Modelling of a carbon capture and storage system for the Latvian electricity sector

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Abstract: Implementation of carbon capture and storage (CCS) technologies with the aim to minimise carbon dioxide emissions in the atmosphere has a significant influence on the national energy sector both from an economic and environmental point of view. Because of economic and technological considerations, the EC Directive on Carbon Capture and Storage determines the obligations only for operators of combustion plants with a rated electrical output of 300 megawatts to ensure the CO2 capture and storage possibilities from 2015. This paper provides a cost analysis for six power plant scenarios with CCS for coal, natural gas and biomass combustion and capture technologies. The results of the paper show the CO2 reduction potential from 2015 to 2020 and changes in the cost of electricity related to the introduction of CCS.

Key-Words: energy modelling, carbon capture and storage, electricity production costs, avoided CO2

1 Introduction

The integration of carbon capture and storage technologies into the energy production sector presents a challenge for the stabilization and limitation of the concentration of CO2 in the atmosphere. Policy requirements are usually considered as strong enforcement instruments for the implementation of new techniques. In this case, the European Union has developed and enforced the policy framework for CO2 capture and storage: Directive on Carbon Capture and Storage, Integrated Pollution Prevention and Control Directive, the European Emission Trading Scheme, etc.

The main objective of the research described in this paper was to develop the cost analysis of integration of full cycle carbon capture and storage (CO2 capture and compression, transportation, injection and storage) into the Latvian energy sector and fit it into the existing methodology for energy tariff calculations. The cost analysis includes actions towards the minimization of greenhouse gas emissions stated in the European Union climate and energy package.

2 General concepts of carbon capture and storage economics

2.1 Capture principles

Carbon dioxides can be captured from flue gases using different methods. The amount of CO_2 that can be removed from the exhaust depends on the size of the absorption unit and the concentration of CO_2 in the exhaust: the economic recovery limit is approximately 85% for 3% CO_2 in the exhaust and 90-92% for 8% CO2 concentration in the exhaust [1]; to assure with absorption method the concentration of captured CO2 in the range of 80 – 95 %, the energy requirements are 4,5 - 5,5 GJ per tonne of CO_2 [2].

Energy consumption for regeneration depends on the type of solvent and concentration of CO2 in the exhaust: regeneration of MEA-type absorption solvent for flue gases (15% concentration of CO2) from coal firing technologies requires 3,2 GJ/tCO_2 and for flue gases from natural gas combustion (3% concentration of CO2) - 3,7 GJ/tCO_2 [3].

Solvent consumption (different for various solvent types) sets the second type of costs associated with the CO2 absorption method: the average solvent consumption is in the range of 0,2 - 1,6 kg/tCO_2 [4], the highest price level relates to the MEA solvent type. The type of solvent also defines the amount of chemicals used to reclaim the amines heat stable

salts (typically 0.03–0.13 kg NaOH/tCO2) and to remove decomposition products (typically 0.03 - 0.06 kg activated carbon/tCO2) [5].
The costs for absorption processes of CO2 mainly relate to regeneration options of the solvents (80% of extra energy consumption are required for regeneration). The extra energy consumption also needs to be taken into account using membranes where the energy is directly spent to capture CO2 - overtaking pressure difference between two parts of the membrane [3].

2.2 Transportation via pipelines principles

To ensure CO2 transport via pipelines, CO2 captured in the energy plant must conform to specific kinetic and physical conditions. Therefore in the capture process or between the capture and transport units, the CO2 flow is treated according to the needs of a specific pipeline: usually compressed in compressors or pumps to a set pressure [6].
Investment costs of the pipeline system development contribute to pipeline geometric parameters - length and diameter [6,7]. Additional costs may occur because of the specific topography of a pipeline laying site and materials of the inner and outside coatings of pipes (HDPE, PA11, PVDF, PEX type elastomers are used to minimise the corrosion and friction factors of CO2 pipes) [8].
The average costs for the whole CO2 transport chain via overland pipeline are 0,02Euro/tCO_2/km [1], incl. 5 - 6% operation and maintenance costs (O&M) where the environmental costs, maintenance and operation of the transport infrastructure issues and modernization costs are included. Bock et al. [9] report that the O&M costs of operating a 480 km CO2 pipeline on an annual basis amounts to approximately 2290 Euro/km per tonne of CO2. Thus, for a 100 km long pipeline, transporting approximately 5 million tonnes per year of CO2 with no booster pumping stations, the O&M costs would account for approximately 6% of the total cost per tonne of CO2 [10].

2.2 Storage principles

The main potential for captured CO2 is CO2 storage. Potential storage sites for CO2 are: deep sea sediments, depleted oil and gas reservoirs, unminable coal seams, saline aquifers and mineral carbonation [5]. In the case of Latvia, the most suitable geological formations for CO2 storage are saline aquifers: there are more than 10 potential saline aquifer reservoirs all over the country [11].
The depth and geological conditions (permeability, density of the effective storage layer, etc.) of the storage site have a significant effect on the total storage costs: geological survey, development of injection wells, construction of platform and development of pipeline and pump system, as well as CO2 injection costs (incl. extra energy consumption costs for injection) constitute up to 80 – 90 % from the total storage costs [1]. The costs associated with monitoring the storage site vary from 10-20% of the total costs [1] or 0,07 - 1 Euro per stored tonne of CO2 [5].

3 Methodology

The cost analysis of the implementation of a full cycle (CO2 capture and compression, transport, injection and storage) CCS is performed for an electricity production plant (300 MWe, 7000 working hours/year) planned to be built in Latvia and various fuel types, energy generation technologies, as well as capture technologies are modelled. The following scenarios are proposed for the cost analysis:

- natural gas combined cycle technology with post combustion MEA solvent capture (hereinafter GTKC P-MEA);
- natural gas combined cycle technology with chemical looping combustion capture (hereinafter GTKC O-CLC);
- pulverized coal combustion with pre-combustion MDEA solvent capture (hereinafter PCC P-MEA);
- coal gasification combined cycle technology with pre combustion MDEA solvent capture (hereinafter IGCC Pre-MDEA);
- biomass-fired plant based on a steam turbine technology with post combustion MEA solvent capture (hereinafter BTT P-MEA);
- biomass - fired cogeneration plants based on an integrated gasification combined cycle technology with pre-combustion MDEA capture (hereinafter BIGKC Pre-MDEA).

For all the scenarios it is assumed that (1) captured CO2 is compressed and transported to the saline aquifer storage site via pipelines; (2) the distance between the CO2 source and storage site is 100 km; (3) the diameter of the pipeline used is 0,40 meters; (4) the injection depth is 1000 meters; (5) one injection well is used to inject CO2 into the geological reservoir; (6) the price of CO2 allowance is 40 Euro/tCO2. Table 1 provides the variable technical data of the analysed scenarios.

Table 1. Description data of the analysed electricity costs models

	PCC	IGCC	GTKC	GTKC	BTT	BIGKC	Reference

	P-MEA	Pre-MDEA	P-MEA	O-CLC	P-MEA	Pre-MDEA	
Efficiency factor, %	30 – 40	35 – 37	43 – 50	50 – 54	14 – 30	25 – 37	[4, 5, 13-20]
Capture efficiency, %	85 - 90	92 – 96	85 – 90	97 - 100	85-90	44 – 90	[4, 5, 13, 15-17, 19-23]
$I_{capex,en./kWe,}$ Euro/$kW_{e,uzs}$	1454 - 2804	1651-2400	527-1300	691-1466	2304-3584	1224-2200	[4, 13-16, 19, 20, 22]
$I_{O\&M,en./kWe,}$ Euro/$kW_{e,uzs}$	84-159	83-94	21-49	36-67	79-147	80-117	[13-16, 18-19]
CO2 emissions stored, MtCO2/year	1,28 - 1,34	1,33 – 1,46	0,44 – 0,62	0,63 – 0,71	4,17 – 5,75	3,55 – 4,90	
Fuel price Euro/t, m^3, solid m^3	77,64	77,64	345,73	345,73	29,26	29,26	
Fuel emission factors with CCS, tCO_2/GWh_k	32	32	22	22	- 397	- 397	[23]

The principles of CCS have already been integrated into the European Emission Trading scheme. Accordingly, the following assumptions are taken into account in the analysis:

- the number of CO2 allowances received by coal and natural gas power plants which implements carbon capture and storage will be equal to zero, this means that all the emissions produced by the plants will be successfully stored in geological storages;
- the number of CO2 allowances received by biomass power plants which implement carbon capture and storage will be equal to the tonnes CO2 stored in the geological storage, resulting in energy products with negative net atmospheric carbon emissions. The income obtained from the CO2 allowances trading will be feed into the electricity tariff.

The capital investment costs and O&M costs are included in the electricity tariff calculation directly – the electricity calculation algorithm for a standard power plant is added with CCS characteristic components for capital and O&M costs. Extra energy consumption (needed for CCS process implementation) is integrated into the algorithm through a decrease of the total energy efficiency factor. Thereby the costs analysis of CCS technologies includes the following cost components: capital investments, energy production costs (incl. CCS introduction, operation and maintenance (O&M) costs), specific costs of avoided and captured CO2 – costs needed to capture 1 tonne of CO2 from flue gases and to avoid from emitting into the atmosphere 1 tonne of CO2. The avoided emissions are calculated as the difference between the emissions (tCO2 per produced electricity kWh) produced by the power plant without CCS and the same power plant with CCS [9]. Thus it becomes clear that the definition of a standard scenario (without CO2 capture) is indispensable to this assessment. Rather the cost per tonne of avoided CO2 has to be calculated. Calculations for each CCS stage, i.e. CO2 capture and compression, injection and storage are conducted separately.

3.1 Calculation of capture, compression and pumping costs

CO2 capture costs build up to 70% of the full cycle CCS costs [1, 5, 6] and include investment costs for the development of the capture unit and O&M costs of the unit, incl. costs for extra fuel consumption to compensate energy consumption used for capturing [13].

$$C_e = f(C_{capex,f}, I_{O\&M,f}, CRF, PF, FCF, P, h, C_k) \tag{1}$$

where
C_e – electricity cost, Euro/kWh;
$I_{O\&M,v}$– variable O&M costs, Euro;
$C_{capex,f}$– fixed investment costs, Euro;
CRF - capital recovery factor;
FCF – fuel conversion factor, kJ/kWh;
PF – energy plant power factor, %;
P – installed capacity, MW;
h – operation hours, h;
C_k – fuel price, Euro/kJ.

An additional component often included into the CO2 capture phase is CO2 compression before transportation firstly to change the aggregative state of CO2 from gas to liquid; and secondly to reach the technically and economically optimal CO2 flow conditions suitable for CO2 transport via pipelines.

$$Cc = f(m, m_{unit}, N_{train}, P_{cr.}, P_1, P_{tr}, \rho, \eta_s) \tag{2}$$

where
C_c – capital costs of the compressor(s), Euro/kW;
m – CO_2 flow rate, t/day;

m_{unit} – CO_2 flow per each compression unit, kg/s;
N_{train} – number of parallel compressor trains;
P_{cr} – critical pressure of CO2, MPa;
P_1 – initial CO_2 flow pressure, MPa;
P_{tr} – pressure of CO_2 transport, MPa;
ρ – CO_2 density, kg/m^3;
η_s – pump energy efficiency, %.

The operation and maintenance costs (O&M) of the compression are calculated with O&M factor.

$$C_{O\&M,compr.a..} = C_{,total} \cdot O\&M_{factor} \qquad (3)$$

where
$C_{O\&M,compr.a.}$ – annualized O&M costs of the compression phase, Euro/kW/year;
C_c – total costs of the compression phase, Euro/kW;
$O\&M_{factor}$ – O&M cost factor.

Therefore the difference in the costs results from the change of the CO_2 mass flow rate, the CO2 initial pressure and CO2 transport pressure.

3.2 Calculation of transport costs

Compressed CO2 flow is transported via pipeline to the storage site. As was stated before, the distance between the compression unit and the storage site observed in the research is 100 km.
By this time the CO2 transportation via pipelines is well researched area because of the existing technical similarities of transportation of oil products/ natural gas and carbon dioxide and different cost models for calculation of the CO2 transport via pipelines are available also in [6, 7, 10]. In the research the calculation of the CO2 transport costs is based on several methodologies: McCollum model, Ogden model, MIT model, Ecofys model, IEA GHG 2005/3 report model and Cobb – Douglas model [6, 7, 10]. This combined calculation method is chosen to get that various pipeline structure and landing parameters are included in the cost model at the high degree of detailed elaboration. According to this, the CO2 transport costs model combines the existing models in the form of mathematical series (see Formula 4) and the results are shown as a minimal and maximal cost level range might be reached for the scenario.

$$C_{(TR)} = \frac{MIN \vee MAX(C_{tr1}, C_{tr2}, C_{tr3}, C_{tr4}, C_{tr5}, C_{tr6})}{10^6} \qquad (4)$$

where
$C_{(TR)}$ – the CO2 transport cost, million Euro/year;
MIN $\vee$ MAX – range of minimal or maximal cost values for the CO2 transport;
C_{tr1} – the CO2 transport cost acc. to McCollum model, Euro/year; [6]
C_{tr2} – the CO2 transport cost acc. to Ogden model, Euro/year; [6]
C_{tr3} – the CO2 transport cost acc. to MIT model, Euro/year; [6,24]
C_{tr4} – the CO2 transport cost acc. to Ecofys model, Euro/year [7];
C_{tr5} – the CO2 transport cost acc. to IEA GHG 2005/3 model, Euro/year [7];
C_{tr6} – the CO2 transport cost acc. to Cobb-Douglas model, Euro/year [8].

The technical parameters (pipeline type, length, roughness, diameter, etc.) are equal to all the scenarios; however the CO2 mass flow is distinctive for each capture method and fuel used for energy generation.

3.2 Calculation of injection and storage costs

It is assumed in the research that the CO2 is injected into the saline aquifer located in the western part of Latvia (the geological parameters of the reservoir is taken into account in the calculations) and corresponds to the mid-continental region acc. to McCoy [10]. The injection depth is 1000 meters and one injection well is used to transport the CO2 into the storage reservoir. The calculation model is based on two existing models and corresponds to the algorithm used for CO2 transport cost calculation (see Formula 4).

$$C_{(st)} = \frac{MIN \vee MAX(C_{st.1}, C_{st.2})}{10^6} \qquad (5)$$

where
$C_{(st)}$ – injection and storage costs, million Euro/year;
MIN $\vee$ MAX - range of minimal or maximal cost values for the CO2 injection and storage;
$C_{st.1}$ – the CO2 injection and storage costs acc. to McCollum model, Euro/year [6];
$C_{st.2}$ - the CO2 injection and storage costs acc. to Sean T. McCoy (2008), Euro/year [10].

4 Results and discussions

4.1 The electricity cost results

In case of CCS implementation, electricity production from the biomass remains the most profitable. There is a 4 – 47 % electricity cost decrease for the BIGCC Pre-MDEA model and an up to 33 % decrease for the BTT P-MEA model. The electricity costs decrease when additional costs of CCS do not exceed the income from selling the free CO_2 allowances. The minimization of electricity cost becomes possible when CCS implementation costs do not exceed the expenses for CO_2 allowances in the case of standard electricity production.

The BIGCC Pre-MDEA model provides full compensation of the CCS implementation costs because of low conversion efficiency factors (14 – 30 %), however the amount of fuel used and CO_2 emissions generated are higher. In turn, high CCS costs of the BTT P-MEA model (approximately three times higher than the BIGCC Pre-MDEA model has) cannot be compensated at the maximal level of the cost diapason by trading free CO_2 allowances and therefore an increase of the electricity cost for 11% appears. It was calculated that the full compensation is possible if the price of CO_2 allowance is 49 Euro/tCO_2 in place of 40 Euro/tCO_2.

The increase of the CO_2 allowance price provides additional motivation to implement CCS. If biomass is used CCS implementation would produce more profit from electricity production. At the same time, the increase of the CO_2 allowance price would force electricity producers who use fossil fuel to switch to another fuel or to integrate CCS technologies to eliminate the amount of CO_2 allowances which must to be purchased. The critical range of the CO2 allowance prices (minimal and maximal values) are defined for the fossil fuel models (PCC P-MEA, IGCC Pre-MDEA, NGCC P-MEA and NGCC O-CLC). The CO_2 allowance price range shows the limits when it is more profitable to capture CO_2 rather than pay for the produced CO_2 emissions. The results of the CO2 allowance price range and the electricity prices for technologies with CCS are given in Table 2.

The compensation of the CCS system is better for the coal combustion technologies, which is argued by the higher concentration of CO2 in the fuels. The minimal electricity costs at the level of 84 Euro/MWh$_e$ for PCC P-MEA technology and 81 Euro/MWh$_e$ for IGCC Pre-MDEA might be reached after implementation of CCS for the coal fuel models. The CO_2 allowance price equal to 40 Euro/tCO_2 (reference scenario) does not provide full compensation of the CCS costs in the natural gas models. Because of the relatively low emission factor of natural gas, CO_2 allowances expenses are also relatively low in the natural gas models and give just partial compensation of the CCS costs.

Circumstances of the cost formation should be taken into account to compare the electricity cost results of different models which include: the fuel type, the system of electricity generation, and CO_2 capturing method. The following grouping of the analyzed models is reasonable:

1) *Use of different capture methods to the same electricity production system in case the same fuel type is used (the NGCC technology with P-MEA and O-CLC).*

The electricity production costs using CCS change in proportion to the capital costs of used CCS methods (according to the Table 2 data annual CCS costs for the NGCC P-MEA and NGCC O-CLC models are 44 - 63 million Euro and 36 - 70 million Euro). There is a 1 – 8 % and a 1 – 20 % increase for the mentioned models, respectively. Taking into account that the electricity costs at the minimal cost range border are the same but the capture possibility of the O-CLC method is more effective, it is more efficient to use the NGCC O-CLC model instead of the NGCC P-MEA.

2) *Use of one capture method in the different electricity production systems (P-MEA method implemented in the PCC, NGCC and BTT systems).*

Electricity production with the P-MEA method changes in different electricity production systems. The biomass BTT system has the highest cost of P-MEA implementation (135 – 169 million Euro/year). A three times smaller implementation cost is in the NGCC system (44 - 62 million Euro/year). P-MEA implementation to the PCC system costs 60 - 121 million Euro per year.

Despite of the huge P-MEA implementation costs in case of the BTT system, it is also possible to achieve the minimal electricity cost (63 Euro/MWh$_e$ for the minimal cost level). However, the biggest electricity cost appears in the natural gas fuel model despite that it has the smallest P-MEA implementation cost. This makes it clear that the costs of certain capture do not put affect the electricity cost formation. The benefits received from of the CO_2 allowances system must be evaluated as a priority.

3) *Use of the same capture method for the same energy generation system in case different fuels are used (Pre-MDEA method in coal and biomass IGCC system).*

The impact of the fuel type on the electricity cost and cost of the certain capture method could be analyzed in this situation. Pre-MDEA implementation into the biomass system produces the highest profit. In both cases, the decrease in electricity cost appears because of trading CO2 allowances. It is important to remember that the CO2 allowance trading mechanism differs for different fuel types. As a result, electricity production in the biomass model (BIGCC Pre-MDEA) is cheaper. It is possible to conclude that the price of electricity production in a system where CCS is implemented greatly depends on the fuel type used.

As a result of the electricity cost calculations, the cost formatting factors were considered. The correlation between the fuel emission factor: the greater the emission factor, the better and cheaper CO2 capturing is conducted, and the bigger amount of CO2 is avoided. Calculations also show that the price of the fuel used for energy generation correlates with the electricity costs of the full CCS cycle. In biomass models, the growth of the efficiency factor causes a decrease in the part of CCS costs which could be compensated by trading the free CO2 allowances, and the electricity cost, thereby increases.

4.2 Cost of CO2 avoidance

The calculation of costs of CO2 avoidance makes it possible to compare the economic efficiency of the whole CCS system and compare different alternatives.

The calculation results shows that natural gas models have the biggest CO_2 costs per tonne. The lowest CO_2 costs per tonne are achieved in the biomass models. CO_2 costs per tonne depend on the total costs of CCS implementation and the amount of CO_2 emissions captured/avoided relies on the emission factor value. The captured CO_2 costs per unit increases in proportion to the total costs of CCS, if the emission factor is constant (the fuel type is the same: PCC P-MEA and IGCC Pre-MDEA). When models with different fuel types are compared (PCC P-MEA and NGCC P-MEA) it becomes obvious that the captured CO_2 costs per tonne are lower when the emission factor is higher (see Figure 1), as far as technologically it is easier to remove the high concentration of CO2 from flue gas and the capturing system therefore is less expensive. The PCC P-MEA model has, on average, a 40 % higher annual CCS cost, and the emission factor of the coal model is higher. As a result, the captured CO_2 costs per unit are ~ 34 % lower in the PCC model.

Table 2.Costs of implementation of CCS

	Capture	Transport	Injection & Storage	Critical ranges of the CO2 allowance, Euro/t CO_2
PCC P-MEA, Euro/tCO_2 avoided	43-87	0,03-4,6	0,30 - 1,86	39 - 80
IGCC Pre-MDEA, Euro/tCO_2 avoided	29-46	0,19-4,6	0,14 - 1,90	26 - 46
NGCC P-MEA, Euro/tCO_2 avoided	71-121	0,03-7,43	0,40 – 4,30	54 - 100
NGCC O-CLC, Euro/tCO_2 avoided	49-101	0,03-6,14	0,40 – 3,30	46 - 87
BIGCC Pre-MDEA, Euro/tCO_2 avoided	10-20	0,01 – 2,43	0,1 – 1,00	n/a
BTT P-MEA, Euro/tCO_2 avoided	24-29	0,01 - 1,71	0,06 - 0,60	n/a

The biomass models are the most profitable if the avoided CO_2 tonne is considered. It is assumed in the analysis that the CO2 produced from biomass combustion is absorbed in the photosynthesis process. The emissions captured under the CCS are observed as avoided additionally. The calculations show that 90 – 96 % of the total CCS costs refer to the capture phase and are slightly dependent on the capture technology used for removal of the CO2. The negligible differences for the CO2 transport costs between the technologies occur because of the CO2 transported (different for each of the scenario). Allocation on type of fuels used (coal, natural gas or biomass) demonstrates that avoidance of the CO2 emissions from the atmosphere from biomass combustion makes it possible to reduce the cost of implementation of the CCS on account of the CO2 emission trading: the bigger amount of CO2 is avoided (in both ways- photosynthesis and capture and storage), the bigger incomes from emissions trading received. However the assumption of the double effect from the biomass combustion with CCS must be reviewed additionally (at technical and legal basis) in the future to minimize the risks of double counting of CO2 emissions avoided.

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