed and transported to the storage location. The main energy consuming processes concerning the amine scrubbing technology, for a 90% CO_2 capture rate, are the following:

- Heat consumption for regeneration of the rich-CO_2 solution (4 MJ/kg CO_2), covered by LP steam extraction from the steam turbine at 6 bar/285 ^oC (1.7 kg steam/kg CO_2) [15].
- Electricity consumption of flue gas blowers used to overcome the system pressure drop, as well as for pumping of the amine solution and of the absorber wash water [15].
- 5-stage compression of the CO_2 stream to 110 bar with inter-cooling to 20 ^oC for transportation and storage and cooling pumps consumption (inlet pressure 2.5 bar).

Under the assumptions of 95% O_2 purity and 3% air infiltration, the oxyfuel combustion process can capture 79% of the CO_2 that is produced from coal combustion [7], since the flue gas contains a significant amount of non-condensable gases (N_2, Ar και O_2) that should be removed. During the removal process, part of the CO_2 is vented to the atmosphere. The main energy consuming processes of the oxyfuel technology are the following:

- Cryogenic ASU: 4-stage air compression to 5.5 bar with inter-cooling to 20 ^oC.
- CO_2 compression: 5-stage compression 110 bar with inter-cooling to 20 ^oC.
- CW compression to 2.5 bar, for cooling of the ASU inlet air and of the CO_2 stream.

The main results of the simulations are presented in Table 4, where the large influence of integration of CO_2 capture technologies on the efficiency of the original power plant is demonstrated. The application of the oxyfuel and the amine scrubbing technology decreases the power plant efficiency by 10.3 and 11.5 percentage points, respectively. The oxyfuel technology has a greater optimization potential, since the flue gas exits the boiler at 305 ^oC, due to the elimination of the air preheater, and a large amount of heat could be recovered for feed-water pre-heating. Due to the increased cost and difficulty of this scheme for retrofit applications, the above mentioned solution can be applied mainly in new power plants with CO_2 capture, as has been shown in section 3.1.

		Original	**Oxyfuel**	**Amine**
Regeneration heat consumption	MW_{th}	-	-	256.5
ASU consumption	MW_{el}	-	58.1	-
CO_2 compressors	MW_{el}	-	22.4	20.5
CW pumps	MW_{el}	-	1.5	0.7
Absorber consumption (blower, pumps)	MW_{el}	-	-	8.7
Net power output	MW_{el}	293.7	211.0	200.5
Net efficiency	%	35.7	25.4	24.2
Power output decrease	MW	-	82.7	93.2
Efficiency decrease	%	-	10.0	11.2
Specific emissions	kg CO_2/kWh	1.075	0.31	0.17

Table 4: Basic retrofit simulation results

3.3 Economics of CO_2 capture in the Greek electricity market

In this section, an estimation of the electricity generation cost is provided for the following technologies: conventional lignite power plant, conventional lignite power plant with integrated CO_2 capture with amine scrubbing and oxyfuel combustion, state-of-the art supercritical lignite power plant (clean coal technologies), natural gas-fired combined cycle and IGCC power plant. For the calculations, the following assumptions have been made: discount factor 8%, inflation 3%, lignite cost 1.8 €/GJ and natural gas costs 5.5 €/GJ, depreciation for solid fuel units 25 years, for NG and IGCC units 15 years. The operating and maintenance costs is assumed 3% of the investment cost per year and the variable costs 0.01 €/kWh for lignite units and 0.005 €/kWh for natural gas units. The annual operating hours of the units are 7500 at full load. The CO_2 cost, defined by the CO_2 market, has been assumed 18 €/tn. The specific assumptions for each power plant case are provided in Table 5 [2].

		Convent. lignite fired power plant	**Amine scrubbing**	**Oxyfuel**	**Clean coal**	**NGCC**	**IGCC**
Net power output	MWel	293.7	200.5	211	300	380	766
Net efficiency	%	35.4	24.2	25.4	44.0	56.5	43.0
Investment cost	€/kW	1100	1900	1570	1150	600	1370
CO_2 specific emissions	kg/ kWh	1.075	0.17	0.31	0.865	0.37	0.76

Table 5: Specific assumptions for electricity generation cost estimation

Fixed costs include the capital cost depreciation and the operating and maintenance costs, while variable costs include the fuel cost. The natural gas-fired unit demonstrates the lowest fixed cost, due to its low capital cost while, on the other hand, for the units with CO_2 capture and the IGCC unit, the fixed costs are a large percentage of the total kWh costs, due to the increased capital, operating and maintenance costs. Because of the low fuel costs, lignite units have the lowest variable costs with respect to natural gas units. Nevertheless, the variable costs of units integrating CO_2 capture increase significantly, due to their low efficiency. The increased volatility of natural gas price, due to its dependency to oil prices (up to 40% of total costs [16]) contributes in an increased uncertainty concerning the electricity generation cost from natural gas-fired combined cycle units, in contrast to the domestic lignite market which is practically independent of oil prices.

For the estimation of the effect of CO_2 emissions on electricity generation costs, the units have been grouped in two categories: current technologies and technologies that will be commercially available in the future. The difference in specific emissions from the reference unit for each category (natural gas unit for the first category and conventional lignite power plant with integrated CO_2 capture with amine scrubbing for the second) multiplied by the CO_2 cost is an estimation of the price risk due to the emitted CO_2.

As concerns the total generation costs, Figures 6 7 show that the conventional lignite power plant, the state-of-the art supercritical lignite power plant and the IGCC unit have the lowest kWh costs, while the natural gas unit has the highest generation cost, due to the high fuel prices and the market uncertainty. In addition, the implementation of CCS technologies significantly increases the capital costs and influences negatively power plant efficiency and, as a result, electricity generation costs.

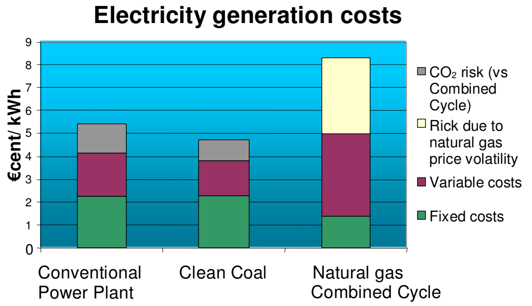

Figure 6: Electricity generation costs - Current technologies

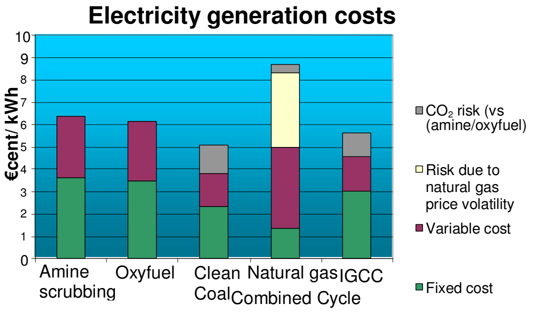

Figure 7: Electricity generation costs - Future technologies

3.4 Storage capacity of geologic formations in the Greek territory

The candidate geologic formations where CO_2 could be stored in the long term are mostly present in Northern Greece. These formations are a part of the Mesohellenic Trough, of the Thessaloniki basin and of the Prinos basin. The total storage capacity is estimated to ca. 2345 Mt CO_2, as presented in Table 6. The locations have been selected due to their proximity to the main sources of CO_2 emissions, namely the lignite-fired power plants situated in Northern Greece, refineries, cement and fertilizer industries. Especially the Prinos basin offers adequate infrastructure, due to the exploitation of hydrocarbon resources conducted in the area. Nevertheless, further research is required for all the candidate areas so that their suitability is confirmed.

Aquifer	**Location**	**Storage Capacity (Mt CO_2)**
Prinos	offshore	1343
W. Thessaloniki	onshore	459
W. Thessaloniki sandstone	onshore	145
Alexandria	onshore	34
Mesohellenic basin	onshore	360
Total		2345

Table 5: CO_2 storage potential in Greece [17]

4. CONCLUSIONS

CCS technologies can contribute significantly in the reduction of atmospheric CO_2 emissions from the electricity generation sector. Nevertheless, the effect of implementation of these technologies in the efficiency decrease of the power plants is pronounced, resulting in a considerable increase of electricity generation costs, in combination with the higher investment costs. In addition, the purchase of CO_2 credits through the CO_2 market under development is expected to further increase electricity costs. From the comparison of the various technological solutions, it is concluded that units utilising local lignite can under these circumstances have a competitive kWh cost with respect to natural gas units, which present a larger cost risk due to the volatility of natural gas prices.

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