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EXECUTIVE SUMMARY

The aim of this case study is to give an overview of the CCS Project currently being evaluated for Bełchatów- the biggest lignite fired power plant in Poland. The project consists of three phases: CO₂ capturing, transportation and storage in aquifers located within a range of 100 km from Bełchatów.

Construction of an 858 MW generating unit in Bełchatów has been finished. On June 10 2011 after finishing electrical tests, the new 858 MW unit in Bełchatów was synchronised for the first time with the national power grid and on June 30 reached its maximum capacity of 858 MW. The process of optimising the operation of the unit's system is being continued.

It means that the national electricity power system received the first volumes of electricity from the newly built power unit at Bełchatów Power Plant.

1/3 of flue gasses is planned to be processed in order to remove carbon dioxide. For this unit wet amines capturing technology has been selected as the most suitable for post combustion gas processing method.

The report gives a short description of the Polish electricity industry and presents a problem with pollutions emissions. In 2008 the total Polish power plants CO₂ emissions amounted to **115 395 235 tonnes**.

Next part of the chapter discusses the available capture technologies, then it goes into the detailed description of the wet amines technology and gives ideas how the capturing plant will be introduced into the whole electricity generation process.

Then the report deals with geological works for potential storage locations and gives basic assumptions of sinks' capacities.

Further part presents problems connected with CO₂ transport to the storage locations. Possible transport methods as well as risks incurred are shortly mentioned.

Last part of the report presents some economic facts connected with investments and operations of the capturing plant in different time horizons.

The total CO₂ capturing and storage costs are shown in the table below.

	Time of the experiment		
2010 prices	10	15	20
PLN/tonne of CO ₂	245.03	216.85	203.79
EUR/tonne of CO ₂	62.83	55.60	52.25

The numbers in the table show that the impact of CCS on electricity prices will be significant- from 50 to 60 EUR per 1 MWh (assuming 100% CO₂ captured from flue gasses).

PROJECT SUMMARY

The CO2Europipe project aims at paving the road towards large-scale, Europe-wide infrastructure for the transport and injection of CO₂ captured from industrial sources and low-emission power plants. The project, in which key stakeholders in the field of carbon capture, transport and storage (CCTS) participate, will prepare for the optimum transition from initially small-scale, local initiatives starting around 2010 towards the large-scale CO₂ transport and storage that must be prepared to commence from 2015 to 2020, if near- to medium-term CCS is to be effectively realized. This transition, as well as the development of large-scale CO₂ infrastructure, will be studied by developing the business case using a number of realistic scenarios. Business cases include the Rotterdam region, the Rhine-Ruhr region, an offshore pipeline from the Norwegian coast and the development of CCS in the Czech Republic and Poland.

The present report describes a CCS project in Poland, one of the business cases considered in the CO2Europipe project. Another report, D4.4.1, describes the environmental impact assessment for the same CCS project.

The project has the following objectives:

1. describe the infrastructure required for large-scale transport of CO₂, including the injection facilities at the storage sites;
2. describe the options for re-use of existing infrastructure for the transport of natural gas, that is expected to be slowly phased out in the next few decades;
3. provide advice on how to remove any organizational, financial, legal, environmental and societal hurdles to the realization of large-scale CO₂ infrastructure;
4. develop business case for a series of realistic scenarios, to study both initial CCS projects and their coalescence into larger-scale CCS infrastructure;
5. demonstrate, through the development of the business cases listed above, the need for international cooperation on CCS;
6. summarise all findings in terms of actions to be taken by EU and national governments to facilitate and optimize the development of large-scale, European CCS infrastructure.

Project partners

Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek- TNO	Netherlands
Stichting Energieonderzoek Centrum Nederland	Netherlands
Etudes et Productions Schlumberger	France
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NV Nederlandse Gasunie	Netherlands
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Siemens AG	Germany
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Nacap Benelux BV	Netherlands
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Anthony Velder CO ₂ Shipping BV	Netherlands
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1 INTRODUCTION

1.1.1 Air protection

The aim of this report is to present a CO₂ capture installation, to be constructed in Bełchatów Power Plant. A new 858 MW generating unit is planned to be commissioned and synchronized with the national power grid in the second half of 2011.

Issues connected with CCS installation are still under investigation however many facts can be given at this point of the project maturity.

The Bełchatów CO₂ capture project is planned to be constructed as one of the EU demonstration projects.

Figure 1.1 shows electricity generation structure in Poland. Over 90% of the total production originates from hard and brown coal. This results in significant emissions of flue gasses. Annual amounts of CO₂ and other gasses are shown in Table 1-1.

The above fact makes Poland's participation in EU founded projects related to decrease of CO₂ emission very important.

Geological structure of Poland is very promising from the CO₂ storage perspective. Not far from the biggest lignite fired power plant in Bełchatów there are geological formations allowing for storage of significant amount of carbon dioxide.

Taking the above into consideration, the Bełchatów case study represents a full chain of CO₂ capture process- starting from emissions, through capture, transportation, finishing at the storage site- and may be valuable for CO₂ Europipe Project as the project facing all problems connected with the CCS process.

The distance for CO₂ pipelines within the Bełchatów project is relatively short, it does not exceed 100 km, however many problems are common with the large scale network.

Experience gained during the Bełchatów project execution can be used for large scale CO₂ transportation network.

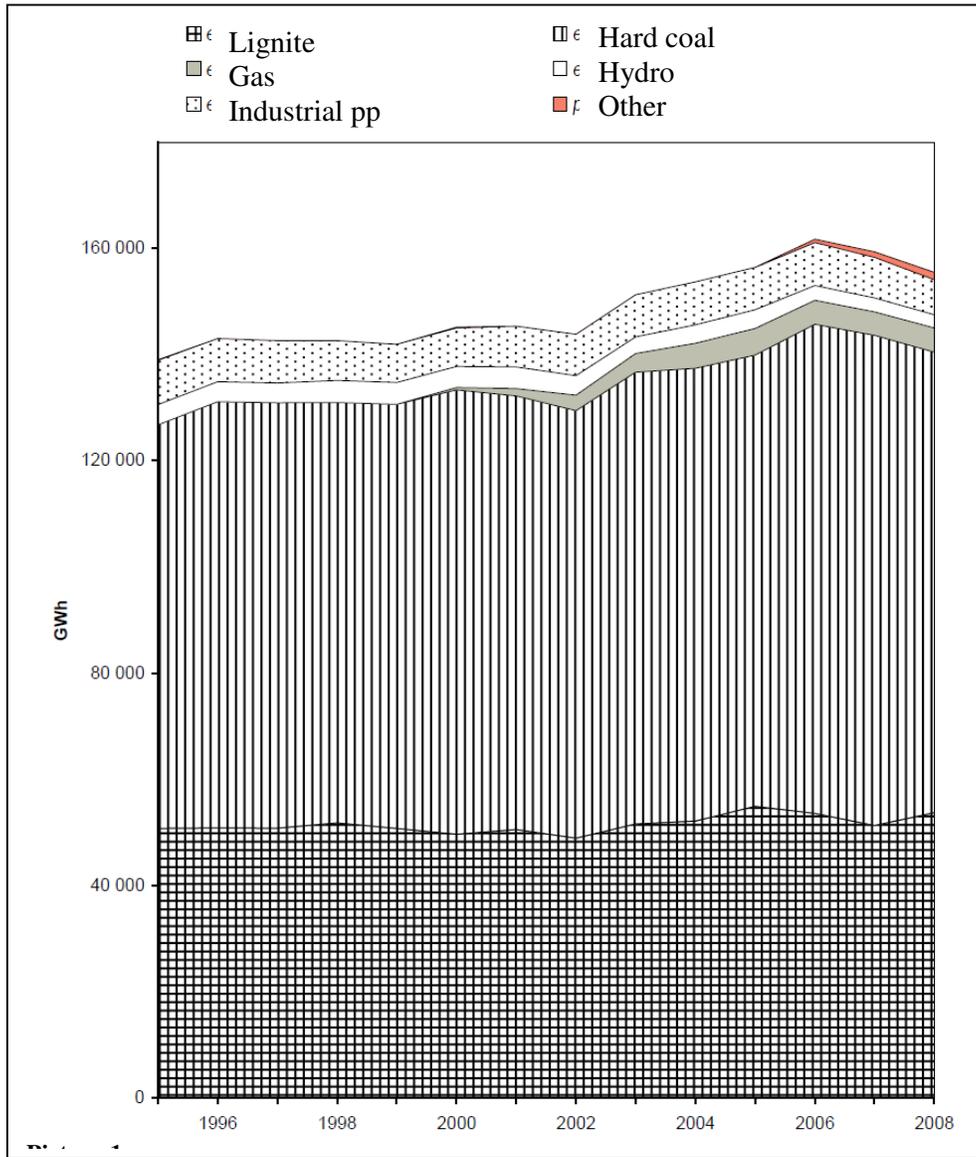


Figure 1.1 Electricity generation structure

Table 1-1 Emission of SO₂, NO_x, CO and CO₂ in Thermal PP and CHPs

		SO ₂	NO _x	CO	CO ₂
		tonnes			
TOTAL	2007	668 694	248 714	28 959	149 871 528
	2008	444 752	224 356	33 313	143 484 841
Power plants total	2007	530 914	197 113	22 844	118 635 063
	2008	344 438	177 444	28 073	115 395 235
including:					
Lignite	2007	287 566	74 377	10 083	54 784 928
	2008	199 898	71 304	10 721	56 949 340
Hard coal	2007	243 349	122 736	12 761	63 850 135
	2008	144 540	106 141	17 353	58 445 895
CHP total	2007	137 779	51 601	6 115	31 236 464
	2008	100 314	46 912	5 239	28 089 605

1.2 Electricity generation in Poland

Figure 1.2 shows number and location of thermal power plants in Poland. The total generation of hard coal and lignite fired power plants in Poland is shown in Table 1-2.



Figure 1.2 Fossil power plants in Poland.

Table 1-2 Annual values for PP and CHPs

	Unit	1995	2000	2005	2007	2008
Total installed capacity	MW	28 027	29 779	30 476	30 811	30 849
Including PP and CHP:						
Hard coal	MW	18 948	20 465	20 413	20 701	20 901
Lignite	MW	9 058	9 178	9 216	9 216	9 040
Gas	MW	21	136	847	872	883
Total power	MW	27 270	28 874	30 148	30 362	30 762
Including PP and CHP:						
Hard coal	MW	18 609	20 355	20 501	20 692	20 826
Lignite	MW	8 640	8 396	8 819	8 819	9 053
Electricity production	GWh	126 775	133 831	144 899	148 024	145 044
Including PP and CHP:						
Hard coal	GWh	76 029	83 671	84 983	92 336	86 718
Lignite	GWh	50 737	49 677	54 912	51 278	53 735

3 “CONSTRUCTION OF THE CO₂ CAPTURE, TRANSPORT AND UNDERGROUND STORAGE SYSTEM (CCS – CARBON CAPTURE AND STORAGE)”

The above project covers the following goals:

- attaining the “capture ready” status for a new 858 MW power unit by adapting the general construction plan for the 858 MW power unit and introduction of all the necessary modifications (retrofit) to the unit’s technological systems in order to adjust it to installation of the CO₂ capture system,
- construction of the 858 MW power unit’s flue gas CO₂ capture system,
- construction of the CO₂ compression station, transporting pipeline, underground storage facility, injection and monitoring plant.

3.1 Review of the available technologies

3.1.1 General remarks

In the stages of CCS CO₂ capture is the most costly (estimates run as high as 70%) and least technologically advanced element. However, one can observe a very quick progress in this realm and the large-scale demonstration systems will probably be commissioned within the next decade. The CO₂ capture process should enable separation of gaseous carbon dioxide from flue gas and its subsequent condensation. The level of carbon dioxide purity required for transport and storage has not been finally established yet. Condensation of the CO₂ captured is indispensable for the sake of transport (the best solution being cooled-down liquid or liquid in a supercritical state). Obviously, each type of fuel demands its own processing due to various contents. Solid fuels cannot be processed directly – they must be combusted or gassified beforehand. It should also be noted that CO₂ capture from the coal combustion processes naturally leads to an increased CO₂ emission reduction compared to application of the technology in gas combustion (since the carbon/hydrogen proportion is higher in coal than in gaseous gas).

The estimated CO₂ capture costs in various reports vary across a wide range due to various definitions being used. One must also remember that all the relevant data are based on practical experiences involving operation of small-scale systems or large scale systems operating under pressure. There are still no reliable data regarding CO₂ capture from industrial power generating installations.

3.1.2 CO₂ capture options

There are three main technological options of CO₂ capture from the power plant flue gas (Figure 1.1):

- capture after combustion,
- capture prior to combustion,

- oxy-fuel combustion or combustion including flue gas recirculation O₂/CO₂, and chemical technologies, such as flameless combustion with oxygen- known as chemical looping.

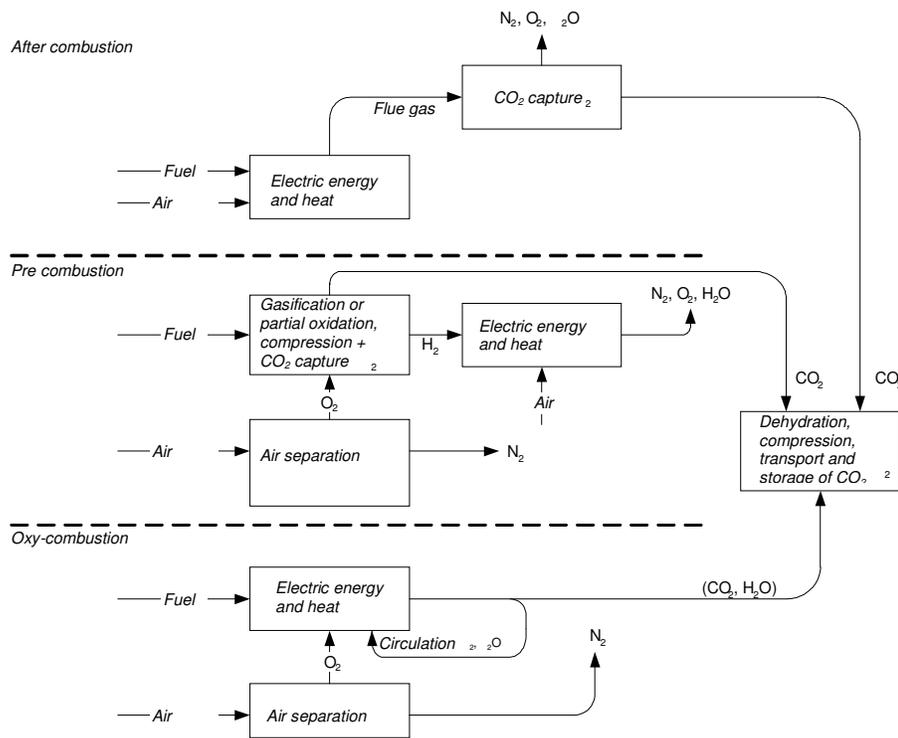


Figure 3.1 Technological options of CO₂ capture at power plants and combined heat and power plants

In the CO₂ capture process after combustion, CO₂ is removed from the flue gas leaving the boiler or the gas turbine. The most advanced commercial technology consists in CO₂ absorption in an aqueous amine solution. Next, CO₂ is subjected to desorption from the amine solution and dehydrated, and then compressed and transported to the storage area.

In the CO₂ capture process prior to combustion, the coal is gasified and the flammable gas obtained is subjected to reforming (water shift) as a result of which a gaseous fuel rich in hydrogen mixed with CO₂ is produced. CO₂ is removed and the remaining gas is combusted in the gas turbine. Thus CO₂ is removed at a higher concentration from the gas flux and at a higher pressure. A similar process can also be used for natural gas subject to reforming.

In the process of oxygen combustion with the flue gas recirculation O₂/CO₂, the fuel is combusted in a mixture of oxygen and CO₂ which is recirculated together with the flue gas for the sake of combustion temperature control. As a result of this process, the flue gas generated mainly contains CO₂ and steam which can be condensed, thus obtaining a gas flux of very high CO₂ concentration ready to be transported and stored.

When using natural gas in a mixed gas and steam system with a gas turbine, the flue gas produced contains CO₂ of low concentration. CO₂ emissions per MWh generated are low since natural gas contains little elemental carbon compared to the carbon present in a solid fuel and the electric energy generation efficiency is significantly higher in this case.

It is nowadays possible to apply most of these technologies using commercial equipment, however, certain modifications and adjustments are required. Nevertheless, in most cases, it is necessary to increase the scale of the equipment application considerably. The solutions planned in the nearest future will lead to a decrease in the electric energy generation efficiency of 8 to 13 percentage points for coal combustion and 9÷12% for gas combustion. Some 3-4% in coal combustion and 2-3% in gas combustion is related to the CO₂ compression process to attain the required pressure, whereas the remaining efficiency losses are due to the CO₂ capture process itself. The operating costs are ca. 10-50 EUR/MWh, however, authors of different publications provide very diverse values. All the aforementioned technological options require improvement of both output and efficiency. First of all, it is required that the electric energy generation efficiency is increased and the additional investment expenditures as well as the maintenance and repair costs are reduced. The CO₂ capture technology should best be taken into consideration as early as possible in the design stage, but it is also possible that an existing power plant is supplemented with the technology in an upgrading phase. The CO₂ capture option after combustion is mainly in upgrading activities. Upgrading can also invoke separation technologies applied prior to combustion for the combined gas and steam systems, and the oxygen combustion option featuring recirculation of flue gas O₂/CO₂ could be successfully applied in the existing coal-fired power plants.

Also the existing coal-fired power plants using an integrated gasification combined cycle (IGCC) could be equipped with installations for carbon dioxide separation prior to fuel combustion.

3.1.3 Carbon dioxide capture from flue gas

The purpose of the process is to separate CO₂ from other combustion products present in the flue gas. Separation technologies are based on various Physico-chemical processes, such as absorption (physical and chemical), adsorption, cryogenic and membrane separation. The choice of the separation technology depends on the flue gas properties, i.e. temperature, pressure, carbon dioxide concentration and flux volume, the last one being particularly large in power plants. Flue gas from a power plant is discharged to the atmosphere with a pressure close to the atmospheric one. The CO₂ concentration in the flue gas ranges from 5% by volume (for dry flue gas) in a combined gas and steam cycle based on natural gas to ca. 15% by volume (dry flue gas) for coal-fired power plants with pulverised-fuel boilers. Sorbents, usually used in commercial chemical installations, are compounds like cold methanol, polyethylene glycol, calcium oxide propylene carbonate, sodium hydroxide and potassium hydroxide. However, they are suitable for application at higher pressures than those typical for the flue gas directly discharged from a power plant (through the smokestack). For the sake of CO₂ adsorption from flue gas, one can use substances of considerable active surface, such as zeolites and activated carbon. The adsorbent is

reclaimed either by increasing temperature (by temperature swing adsorption) or by decreasing pressure (by pressure swing adsorption). However, the adsorption methods are not widely applied in large-scale installations as their output and selectivity towards CO₂ are not high, and large amounts of energy are required for the reclamation.

On the other hand, the cryogenic CO₂ separation technology requires large concentrations of carbon dioxide in the flue gas in order to maintain cost-effectiveness. Gas separation membranes, made of membrane materials of large pores compared to the dimensions of the gas particles to be separated (referred to as a thin film), separate gases selectively based on their interaction with the membrane and the difference in the particle pressures on both sides of the membrane. However, it is a fairly new technology and it has not been applied in wide-scale installations yet. Bearing the foregoing in mind, the chemical absorption process using a liquid reactive absorbent seems to be the most economically sound technology of CO₂ capture from the flue gas generated in power plants. Currently the only commercially available and active enough chemical absorbents for separation of CO₂ of low concentration from flue gas are aqueous solutions of alkanolamines. As a result of the activities performed in order to improve amine-based absorbents, new, modified absorbents based on sterically hindered amines have been introduced into the market showing higher resistance to impurities present in the gas and, most importantly, characterised by a smaller demand for heat required to reclaim the solution (CO₂ desorption).

In the most recent publications on carbon dioxide capture from flue gas, a new method (or rather a reviewed option) of CO₂ release by application of ammonia solution is often mentioned. In accordance with the said method, referred to as chilled ammonia, CO₂ is removed by way of absorption from flue gas cooled down to the temperature of 0-5°C, and then it is desorbed under an increased pressure. Among the advantages of such a solution, one can mention the reduction of the energy consumption for the absorbent reclaiming as well as decreased electric energy demand for the sake of compressing the CO₂ released as compared with the CO₂ absorption method using the MEA solution. However, it must be noted that this method is still being intensely tested (the tests are performed by ALSTOM) and due to the lack of practical/experimental data in the available publications on the subject one cannot verify its suitability/potential for application in the case analysed.

There is, however, sufficient information provided in the available publications on various amine absorbents, such as **monoethanolamine – MEA**, diethanolamine – DEA, diglycolamine – DGA, methyldiethanolamine – MDEA as well as combinations of those compounds. Each of the said amines is characterised by a certain specific range of operating parameters (Table 3-1) enabling them to be adjusted to the given industrial requirements. The amines used in the processes of acid gas absorption have at least one hydroxyl group and one amine group. It can be generally claimed that the hydroxyl group reduces the vapour pressure and increases water solubility, whereas the amine group is responsible for the solution alkalinity required in the acid gas absorption processes.

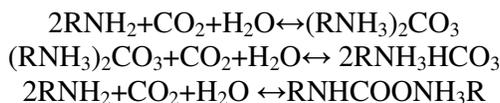
The most commonly used amines are MEA and MDEA (the latter being popular particularly due to the possibility of a selective absorption of H₂S in the presence of CO₂). The MEA solution shows the highest alkalinity among all the amines mentioned.

Eventually, it was decided that the CCS concept developed would be based on application of the MEA solution. It is characterised by high reactivity, stability, possibility of reclaiming and, most importantly, low price. Two most significant disadvantages of MEA are the high vapour pressure and the fact that MEA reacts irreversibly with COS (carbonyl sulphide). The first one can be eliminated by washing the desorption gas with water to avoid the loss of the amine vapours with the flux of treated gas. The second obstacle limits the MEA application to gases of low content of COS and CO₂.

Table 3-1 Typical operating parameters of the most commonly used industrial amine sorbents

	Amine sorbent type			
	MEA	DEA	DGA	MDEA
Solution concentration [%]	15-20 (30)	25-35	50-70	20-50
Acid gas load [mol/mol] (carbon steel)	0,3-0,35	0,3-0,35	0,3-0,35	no limitations
Selectivity towards H ₂ S	none	under specific conditions	none	under most conditions

The most fundamental reactions during the chemical absorption of CO₂ by primary MEA are as follows:



Consequently, the subsequent technical section of this document only applies to separation of CO₂ after combustion using amine solutions.

The processing system is composed of two main components, i.e. the absorber in which CO₂ is released from the flue gas and the regenerator in which CO₂ of high concentration is desorbed and the absorbing solution is reclaimed. Prior to CO₂ separation, the flue gas is usually cooled down to the temperature of ca. 50°C and then, from the flue gas, particles of dust are removed, since they can cause certain problems in operation, as well as other impurities (SO_x, NO_x, HCl, Hg) which then are subject to irreversible reactions with the amine being the reason for the losses of an expensive sorbent. The amine sorbent absorbs CO₂ (including trace amounts of SO_x and NO_x) forming a chemical compound of unstable bonds. The most essential disadvantage of an amine-based separation system is the large amount of heat required to reclaim the absorbent solution. Nearly 80% of the total energy consumed is spent on the reclamation process. A standard level of temperature during the reclamation is ca. 120°C. The thermal energy needed for this process is always taken from power plant's steam line, and hence the net efficiency is significantly reduced. For all CO₂ capture technologies, it is additionally required that electric energy be

consumed for compression of the CO₂ removed and its transportation to the storage facility.

The total amount of energy needed for reclamation is a sum of the reaction heat, the heat required to warm up the absorbent solution, the water evaporation heat and the absorbent evaporation heat. During the reclamation process, first the solution (containing CO₂) is warmed up to the stripper temperature by way of heat exchange. The value required for the heat recovery results from the thermal capacity of the absorbent, and the water present in the absorbent solution must additionally be evaporated in order to produce the steam for the desorption column. Consequently, the energy demand depends on the water content in the absorbent solution: the higher the water portion, the higher the energy demand is. Eventually, an appropriate quantity of energy must be supplied in order to break up the CO₂-absorbent complex formed during the absorption with the chemical reaction.

Table 3-2 *Enthalpy values for the most commonly used industrial solutions of amine sorbents*

Absorbent	M concentration / portion	CO ₂ portion	Solution enthalpy [kJ/mol CO ₂]
MEA	5 (30% wt)	0.4	72
DEA	3.5 (36%wt)	0.4	65
TEA	3.35 (50%wt)	0.5	62
MDEA	4.28 (50%wt)	0.5	53.2

The data provided in Table 3-2 imply that heat of the MEA reaction (solution enthalpy) is the highest among all the sorbents provided as a result of which a larger quantity of heat must be delivered to the MEA reclamation process compared with other processes. The additional heat demand of MEA for evaporation is also higher than that of the other sorbents as shown in Table 3-3.

Table 3-3 *Heat of evaporation of different amines*

Absorbent	Heat of evaporation [kJ/kg]
MEA	826
DEA	670
TEA	535
MDEA	550

Based on the above data, it can be concluded that MDEA is characterised by lower heat consumption than MEA.

Table 3-4 Reaction constants (primary) for various amines and CO₂

Amine type	K ₁ [mol/l.s]
MEA	7,600
DEA	1,500
DIPA	400
TEA	16.8
MDEA	9.2

Generally speaking, the higher the reaction rate, the better the mass transfer coefficient. The data provided in Table 3-4 imply that, while assuming identical diffusivity resistance, MEA is characterised by the highest reaction rate, whereas the reaction rate of MDEA is the lowest. And it is indeed for its high reactivity that MEA is currently recognised as the best potential absorbent for CO₂ capture from flue gas.

3.1.4 CO₂ capture systems

The largest operating installations for CO₂ release are currently characterised by a capacity of 1,000 tonnes of (removed) CO₂ per day. Carbon dioxide separation systems operating on a larger, industrial scale are in the planning stage. It is currently assumed that the largest diameters of absorbers may come to 12-15 m. The attainable CO₂ separation efficiencies may reach a level of up to 8,000 tonnes per day. Higher separation efficiencies can be obtained in several technological absorber lines featuring a single, shared regenerator. For the sake of comparison, a 500 MWe coal-fired unit generates ca. 8,900 tonnes of CO₂ per day and a 400 MWe gas-fired unit generates ca. 3,400 tonnes of CO₂ per day. These parameters obviously depend on several factors like the electric energy generation efficiency, chemical composition of the fuel as well as the CO₂ separation degree.

The amine-based absorption process can be designed in a manner ensuring that 85 up to 95% of CO₂ present in the flue gas is removed and that purity of the final product (CO₂) exceeds 99.9%. Both the CO₂ reclamation level and its final purity require optimisation. Also the choice of amines used in the absorption process is a matter of optimisation. The most important factors determining the choice of the absorbent include the CO₂ load (mol of CO₂/mol of amine), amine concentration in the solution, reaction enthalpy, evaporation enthalpy, conversion factor and reaction intensity, temperature level required for reclaiming as well as the corrosion aspects and costs. These parameters are obviously not optimal at the same time for the given absorbent and processing system. For instance, high absorption efficiency entails large reaction heat expenditure, etc. Therefore, the choice of an absorbent and optimisation of the whole process lead to compromises in terms of technical and economic premises. For instance, the MDEA amine enables saving energy as compared with other amines, like MEA, but the reaction itself is conducted at a lower rate and hence the absorption column would have to be much higher. In the process of carbon dioxide separation, aqueous solutions of amines are used in order to avoid excessive corrosion of the installation components. Water is yet another factor which involves certain requirements in terms of the system's efficiency and energy consumption. All these

technical factors must be taken into consideration along with the relevant directly connected economic factors. As a result of considerations like these, an increase of the amine concentration and application of corrosion inhibitors or complex amines are the most basic elements of all process licences. Japanese companies prepare special amines (sterically hindered amines, the most popular of which being KS-1 and KS-2). They are known to have the advantage that they can flow in the circuit at a slower pace due to the possibility of separating larger amounts of CO₂ in a single cycle, their reclamation temperature is lower and they require smaller heat of absorption. Furthermore, these amines are not corrosive for carbon steels at the temperature of 130°C in the presence of oxygen. The first commercial installation using the KS-1 amine has been in operation in Malaysia since 1999.

Chemical absorption can be complemented by using membranes which act as the contact media between the streams of gas and liquid. In such a configuration, the gas and the amine solution are not in immediate, and the flue gas components which cause the amine solution deterioration (e.g. oxygen) do not penetrate the amine solution to such an extent as without a membrane. Moreover, it minimizes solution evaporation into the treated flue gas. Also the pressure drop in the column is smaller than in a column with a typical packing, and hence the efficiency decrease can be limited. The configuration also enables using more compact devices owing to the increased gas-liquid contact. The membrane technology has been quite well developed and it is commonly used in gas separation installations in the petroleum and gas industry. At the same time, increasing the scale of the installations for the sake of their adaptation to the requirements of CO₂ separation in large power plants is commonly recognised as a very problematic matter.

Reclamation energy

The absorption processes, active at small partial gas pressures, are characterised by high reaction heat. Hence high energy consumption is required for reclamation. Therefore, the following aspects need process optimisation: minimisation of the reclamation energy through the appropriate choice of absorbents of lower reclamation energy demand, application of low-potential heat as the source of energy for reclamation. Absorbent solutions based on MEA require reclamation energy on the level of 3÷4 GJ/t CO₂.

The purpose of studies, being currently undertaken is to attain the reclamation energy of ca. 2 GJ/t. For the sake of absorbent reclamation (in the reboiler), steam at a pressure of 0.3÷0.5 MPa is used, and in a special device for the absorbent reclamation (reclaimer), steam of the pressure of ca. 0.4÷0.6 MPa is used. Usually the steam used for reclamation is delivered from the steam turbine bleeds, and therefore its flux responsible for the effective electric energy generation is decreased; the turbine power drop may become as high as 20%. The concentration of the MEA amine in a solution containing no corrosion inhibitors is limited to 15÷20% by weight exactly due to corrosion. A low concentration of the amine considerably increases the reboiler loading (and hence the reclamation energy). By using corrosion inhibitors, one can increase the amine concentration up to as much as 25-30% by weight, thus reducing the heat demand.

Flue gas temperature

Hot flue gas may cause degradation of the absorbent and reduce the absorber's efficiency. For the MEA amine-based absorbents, the flue gas temperature at the absorber inlet should not exceed 50°C.

Oxygen

Presence of oxygen in the flue gas may cause intensification of corrosion and degradation of the absorbent in the whole absorption system. Alkanoloamines such as MEA or DEA may be oxidised to carboxylic acids and thermally stable amine salts if no corrosion inhibitors are used. This problem can be solved by using an inhibitor which performs two functions: it is responsible for passivation of the metal surfaces and inhibits the amine degradation. An alternative solution to this problem may involve removing the whole oxygen from the flue gas through nearly stoichiometric combustion using a catalytic reactor.

SO_x

Sulphur oxides (SO_x) react irreversibly with the absorbents based on the MEA amine. Consequently, indecomposable and corrosive salts are formed. Therefore, one should consider whether, for any process based on the MEA amine absorbents, it might be cheaper to install a desulphurisation reactor or to come to terms with the absorbent losses on the SO_x concentrations exceeding 10 ppm by volume. This problem is particularly significant when using fuels of high sulphur content, such as coal, and less important for natural gas. An acceptable content of sulphuric oxides in the flue gas in combination with additional investment expenditures for the desulphurisation system are typical optimisation issues connected with the absorbent price.

Using SO₃ involves additional problems, since not only does it cause losing the absorbent by formation of thermally stable salts, but also by forming a corrosive aerosol of sulphuric acid in wet desulphurisation scrubbers. In such cases, one should use a special acidic cloud separator or a wet electrofilter and one should cool down the flue gas in order to intensify SO₃ capture in the desulphurisation system.

As a result of the reaction between MEA and other impurities of a more acidic nature than CO₂, the absorbent reacts, thereby forming salts which are not effectively decomposed under the absorbent reclamation conditions (conditions chosen in order to break up the amine-CO₂ bond) and stable amine salts, thus causing its deactivation. In such a case, one can opt for an absorbent reclamation system based on thermal reclaiming, i.e. distillation of a part of the absorbent flux, application of ion exchangers or electrodialysis (the last two methods being used to remove ionic impurities) as well as adsorption methods.

NO_x

Nitrogen oxides pose certain corrosion related problems and cause degradation of amines in certain absorption installations. In this respect, it is NO₂ (including N₂O₄, etc.) that is to be blamed since it forms nitric acid and eventually also thermally stable amine salts. The recommended level of NO₂ should be smaller than 20 ppm (by volume). Since modern power plants usually generate flue gas of lower nitrogen oxide concentrations, the content of NO₂ should not pose a serious problem.

Fly ash

Presence of fly ash in the absorption solution may cause formation of foam in the absorber and the regenerator (stripper), accumulation of hard residues on the device walls and in pipelines as well as clogging of the agents delivery tubes, erosion and corrosion. Moreover, certain amounts of the absorbent will be lost due to chemical degradation and physical bonding with liquid deposits from wastes.

Soot

If the separation in a heavy fuel oil-fired power plant is conducted using amines, a particular threat for the absorber is soot. Soot stabilises the amine cloud which is not captured in the water washing zone above the CO₂ absorption zone. In such a case, one must use a special cloud separator in order to prevent the MEA amine particles of micro size from escaping together with the CO₂-lean flue gas.

Wastes

The amine solution degradation in question causes formation of waste products that must be utilized, incineration being the optimal solution. The amount of waste generated is somewhat uncertain. However, it is estimated that the amount is several tonnes to several hundred tonnes per annum for a full-scale installation.

CURRENT STATE OF THE ART

The MEA amine based absorption processes were developed over 60 years ago for capture of acidic components from natural gas, for instance H₂S and CO₂. Later on, this process was adapted to flue gas treatment for CO₂ release and was intended to be applied to carbonification of saline, production of dry ice and saturation of beverages. This process was also used in order to enhance oil production using carbon dioxide. currently operating CO₂ separation installations are usually much smaller than might be required for power engineering applications. However, according to their constructors, building a CO₂ absorption installation for the flue gas generated in a power plant is technically feasible. Commercial CO₂ absorption installations with capacities corresponding to a coal-fired 400 MW_e power plant can be built by 2-3 potential contractors in the whole world.

Integration of the carbon dioxide separation system and the power plant

One of the definite advantages of carbon dioxide absorption using amines after the combustion process is the fact that the system can be integrated with the installations existing in the power plant without the necessity of introducing serious modifications of the power plant's main technological system. Consequently, the power plants operating at the moment can be extended by adding the CO₂ separation systems. The main modifications are introduced within the steam circuit where most of the steam from a low-pressure turbine is taken up to deliver energy to the absorbent reclamation in the reboiler. Therefore, the electric energy generation capacity may drop by as much as 20%. As a result of the dramatic reduction of the steam mass flow through the low-pressure turbine, some modifications of the turbine itself may also prove necessary.

Further research and development works in need

The purpose of the description below is to present the framework of required R&D works identified with regard to the amine-based CO₂ absorption processes.

Absorbents:

Reduction of the steam consumption and temperature required to conduct the reclamation

- obtaining more energy-effective amines (lower energy required for reclaiming, lower temperature of reclamation, higher concentration of amines in solutions),
- optimisation of amine mixtures,
- Reduction of the electric energy consumption for the system needs
- preparation of amines of higher CO₂ absorption capabilities to obtain higher concentrations and reduced dimensions of devices and pumps.

optimisation of amine mixtures,

- Reduction of the amine absorbent loss
 - one should seek amines of lower partial pressure of vapours,
- Amine degradation reduction
 - preparation of new amines less susceptible to high temperatures and impurities such as SO_x, NO_x and O₂,
 - preparation of new inhibitors, process modifications and membranes,
- Preparation of different types of absorbents

CO₂ capture from flue gas:

- Integration of the CO₂ capture system and the power plant
 - technological integration of desorption and operation of the steam turbine in relation to steam feed from the low-pressure turbine section,
 - utilisation of the intercooling heat of CO₂ compressors to warm up the feed-water,
 - identifying other possibilities of process integration for the heat from flue gas cooling, amine solution cooling and other streams of waste heat that can be utilised for other purposes (e.g. district heating, feed-water heating, etc.),
- Reduction of the power demand for the flue gas fan (for the carbon dioxide separation system)
 - improved packing (in the absorber) – reduction of the pressure drop in the absorption column).

Process optimisation for a system operating on a large industrial scale:

- Process modifications, e.g. division of the absorbent flux into two streams of various amine concentrations,
- Improvement of simulation tools used in optimisation for better forecasting of the system operation,
- Examining the possibility of reducing costs as a result of more extensive application of large installations,
- Demonstrating long-term operational availability and reliability of the power plant operating on a full scale.

The fact that many research projects in the field of CCS problems have been undertaken all around the world shows the actual interest in the matter and the intensity of present R&D. (source: Carbon Capture And Storage: a WEC “Interim Balance”)

PGE GIEK S.A. – TECHNICAL AND TECHNOLOGICAL CHARACTERISTICS

PGE GiEK S.A. is the largest power generating company in Poland. The facility comprises 12 lignite-fired power units of the capacity of 370 MW each which results in the total installed capacity of 4,440 MW with three units generating thermal power operating in a combined cycle. The annual electric energy output comes to 27.8 TWh whereas the annual thermal power output exceeds 2,100,000 GJ (0,6 TWh).

The engineering design of the Bełchatów Power Plant (Elektrownia Bełchatów S.A.) was prepared in the 1970s entailing the most advanced technological solutions applied in power engineering at the time. Coal is supplied to the power plant with belt conveyors straight from the nearby strip mine. The engines and other elements operating at the power plant were manufactured by different Polish companies. In order to ensure more efficient utilisation of the heat generated during the electric energy production, under combined heat and power generation heat is fed into the district heating system of the town of Bełchatów and nearby industrial facilities.

3.2 Description of the power unit to be coupled with the demonstration CCS system

In order for the Bełchatów Power Plant to retain its leading position in the domestic power generation market, the company is required to comply with the provisions of the “Strategy for Development of the Generating Power at PGE GiEK S.A.” which assumes that a new 858 MW power unit is to be erected starting from 2006 whereas power units no. 3-12 are to be subjected to comprehensive upgrading.

The basic assumptions of the upgrading include extending the operating times of units no. 1 and 2 (until 2016) and units no. 3-12 (until 2030-2035). There is to be improvement of the operating parameters, reducing any negative environmental impact, adapting the Bełchatów Power Plant to the environmental protection requirements as per EU Directive 2001/80/EC and increasing the Power Plant’s available capacity up to 4,500 MW.

In 2001, the company obtained an official approval of the Polish Ministry of Treasury for development of the construction design for a new 833 MW power unit (which is now known to have the capacity of 858 MW). Under the tendering procedure commenced in 2002, the bid submitted by the ALSTOM consortium was chosen. In 2005, the construction design was approved and the construction permit was granted. Actual construction started in October 2006. During the construction of the power unit, state-of-the-art technologies and latest know-how as regards large-scale power units are to be used. The first synchronisation with the national power system (KSE) is planned to take place in 2011.

The basic engineering design for the boiler unit proposed will be delivered by the ALSTOM Power Boiler company. The detailed engineering design for the pressure

part and steel structures including material supplies will be developed by ALSTOM Power Boiler and RAFAKO S.A.. Both companies are very experienced in performing similar projects they participated in as consortium partners.

The most important piece of equipment to be installed at the boiler room will be a supercritical steam forced-through-flow tower boiler featuring a pulverised fuel fired furnace. The boiler will be equipped with 8 fan-type beater pulverising mills, two air and flue gas fans, burners, bunkers, a rotating and a steam air preheater as well as all the necessary electrical installations, local measuring systems and auxiliary systems. The boiler will also feature a longitudinal afterburning grate, a slag trap and a system of soot blowers. The boiler pressure part will be characterised by a design durability of 200 thousand hours of operation as per the EN and DIN standards which corresponds to 25 years of operation. The unit will feature a heat recovery system enabling recovery of heat from flue gas prior to the inlet into absorbers of the flue gas desulphurisation system and delivery of the heat to the condensate preheating system at the engine room. After ash removal in electrofilters, cooling in the heat recovery system and desulphurisation in the flue gas desulphurisation system, the flue gas from the boiler will be discharged into the atmosphere through a cooling tower.

POWER UNIT CHARACTERISTICS INCLUDING THE BASIC OPERATING PARAMETERS

The new 858 MW power unit, like the existing power plant, will be fired with lignite delivered from a nearby strip mine using the existing belt conveyors connecting the Bełchatów Power Plant and the mine.

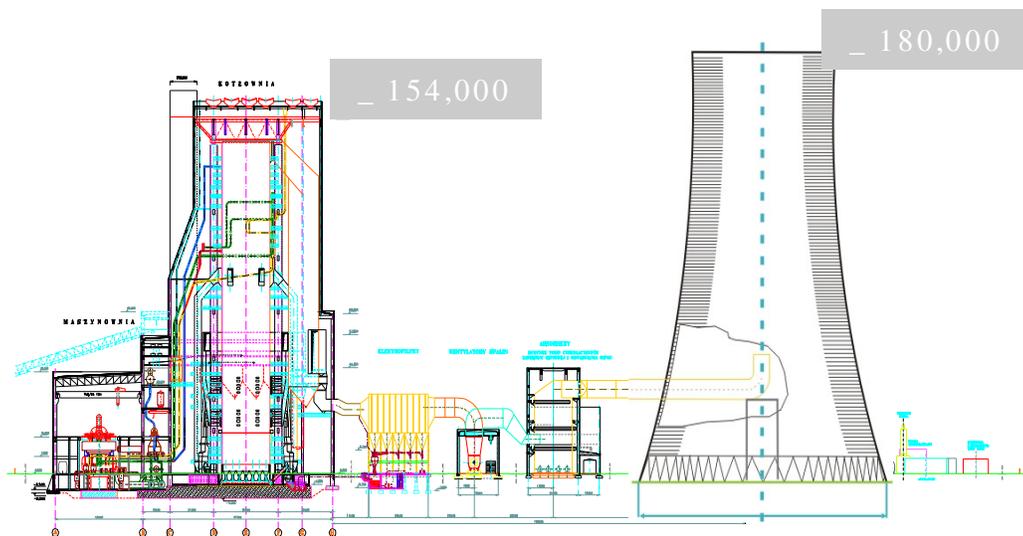


Figure 3.2 Summary diagram of the 858 MW power unit

The new 858 MW power unit will feature all the necessary systems as well as basic and auxiliary installations as provided under the scope of delivery section in Part 4 of the Technical Specifications. The unit will include the following installations:

- A complete one-pass forced-through-flow pulverised coal fired boiler including coal feeding systems and coal pulverisers, slag discharge installations, air supply and flue gas discharge systems, flue gas heat recovery system, steam and water systems, etc.,
- A turbine set comprising a steam turbine and a generator including auxiliary installations and handling systems, feed-water pumps, etc.,
- A flue gas desulphurisation (FGD) system featuring an unloading and storage system for limestone dust, a sorbent suspension preparation system as well as a gypsum dehydration system including gypsum storage and a system of gypsum loading on trucks,
- A cooling tower also used to discharge treated flue gas into the atmosphere and a complete cooling water system,
- A water preparation system featuring a raw water intake, a process water preparation system and a sewage neutralisation system,
- Electrofilters,
- A coal handling system featuring bridges and auxiliary systems starting from the link with the existing coal handling system of PGE GiEK S.A.,
- A hydraulic ash and slag transport system,
- A power take off system including two simultaneous unit transformers,
- An electric system and the automatic control and measurement installation,
- Power unit’s auxiliary installations and systems such as the ignition oil system, handling systems, water supply and sewage disposal systems, heating systems, compressed air system and systems supplying other media,
- Buildings and built structures including the central building holding the boiler room, engine room and electrical equipment room, workshops, office buildings, trestle bridges and auxiliary structures as well as transport road and rail system.

The 858 MW power unit will be designed to work under the basic operation system with the assumed power generation time of 7,500 hours per annum and the overall operation time per annum of ca. 8,100 hours. The annual unit’s electric energy output is 6.3 TWh. It will be a power generating unit of high availability, high degree of automation and the design efficiency of 42%.

Table 3-5 Characteristics of the 858 MW power unit at PGE GiEK S.A.

Parameter	Units	Design coal	Upper threshold coal		Lower threshold coal		Notes
Lower heating value	kJ/kg	7,750	8,700		6,500		
Moisture content	Wt- %	51.4	47	51.52 for	56	48.19 for	temporary 46 to 58 %

Parameter	Units	Design coal	Upper threshold coal		Lower threshold coal		Notes
				minimum ash content		maximum ash content	
Ash	Wt- %	11.4	13.46 for minimum moisture content	8.7	10.05 for maximum moisture content	18.4	temporary maximum 22 %
Sulphur content (total)	Wt- %	1.26	0.6		1.85		
Sulphur in pyrites (Fe ₂ S)	Wt- %	0.52	0.08		0.76		
Chlorides in coal (Cl)	Wt- %	0.008	0.005		0.010		
Fluorides in coal (F)	Wt- %	0.009	0.007		0.011		
Brittle xyloid coals	Wt- %	5.0	1.5-14.5				
Fibrous xyloid coals	Wt- %	1.5	0.5-10.0				
(Na ₂ O)	Wt- %	0.059	0.027 ÷ 0.137				
(K ₂ O)	Wt- %	0.027	0.01 ÷ 0.047				
Alkali content:							
(Na ₂ O)	Wt- %	0.059	0.027 ÷ 0.137				
(K ₂ O)	Wt- %	0.027	0.01 ÷ 0.047				
(CaCO ₃)	Wt- %	5.5	1.0 ÷ 12.7				
Volatile particle content:	Wt- %	54.0	49-58				
Hardgrove grindability index	° H	58.6	48-80				
Natural slip angle		31 ÷ 35°	31 ÷ 35°				
Bulk density	kg/m ³	750-800	750-800				
Granularity	mm	0-300	0-300				
Coal granularity in bunkers	mm	0-80	0-80				

Table 3-6 Composition of flue gas from the 858 MW power unit past the electrofilter at PGE GiEK S.A.

FLUE GAS CHARACTERISTICS PAST THE ELECTROFILTER			
Parameter	Nominal conditions, WTT-NC	Maximum flue gas quantity	Unit
CO ₂	12.16	11.57	% by vol.
SO ₂	0.20	0.39	% by vol.
H ₂ O	24.76	28.11	% by vol.
O ₂	2.50	2.37	% by vol.
N ₂	60.34	57.55	% by vol.

Table 3-7 Flue gas characteristics past the desulphurisation system

Stream		Treated flue gas from one absorber
Load		Design coal – 100% of boiler load
Gas composition on 6% of O ₂ in normal (dry) conditions		
SO ₂ content	mg/m ³	≤200
SO ₃ content	mg/m ³	21,1
SO _x content	mg/m ³	≤217
HCl content	mg/m ³	≤3,5
HF content	mg/m ³	≤3,5
Ash content	mg/m ³	≤30
Drop content	mg/m ³	≤50

The flue gas desulphurisation system of the new 858 MW power unit will apply a new wet limestone based method in two absorbers treating 50% of the flue gas stream each. In its absorption section, the flue gas desulphurisation system will be composed of two passes being extensions of the boiler passes. The flue gas will be delivered through two flue gas fans to the absorbers featuring suspended matter circulating pumps and oxidising air fans, and then it will be transported to the cooling tower. In the absorber, first the SO₂ will be absorbed (in the flux of the sorption suspended matter delivered through the absorber’s circulating pumps), and next calcium sulphite (CaSO₃) will be oxidised in the absorber’s bottom section using the air delivered by the blowing fans. The suspended matter containing hydrated calcium sulphite (gypsum) will be delivered by the discharge pumps to the hydrocyclone system where it will be pre-condensed and sent to the final gypsum dehydration system at the vacuum filters for gypsum production. After the desulphurisation process, the wet flue gas will be discharged through the cooling tower.

3.3 Processing and technological assumptions for the demonstration system of CO₂ capture, transport and storage

Analysis, evaluation and choice of the CO₂ capture technological process for the 858 MW power unit at PGE GiEK S.A.

The information provided in the previous sections of this study as well as the analysis of numerical data and their evaluation, as regards the current stage of progress, enable a decision on the MEA amine method of carbon dioxide capture from the flue gas flux at the 858 MW power unit of the Bełchatów Power Plant. For the sake of CO₂ capture from the flue gas, a 30% solution of a primary amine, namely monoethanolamine or MEA, will be used as the absorbent.

Amine washing enables capture of CO₂ from the flue gas flux of pressure close to the atmospheric one. As previously stated in the preceding sections of the study, the amine method is widely applied for capture of acid gases from process flue gas fluxes (primarily in the chemical industry). In most publications on CCS, it is mentioned as the main method available for CO₂ capture from the flue gas generated in industrial power engineering installations to be applied within the next years.

The high steam demand of CCS systems (CO₂ desorption) requires determination of the bleed stream flux to be delivered from the turbine to the CO₂ capture system without impeding correct turbine operation.

In accordance with the relevant guidelines for a CCS system based on the MEA technology, for the desorption processes, steam of the pressure of 0.3-0.5 MPa is used, and the fluxes of available steam are humidified and decompressed to attain the parameters of 0.36 MPa of pressure and the temperature of 140°C.

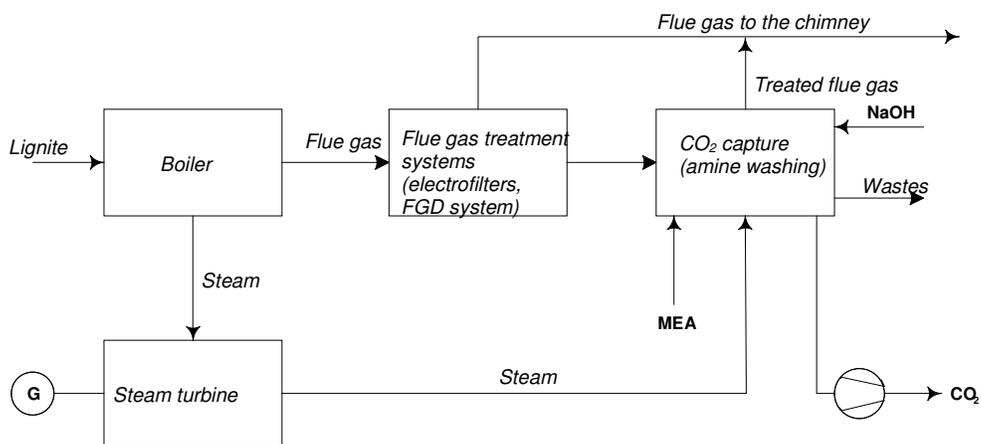


Figure 3.3 Summary block diagram of CO₂ capture from the 858 MW power unit at MW PGE GiEK S.A.

The technology to be applied in the CO₂ capture systems at the 858 MW power unit will be based on wet amine washers, and it will consist in CO₂ absorption from the

flue gas using a solution of primary amine (MEA) as the absorbent followed by reclamation of pure CO₂ for further transport and the final storage. ALSTOM, being the Applicant's partner, has already been implementing similar technologies in pilot. As shown in the above block diagram, the CCS system should operate on a partial flue gas flux from the 858 MW power unit (Figure 3.3) The volume of the flue gas flux delivered to the demonstration system has been chosen so as to ensure that the amount of available steam (value defined by the Contracting Authority) corresponds to the CCS system's heat demand required for the process of removing carbon dioxide from flue gas.

An hourly efficiency of such a CCS pass will come to nearly 120 tonnes of pure carbon dioxide. The composition of the flue gas assumed in the model calculations of the CO₂ absorption process corresponds to the one past the desulphurisation system. According to the data obtained, the SO₂ concentration is ca. 200 mg/m³ which corresponds to the concentration of ca. 70 ppm whereas the recommended maximum concentration should equal ca. 10 ppm which corresponds to a content of 28 mg/m³. An increased content of SO₂ exerts negative influence on the CO₂ absorption system by reducing the MEA concentration as well as through losses/deactivation of the amine due to the reaction with SO₂. In the system under scrutiny, increased losses of amines were taken into consideration due to the reactions with SO₂ and the need for MEA replenishment, and consequently an increase of the CCS system's operating costs. In order to compensate for the negative impact of the increased SO_x content, one can use a supplementary solution of an ion exchanger or an electrolysers to work on a part of the reclaimed absorbent solution flux, i.e. past the station of filters **F** (Figure 3.4) the purpose of which is also to remove the products of the absorbent degradation by way of adsorption on solid adsorbent, e.g. activated carbon. Experimenting with the demonstration system on a flux of flue gas might well suggest further technological solutions and the best equipment efficiency parameters that may be attained.

The assumed quantity of flue gas from the adsorber past the desulphurisation system (i.e. 700 t/h) whose pressure (ca. 0.1 MPa) and circulation is forced using blowing fans, is preliminarily cooled down in a scrubber to reach a temperature of ca. 40°C. Cooled flue gas is delivered to absorber **A** (Figure 3.4) where up to 90% of carbon dioxide is washed away. The CO₂ is absorbed to reach a 30% aqueous solution of monoethanolamine (MEA), and due to the high concentration of MEA, the solution requires addition of antioxidants, such as quinine compounds and anti-foaming agents. The flue gas treated in the absorber, after passing the drop capture system, is delivered to the cooling tower being the flue gas emitter. The MEA solution saturated with carbon dioxide is pumped through the main heat exchanger (**WG** Figure 3.4) where the heating agent is the reclaimed MEA solution from the desorber. The saturated MEA solution at the temperature of ca. 100°C feeds the top of the reclamation column – desorber **D** (Figure 3.4). The carbon dioxide desorption process is performed in the steam flux generated in the desorption (reclamation) column evaporators (**WD** Figure 3.4). At the top of column **D** (Figure 3.4), a mixture of steam and carbon dioxide is intercepted, next it is cooled down in the heat exchanger in order to condense the steam and then separated in the separator **S** (Figure 3.4). The

carbon dioxide separated in the aforementioned manner is delivered to the dehydration and compression unit, and then to the storage facility.

Temperatures inside desorber **D** (Figure 3.4) are maintained on a level of ca. 120°C at the column bottom and up to 96°C at the top. The reclamation column (**WD** Figure 3.4) evaporators are supplied with steam at 0.36 MPa, whereas the reclaiming evaporator (**R** Figure 3.4), where the MEA degradation products and ballast salts are removed, is supplied with steam under higher pressure due to the necessity of obtaining a temperature of ca. 140°C.

The reclaimed MEA solution, after passing heat exchanger **WG** (Figure 3.4), is delivered to the top of the absorption column. The separated CO₂ stream is then delivered to the compression and dehydration system on a level enabling safe transport by pipeline. The CO₂ stream is dehydrated in the temperature swing adsorption (TSA) drying system using the SG-B127 Grace-Davison narrow porosity silica gel. For a short period of time, the cyclic TSA process is used, when the individual operations of drying, reclamation and cooling take 60 minutes each. Dried carbon dioxide is then cooled down and the final pressure enabling transport and injection to the storage facility of 12 MPa is obtained by multistage compression.

In order to utilise the available media to the fullest extent, the CCS system is configured in a manner enabling the process water released during CO₂ capture in the drying and compression installation to be reused to replenish the amine solution. After the relevant arrangements with the Contracting Authority, a modification was introduced into the cooling system for the desorbed MEA solution by installing an intermediate heat exchanger where the cooling agent is steam condensate. During this process, the condensate recovering the heat from the amine solution is warmed up to temperatures from 30°C up to 60°C.

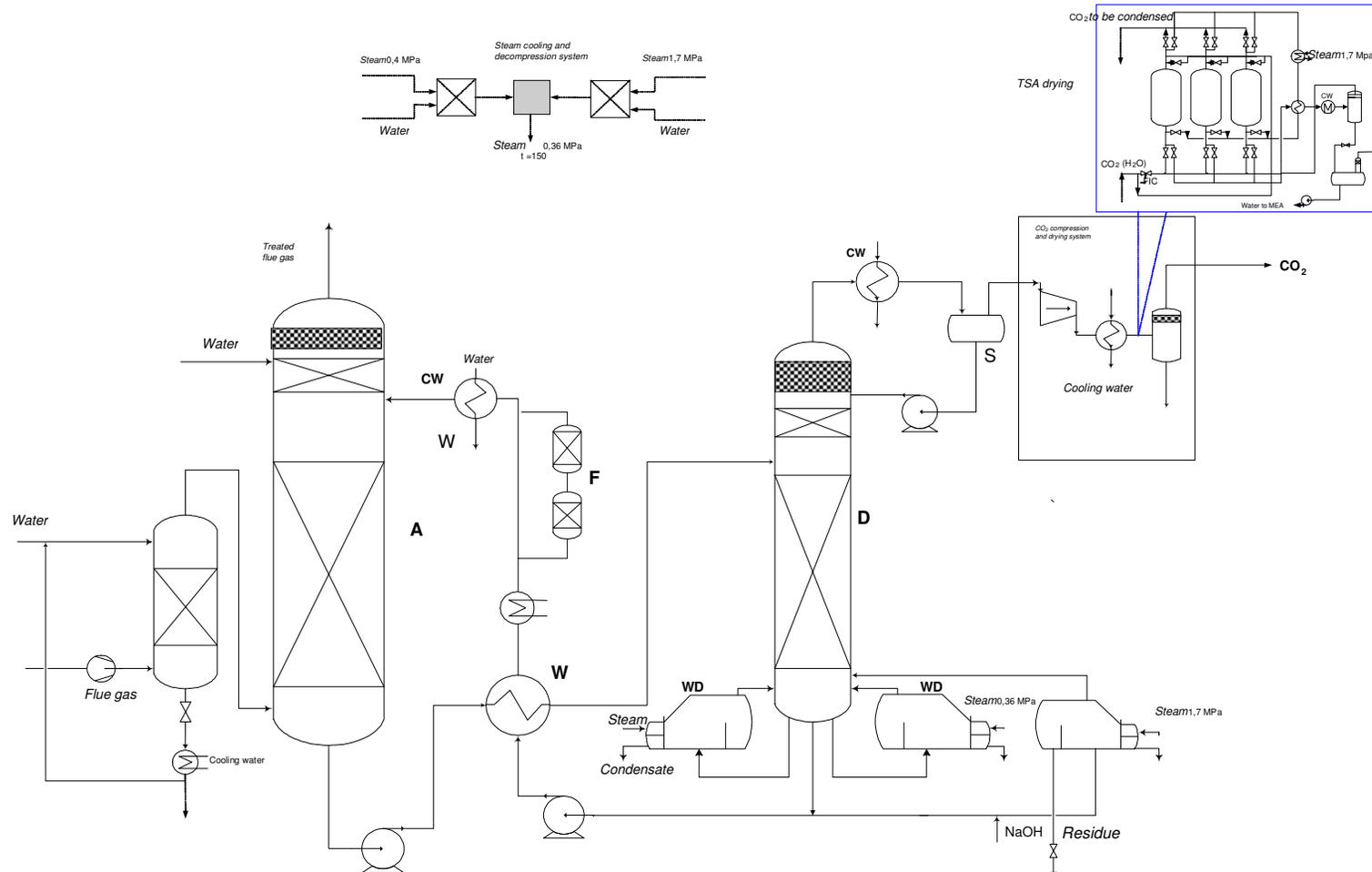


Figure 3.4 Diagram of the system for carbon dioxide capture from flue gas by amine washing.

CO₂ absorption and desorption process modelling

Balance calculations were conducted using the ChemCAD v.5.6.1 process simulator for the steady state of the technological process.

The following assumptions were adopted:

- Flue gas flux to the CCS system – 700 t/h,
- Absorbent – 30% aqueous solution of MEA,
- Design efficiency of the absorption process – 90%,
- Pressure of the steam for desorption – 0.36 MPa,
- Carbon dioxide transported in a liquid state at 12 MPa.

The calculations were conducted for flue gas composition as below (Table 3-8).

Table 3-8 Flue gas parameters past the desulphurisation system – data provided for a single absorber

Flux		Treated flue gas from one absorber
Load		Design coal – 100% of boiler load
Flow rate under normal (dry) conditions	m ³ /h	1,209,592
Flow rate under normal (wet) conditions	m ³ /h	1,698,508
Actual flow rate	m ³ /s	604.95
Actual flow rate	m ³ /h	2,177,810
H ₂ O steam flux	kg/h	392,990.2
H ₂ O steam flux in drops	kg/h	60.4
Total mass flow rate	kg/h	2,056,211
Flue gas mass flow rate to CCS	kg/h	700,000
CO ₂ content	% by vol. _dry flue gas	16.29
O ₂ content	% by vol. _wet flue gas	3.38
H ₂ O content	% by vol. _dry flue gas	28.78
H ₂ O content	% by weight _dry flue gas	23.63
Temperature	°C	67
Density under normal conditions	kg/Nm ³ - wet flue gas	1.211

3.4 Analysis, evaluation and selection of a system to transport CO₂ to the place of storage and issues related to risk and safety management

The use of **road transport** for liquid CO₂ (standardised tankers with a capacity of 20 tonnes) was tested as part of the completed RECOPOL project. Taking into account the current prices, the approximate cost of transport of 100 tonnes of CO₂ over a distance of 100 km is more or less 5000 zlotys (1200 Euro). Bearing in mind those costs, as well as the limited capacity of the tankers, it needs to be emphasised that the system is certainly not fit for the intended purpose, given the assumed potential amounts of CO₂ to be stored. It is ruled out due to the economic criterion, but most of all due to logistic problems (too many transporting units, i.e. lorries) and to problems related to the limited tonnage of the roads.

Another potential solution that could be used to deliver CO₂ to the storage site is **rail transport**. Depending on the location and on the technical constraints (setting out the route, traffic routes, sidings, transshipment and unloading stations, etc.), the solution makes it possible to deliver larger amounts of CO₂ (compared to road transport), but it is impossible to perform an initial (indicative) calculation for the investment at present. The above solution could be used at the pilot/exploratory phase or at the semi-industrial phase.

Considering the literature, if large amounts of the CO₂ stream are delivered to the storage site, **only transport by pipeline** may be taken into account both from the technical and from the economical point of view.

The technical parameters selected for transmission (pipeline diameters, transmission pressure, thermal insulation) depend mainly on the amount of gas transmitted. An important requirement related to CO₂ transport by pipeline is protection against corrosion. And, of course, systems should not leak.

Safety of CO₂ transmission through pipelines

The safe functioning of carbon dioxide transport through a pipeline to the storage sites will depend on the resistance of the system, should any sudden interferences occur resulting from unexpected shutdowns of system elements caused by failures, natural/technological disasters or terrorist attacks.

Types and potential sources of failures

The Ordinance of the Minister of Environment, Natural Resources and Forestry dated 14 July 1998 on the determination of the types of investments particularly harmful for the environment and for health (Journal of Laws Dz. U. No. 93 of 1998, item 589) classifies pipelines for gas transmission (depending on their diameter and length) as investments potentially causing particular harm to the environment and to human health. The sources of failure have their origin both inside and outside the system. Reasons for failures inside the system are objective (technical) in nature, and the most important ones are component faults, corrosion and unstable placement in the ground. External reasons are failures in linked systems and actions of third parties, including accidental damage to gas pipelines during the performance of road works and drainage works, devastation and sabotage as a form of terrorist activity. Regardless of the nature of the cause, failures that may occur in the gas system include

depressurisation or rupture of the pipelines, as well as shutdown or explosion of the pump (compression) stations.

Transmission system safety management

Experience of the gas industry proves that damage to carbon dioxide transmission pipelines occurs most often due to external circumstances and agents and due to corrosion and defects in structural elements. In order to increase the safety of carbon dioxide transmission using pipelines, **technical means** should be used to protect the transmission pipelines against the impact of external agents (concrete slabs and protective meshes laid out above the pipeline, encasing pipes, marking plates and tapes, increased wall thickness). **Formal actions** undertaken to ensure safety include preparation of a **safety report** and of an **internal operational and emergency plan**. The method and scope of preparation of the safety report are laid down in the ORDINANCE OF THE COUNCIL OF MINISTERS of 9 November 2004 on the determination of the types of activities that might have a significant impact on the environment and on the detailed restrictions related to the eligibility of undertakings for preparation of an environmental impact report – Art. 51, paragraph 8⁽¹⁾ of the Act of 27 April 2001 – Environmental Protection Law (Dz. U. No. 62, item 627, as amended⁽²⁾)

The safety report includes: a description of the user of the facility and of the safety management principles adopted, an assessment of the risk of extraordinary hazards occurring, including identification of sources and areas of hazards and assessment of the impact of the hazards on humans and on the environment, and a description of the procedural and organisational solutions aimed at ensuring safety. The gas transmission pipeline operator shall develop a **Safety Management System** on the basis of the safety report and of the technical and organisational means that are available. One of the elements of the Safety Management System is the **Failure Prevention Plan** prepared on the basis of the hazard assessment identification and of the results of acceptable risk level analyses; the plan contains procedures applied in order to limit risk and to minimise the consequences of emergencies.

The Safety Management System also includes a **Programme of Actions for Pipeline Integrity Maintenance**. The said programme is supported by operating procedures, a programme of preventing damage caused by third parties, training, repair and maintenance plans, procedures for gas hazardous works, as well as plans and procedures related to materials management. Implementation of the programme is accompanied by constant identification and assessment of hazards and supervision over compliance with procedures.

The **technical and organisational means** significant for the safe use of the carbon dioxide transmission network are used both at design stage and during construction and operation. Basic conditions include: application of and compliance with the European regulations and standards, using all technical and organisational means in order to prevent failures, design and construction of the facilities by reputable entities (applying quality systems), scrupulous checking of project implementation, efficient checking of the transmission system by the operator in conformity with the operating procedures, as well as having emergency plans in place and being able to apply them. The table below contains examples of the most significant specific methods and tools used at subsequent stages of life of the pipeline in order to ensure process safety and reduce the hazards for the environment and for the population.

In order to ensure a suitably high level of safety of the carbon dioxide transmission system, preventive actions will also be necessary reducing the risk of hazards occurring. In preventive actions it is important to recognise which local factors are important for safety, protection against third party activities using the technical means available and physical protection.

Hazard caused by terrorist activity is comparable to random failure hazard caused by third party activity or by operator errors. Preventive action and counteracting on the part of the operator is identical in both cases.

Table 3-9 List of preventive means used to ensure the required technical safety for the transmission system

Design stage	Construction stage	Operation stage
Suitable material selection, Strength calculations, Reliability analysis, safety report, Active and passive corrosion protection design Simulation of operating conditions using the finite-element method (FEM), Determination of controlled zones, Communication system design, Distance minimisation	Certification checking, design supervision, Saddle-bag weights, etc. Encasing pipes, Double communication system (fibre optic cables and radio line), Protection against corrosion, Drainage, soil replacement, fascine mattresses, Land surveys, Soil compaction inspection, Non-destructive testing of joints, Stress test, Acceptance inspections according to guidelines	Cathodic protection efficiency check, Check using smart heads, SCADA, Fencing protection system, CCTV system, Access control, Periodic training, Works according to procedures, Integrity audit reports

Risk management

The transmission system operator ensures long-term safety of carbon dioxide transmission and reliability of its functioning. The register of failures and disturbances together with the annual assessment of technical condition constitutes the basis for the analyses of system failure risk performed by the operator.

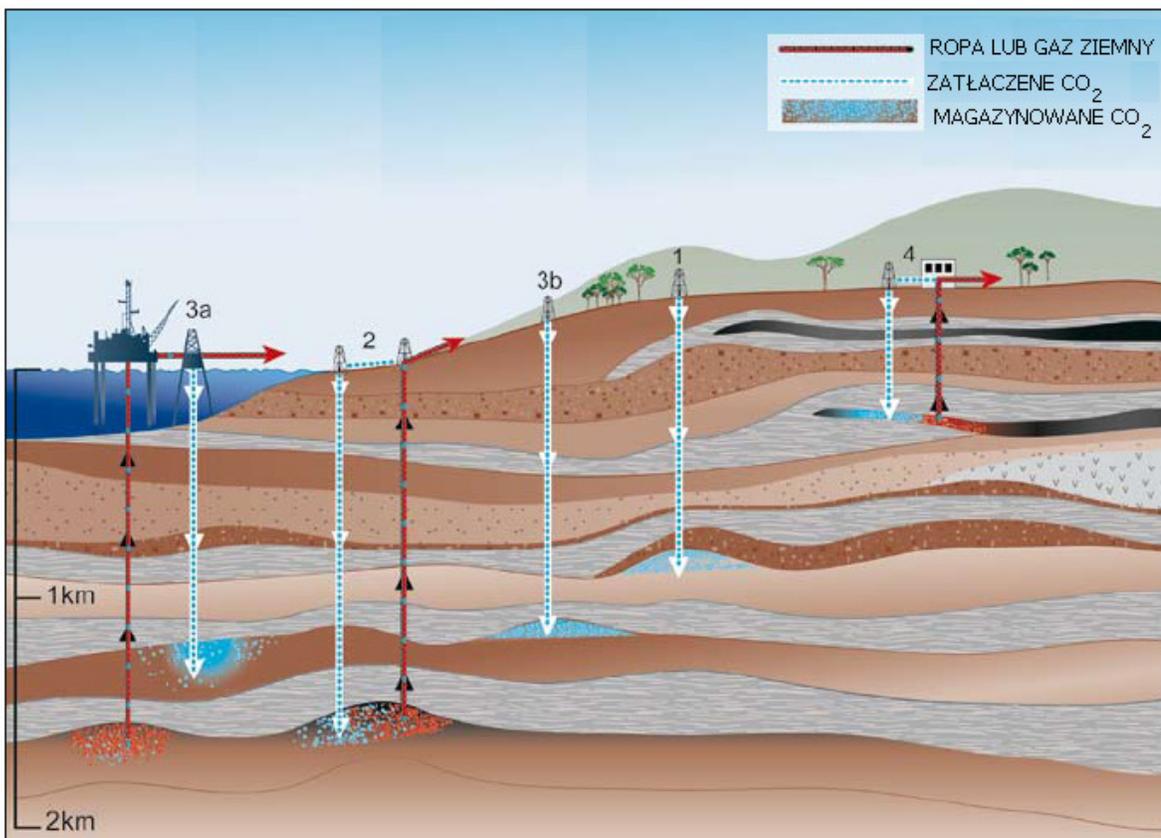
The following should be considered as the basic stages of the risk management process:

- risk identification,
- risk management process planning,
- classification, measurement,
- planning of methods of reacting and counteracting,
- risk phenomenon supervision and control,
- management throughout the project implementation (life) cycle.

All the aspects discussed above and related to the management of safety and risk in the transmission of CO₂ using pipelines to the places of injection refer to the stages of design, construction and intended operation.

3.5 Analysis, assessment and selection of the process of technological storage of CO₂

Figure 3.5 shows, in pictorial form, the various possible options of storing CO₂, i.e. using gas and oil reservoirs, using CO₂ in the Enhanced Oil Recovery (EOR) process, storage in deep saline formations – offshore and onshore, as well as using CO₂ to intensify the extraction of methane from unminable coal seams.



ROPA LUB GAZ ZIEMNY – OIL OR NATURAL GAS
 ZATŁACZENIE CO₂ – CO₂ INJECTION
 MAGAZYNOWANIE CO₂ – CO₂ STORAGE

Figure 3.5 Review of the possible CO₂ storage options: 1 – gas and oil reservoirs used; 2 use of CO₂ in the EOR process; 3 – deep saline formations: a – offshore, b – onshore; 4 – use of CO₂ to enhance methane extraction from unminable coal seams

Precise recognition of the conditions prevailing in the CO₂ reservoir selected and knowledge about the physicochemical phenomena which will occur during the injection of CO₂ into the geological structure and confirm the expected absorbing capacity of the deposit are very important due to the high costs of construction of the

surface facilities used to transmit carbon dioxide in pipelines. Taking into account the experience of the Central Mining Institute acquired during the RECOPOL project, and additional data from other storage sites in the world, it may be assumed that considering the specific nature of the geological formations suggested in this case injection and storage will be technically feasible. Bearing in mind the substantially better parameters in terms of absorption capacity and permeability of the aquifers compared to the hard coal formations ultimately used to inject CO₂ into during the RECOPOL project, which eventually proved successful (achieving constant injection), in our opinion the project at the Bełchatów Power Plant will be technologically feasible.

Taking into account the know-how acquired and the detailed geomechanical and physicochemical parameters of the deposit obtained during well testing, we are able to select suitable parameters for the system together with what is referred to as the “SCADA” (Supervisory Control and Data Acquisition) system.

A typical system for CO₂ injection includes (but is not limited to) the following elements:

- feeding pump,
- CO₂ pre-heating system (depending on the actual needs),
- pipe connection system to the well head, and
- sensor and measuring instrument set for the system in connection with the inspection and control system.

Specific system parameters are selected depending on the physical state of the medium delivered, as regards injection rate, temperature and pressure.

The main element of the system with regard to CO₂ storage will be the injection wells, the test wells and the reservoir. The number of injection wells required to obtain the required injection rates will be determined in a future stage. It will depend on the hydrogeological parameters of the aquifers, on the area selected, on the number of saline aquifers with a single intake and on their depth.

This least advanced variant assumes drilling of the following:

- One injection well of a depth of 1,500-2,200 m (depending on the area and number of aquifers it constitutes an intake for), with a target diameter of approx. 7”;
- One inspection and testing well with a depth as above, i.e. 1,500 to 2,200 m, with a diameter of approx. 4”.

This number of wells should not be considered final, due to uncertainty around amounts of CO₂ to be injected in the future and to the absorption capacities of geological formations.

Currently existing systems make it possible to store over 1 Mt of CO₂ annually, e.g. in the Sleipner deposit in Norway. The estimated capacity per well, with reference to the saline aquifers, may reach up to 5 Mt per year. This, however, will depend on the absorption capacity of the relevant aquifer, which will only be determined by specific testing.

It is therefore initially assumed that one injection well and one inspection and testing well will need to be bored. Further wells will need to be bored depending on how the injection proceeds and on the phenomena observed. The number of such wells should also be determined in the course of earlier model tests.

Transport by pipeline

The transport pipeline to the storage site is an essential element. The exact parameters of this pipeline will be defined at subsequent stage of the project after the amount of the CO₂ delivered per time unit is determined. As already mentioned, preliminary work related to the determining the geological conditions of the formation may involve transport by road of small amounts of CO₂ for experimental purposes.

Storage

The main elements of the system with regard to CO₂ storage will be the injection wells, the test wells and the reservoir. The number of injection wells necessary to obtain the required injection intensity will be determined at the further stage of the work. It will depend on the hydrogeological parameters of the aquifers, on the area selected, on the number of saline aquifers with a single intake and on their depth.

If the variant with at least three geological wells is applied, with the wells subsequently used for testing and observation purposes, (during the injection test), the following goals will be attained:

- much better recognition of the geological conditions, especially with regard to the regularity of deposition, thickness and continuity of reservoir layers and isolating layers;
- possibility of precise investigation of the CO₂ permeability and absorption capacity of the geological structure and of the surrounding isolating rock;

investigation of the speed and range of CO₂ penetration in the porous medium of the geological structure, with a suitable distribution of the testing and observation wells;

investigation of the storage stability or decrease of CO₂ content over time, which would point to an existing puncture or to a slow leaking of the gas injected.

Drilling geological wells in the interval where isolating and collector layers occur should be performed using core barrels. The cores obtained will make it possible to perform laboratory and model investigations with regard to volume, absorption capacity and permeability.

Recognition of the potential locations of CO₂ storage places

The following requirements on aquifers are deemed suitable for underground storage of CO₂:

- aquifers with a thickness of more than 80-100 m,
- good layer permeability,
- good and very good reservoir parameters of the water-bearing series,
- with a several hundred metre layer of isolating formations in the roof,
- located at a large distance from the supply zones,
- located far from tectonic discontinuities.

At the same time, it is recommended that the following conditions should be created at surface: the area of the reservoir should not be densely populated, without large industrial facilities, water basins and legally protected areas, it should be far from potable and geothermal water intakes as well as from underground and surface waste storage facilities.

Four areas were marked out in the PGE GiEK S.A. area with potentially good conditions for CO₂ storage. Due to future injection requirements it may be necessary to inject CO₂ in several areas at the same time.

Indication of places suitable for underground storage of CO₂ is a specialist (hydro) geological task performed with a view to the needs of the specific industrial facility. Numerous aspects need to be considered in the selection of the future storage place, such as the following:

- the amount of CO₂ planned for injection now and in the future,
- reservoir parameters of deep geological structures that must absorb and carry the CO₂ injected,
- the reservoir should have a gas capacity allowing at least 10-20 years of injection or more,
- the behaviour of the gas after injection into the reservoir,
- reservoir tightness,
- pattern and nature of faults,
- distance to supply zones and outcrops of the reservoir series,
- the physicochemical reactions that will occur where CO₂, rock and water come into contact.

Appropriate selection of the formation suitable for CCS is a responsible geological task, also in financial terms. Tasks of that type have been performed in the last 10 years by some leading research centres in Europe and co-financed by the EU and with state and private funding. In Poland relevant activities are still in progress.

Suitable storage areas were indicated by the Department of Geology and Geophysics of the Central Mining institute specifically for injection of CO₂ from PGE GiEK S.A. All free available geological material was used for that purpose, while more specific material may be available with consent of the competent minister.

In the future it will be necessary to carry out a specific investigation/design stage. The most favourable location will be indicated at that stage for the underground injection, and specific answers will be given concerning the following:

- possibilities of using the level/reservoir;
- storage safety,
- number of production wells,
- location of wells,
- potential physicochemical reactions etc.

According to the project performance schedule, enough time is provided to complete the investigation stage of the work.

Geological structure of strata suitable for CO₂ capture and storage

The formations suitable for the underground reservoir are those deposited in the area of the Łódź-Mogilno Basin. The basin is a large, regional geological structure passing central Poland from NW to SE. It has an average width of 50 km, a length exceeding 300 km and a surface area of 19,600 km².

To the NE the basin borders on the Kujawy Bank, and to the SW on the Pre-Sudeten block. The borders are tectonic in nature. The basin structure creates significant potential for underground storage, but it also shows some limitations resulting from the occurrence of border fault zones and, locally, large depths.

The Mogilno-Łódź Basin is filled with the following formations with increasing depth: *Lower Cretaceous, Upper, Middle and Lower Jurassic, Upper Triassic* and older deposits.

Lower Cretaceous formations are represented by sandstone, carbonate, mudstone and claystone deposits. Their thickness in the area of the planned reservoirs ranges from

30 to 100 metres, the thickness of water-bearing formations is 30 to 80 metres, and the roof of the formations can be found at depths of 100 to approx. 2000 metres below ground level. The possibilities of development concern aquifers in sandstones and in sandy/carbonate formations (*Hauterivian* and *Barremian*). These formations have parameters that are favourable for underground storage, but they are already used by local potable and geothermal water intakes.

Upper Jurassic formations are developed in the sandy and carbonate facies. They contain aquifers (mainly in the *Oxfordian* stage) isolated by clayey deposits. The total thickness of Upper Jurassic formations in the area of the potential reservoirs ranges from 150 to 600 metres, the roof can be found at depths from 0 to more than 2,000 metres below surface, and the thickness of the water-bearing formations ranges from 120 to 600 metres. The parameters of the water-bearing formations are not very favourable for underground storage of media and only locally can better parameters be documented for them.

Middle Jurassic formations are represented by clastic and carbonate deposits forming aquifers (mainly in the *Bajocian* and *Bathonian* stages) with hydrogeological parameters that are not very good. The roof of the formations is deposited in the areas of the potential reservoirs at a depth of 200 to more than 2,000 metres, and the thickness of aquifers reaches 40-200 metres.

Lower Jurassic formations are represented by a complex of sandstones and by alternating sandstones and mudstones. The aquifers dating back to the *Sinemurian* and *Pliensbachian* stages have a thickness of 50 to 200 m. In the area considered, the roof of that complex is located at a depth of 500 to 2,500 metres. Deposits containing water have favourable hydrogeological parameters.

Upper Triassic formations are represented by sandstones, conglomerates and mudstones. Formations containing water occur mainly in the *Rhaetian* stage, but they mostly do not present excellent parameters in terms of water content. The roof of the series is deposited quite deep in the area considered, i.e. at a depth of 900-2,600 metres below ground level.

Suggested places for underground CO₂ storage

Preliminary suggestions for underground storage were presented as part of the work. They are supposed to give the Investor an idea about the areas where CO₂ injection is possible and which obstacles could occur on the route of the transmission pipeline leading from the Power Plant to the underground storage facility.

Human and environmental safety aspects were taken into account upon selection of the places for the CO₂ reservoirs. All the reservoirs suggested are located outside cities and large components of the environment (such as rivers, water reservoirs, main railway lines and roads, etc.), and the populated centres located in their area are defined as “villages” on the map. The suggested injection places are shown in Figure 3.6 and Figure 3.7.

Location 1 – area of Sieradz, the distance from the Bełchatów Power Plant is up to 60 km as a crow flies. There are three Jurassic members here where CO₂ may be injected, showing good reservoir parameters, deposited at a depth of more than 2,000-2,500 metres below surface, and partly a Lower Cretaceous member with good

hydrogeological parameters, deposited at a depth starting at 1,800 metres below surface.

Fresh waters occur in the Lower Cretaceous formations and such waters are used – through municipal intakes and geothermal water intakes. The Jurassic formations, on the other hand, contain highly mineralised waters, qualifying for balneological development.

Location 2 – area of Łódź, 40 km from the Power Plant.

There are three Jurassic members in this area that can be used for CO₂ storage facilities, with a sandy and carbonate development, whose roof is deposited at a depth of 800-2,300 metres below surface, locally showing good hydrogeological parameters and a water mineral content 5 to 110 g/l. There are large water reservoirs in these formations, and an optimum place for CO₂ injection may be selected in their area.

In order to transport CO₂, a pipeline would have to cross the local road between Wrocław and Warsaw, which could generate slightly higher costs of CO₂ transport.

Location 3 – area of Wieluń, 40 km from the Power Plant. Lower Jurassic formations containing water can be used to store CO₂, with roofs at a depth of 500 to 600 metres below surface.

The formations show very good reservoir properties, high aquifer thickness of at least 150 m and a favourable level of mineralisation ranging from 5 to 15 g/l, making them unsuitable for human or industrial use.

Further investigations (of reservoir tightness in particular) are necessary to determine whether these formations are actually suitable for storage.

Location 4 – to the south-west of Sieradz, at a distance of 70 km from the Power Plant. Jurassic formations are suitable for CO₂ injection 1,600-2,400 metres below surface. The thickness of the strata for injection is 100-500 metres, and water mineralisation is 15-90 g/l.

It will be possible to specify the most favourable location for future CO₂ injection in a definitive manner after performing a detailed geological analysis, which represents a **routine** procedure in such works both in Poland and in other European countries. Future studies will require an analysis of the conditions of storage and of CO₂ behaviour after injection into underground strata; in this respect the phenomena of *precipitation* and *recrystallisation* may occur, they should therefore be defined in advance and suitably counteracted. It will also be essential to determine the direction of CO₂ flow in the aquifer, the tightness of the future reservoir and the number and lay-out structure of the injection wells needed to avoid the phenomenon of well interference.

The schedule of such works related to transport to the CO₂ storage place includes the following stages:

Exploratory activities

STORAGE

I. Initial stage

Performance of geological, hydrogeological and geophysical works leading to the final indication of the area/rocks/aquifers recommended for CCS.

Performance time: at least 6 months

II. Specific stage

Performance of specific research with regard to the technology and efficiency of underground CO₂ storage and design.

Performance time: 12 months per reservoir.

System construction stage

STORAGE

- | | |
|------------------------------------|----------|
| 1. Drilling of 1 well | 3 months |
| 2. Rock mass fracturing | 2 months |
| 3. Field tests and related studies | 6 months |
| 4. Laboratory tests | 6 months |
| 5. Sealing old wells | 6 months |

If the organisation is efficient and a substantial amount of equipment is used, the activities related to underground storage can be completed in 6 to 8 months.



<i>utwory dolnej kredy</i>	– Lower Cretaceous formations
<i>utwory dolnej jury</i>	– Lower Jurassic formations
<i>utwory dolnego triasu</i>	– Lower Triassic formations
<i>proponowane miejsca do zatlaczania</i>	– places suggested for injection

Figure 3.6 Map of selected regional reservoirs and suggestions concerning the injection of CO₂ from PGE GiEK S.A.



▼ wstępnie proponowane rejony do składowania

Figure 3.7 Location of the places initially suggested for CO₂ storage

Municipal water intakes

All the pre-selected places of CO₂ injection are located outside the boundaries of Primary Groundwater Resources and the areas supplying them. The closest significant municipal intakes occur:

- in the area of Łódź: intakes drawing underground waters from Lower Cretaceous formations. They are located in the area of the Primary Groundwater Resource No. 4010, Łódź Basin. It is a porous reservoir where fresh waters occur, water intake reaching 800 metres.
- in the area of Sieradz: intake drawing waters from Upper Cretaceous formations. It is located in the area of the Primary Groundwater Resource No. 312, Sieradz. It is a small reservoir of fractured-porous nature, from which water is produced by a well with an average depth of up to 150 metres.
- in the area of Kalisz and Wieruszów, intake of water from Quaternary formations. They are located in the area of the Primary Groundwater Resource

- No. 311, Prosna River. It is a porous reservoir from which water is produced by a well with a depth of up to 30 metres,
- to the south of the investigated area, in the neighbourhood of Pajęczno and Działoszyn, intake of water from Upper Jurassic formations. They are located in the area of the Primary Groundwater Resource No. 326, Częstochowa (E), of fractured-karst nature. Well intakes with an average depth of up to 160 metres are used to produce water from the reservoir.

NATURA 2000 areas

All the initially suggested places of CO₂ injection are located outside Natura 2000 areas.

Geothermal water intakes

The closest intakes are located at a distance of 20 and 110 km from the suggested storage places. They produce water from the Cretaceous stratum.

Estimated CCS potential

The estimated CCS potential calculated for Lower Jurassic formations within the reach of locations 1, 2, 3 and 4 ranges from 38 to 72 million tonnes of CO₂, representing a total of 160 million tonnes. This means that 1.7 million tonnes of CO₂ might be injected into each of those places every year, over a period of 13 to 42 years. At present it seems that the optimum solution from the point of view of safety would be to inject CO₂ into one or two reservoirs at the same time, with a single transmission pipeline.

There are large reserve storage capacities in the area of the Bełchatów Power Plant, but the final approval of the remaining reservoirs for CCS will be possible only after their tightness has been analysed.

3.6 Basic balance indicators of the CO₂ capture, transport and storage system for PGE GiEK S.A.

Calculations gave the values for the CCS system balance fluxes listed in Table 3-10.

Table 3-10 Properties of the most significant CCS system fluxes

No.	Agent	temp [°C]	pressure [MPa]	flow [kg/h]	flow [kg/s]
<i>Consumption</i>					
1	Flue gases for CO ₂ capture	66.8	0.1	700,000	194.44
2	process water	30	0.4	73,140	20.32
3	water vapour	>140	0.4	90,000	25.00
4	water vapour	250	1.7	106,830	29.68
5	steam condensate	30	1.7	12,700	3.53
6	cooling water – supply	25	0.3	9,126,500	2,535.14
7	cooling water – supply	18	0.3	1,224,500	340.14
8	boiler water	30	0.3	1,805,000	501.39
				13,138,670	3,649.63
<i>Production</i>					
1	Flue gases to the chimney	63	0.102	527,703	146.58
2	liquid CO ₂	27	12.0	119,598	33.22
3	produced water *)	30	0.1	117,600	32.67
4	water vapour condensate	139	0.36	190,000	52.78
5	water vapour condensate	200	1.6	19,530	5.43
6	cooling water – return	40		9,126,500	2,535.14
7	cooling water – return	30		1,224,500	340.14
8	boiler water	63		1,805,000	501.39
9	sludge	30		8,230	2.29
				13,138,661	3,649.63
	*) to be used after treatment				

Consumption of electrical energy for the CCS process was determined: the highest consumption was found to be caused by the compression of CO₂ to a pressure ensuring safe transport by pipeline to the storage place. It is worth so mention that Bełchatów approach includes CO₂ compression into the capturing process, whereas many sources include compression into the transportation phase.

Table 3-11 Own consumption of electric energy for the CCS system

	Energy consumption	efficiency [%]	MW
1	Flue gas blower	75	5.325
2	CO ₂ compressor	80	12.382
3	Pumps	75	1.725
	<i>Total</i>		19.432

Table 3-12 Annual consumption of chemicals in the CCS system

		Mg/year
1	MEA top-up	1,480.50
2	NaOH	128.31
3	Activated carbon	74.03

PGE GiEK S.A. has worked on the preparatory task to develop a demonstration scale CCS installation integrated with the newly-built 858 MW unit since 2007. At present, as a result of the Consolidation Programme of the PGE Group, the CCS project is run by PGE Górnictwo i Energetyka Konwencjonalna SA (PGE GiEK SA) and will include the following key components as the full value chain in the CCS technology validation process:

- A Carbon Capture Plant (CCP) of equivalent power of >250MW and a CO₂ capture efficiency of >80% utilizing the Advanced Amine Process (AAP) and its integration with the 858 MW unit. It means, that the CCP will capture approximately 1,8 million tonnes of CO₂ per annum. The new 858MW unit will be modified for the needs of the CCP construction to obtain the status „Capture Ready”
- CO₂ Transportation: this component will consist of a pipeline and the associated infrastructure to transport the compressed CO₂ from the Carbon Capture Plant (CCP) to the storage site
- CO₂ Storage: this will include the injection of pressurized CO₂ into the ground (deep saline aquifers) for permanent storage.

Within the solutions concerning the technology in the „post-combustion” option, the AAP technology has been selected as a the most mature technology available for CO₂ capture dedicated to the CCP at Bełchatów Power Plant. The amine solvent by The Dow Chemical Company is particularly suitable for this application versus alternatives due to its higher capture rate, tolerance to impurities of the flue gas stream, lower degradation rates and corrosion properties. The AAP process also has a smaller footprint allowing a relatively easy CCP integration with the existing Base Plant – the 858 MW unit. The Dow Chemical Company has developed an advanced solution concerning formulation and performance of the solvent in the Advance Amine Process, whereas Alstom processes improvements and implementation of the AAP technology in the pilot and, subsequently, the demonstration phase aiming at future commercial use after 2020. Alstom has been progressing an extensive test work

in the USA at the bench-scale and pilot-scale at a new testing facility in Charleston using flue gases produced by fossil fuel power generation. This aims at gathering robust technological data for the design and engineering of the CCP at Bełchatów Power Plant.

The CCP will compress the CO₂ prior to transportation by pipeline at supercritical fluid conditions. In terms of the CO₂ transport potential transportation routes have been identified. These potential routes of the CO₂ pipeline have been included in the Łódzkie Voivodeship Area Development Plans. Concerning the storage component – three potential storage sites have been identified based on the various studies and analyses. The detailed appraisal of these storage sites is ongoing. The research work is carried out by two contractors: the Polish Geological Institute and Schlumberger (Carbon Services Division) and the work comprises a high-level characterization of the three potential geological structures and definite selection of one structure in the first half of 2011.

The execution schedule for the entire CCS Project:

CCP – Building Permit: Jan 2010,

Construction Completion: Jun 2014,

Ready for start-up: Dec 2014,

TRANSPORTATION PIPELINE –

Building Permit: Aug 2013,

Construction completion: Dec 2014,

CO₂ STORAGE –

Storage site selection: first half of 2011,

Permit application and storage site construction start-up: Dec 2012,

Injection decision issued: Dec 2014

CCS INSTALLATION –

the optimization process completion and CCS final commissioning: Dec 2015

The PGE GiEK SA's CCS Project was selected, along with five other European CCS projects, to receive €180 million subsidy that would come from the EU funds in the framework of the European Energy Programme for Recovery (EEPR) in the field of energy aiming at stimulating the development of economic activities during the economic crisis. In addition to the €180 million grant being the subject of the EEPR application, PGE GiEK SA is seeking additional funding from sources such as Structural Fund allocated to Poland, Green Investment Scheme (this mechanism enables allocation of the funds coming from purchase and transfer of the Assigned Amount Units (AAUs) for targets and projects to combat climate change), resources within the “NER 300” (New Entrant Reserve) – a mechanism to be implemented within EU Emissions Trading System – and potentially preferential loans from the European Investment Bank (EIB) and Bank Ochrony Środowiska S.A. (Polish bank of the environment).

Awarding of the EEPR grant is essential for the implementation of the project and specifically for the initial phase of the project in 2009/2010. This is because the investment is not viable commercially and is not expected to become viable until the cost of EU Emission Trading System, e.g. ETS certificates, reaches parity with the costs of implementing and operating the CCS facilities. To conclude, without this grant it will not be possible to reach the levels of financing required.

The strategic impact of public understanding and acceptance of the CCS concept will be substantial in enabling its widespread commercialisation. As an additional longer-term economic benefit, it is expected that the project will lead to the creation of new green jobs in Poland and across Europe in manufacturing, construction, operation and maintenance of CO₂ capture, transport and storage installations. Funding of mature demonstration projects like the one run by PGE GiEK SA all over Europe together with appropriate political decisions will enable the EU to firmly establish Europe's global leadership in the development of this innovative technology and support the efforts to tackle global warming. The PGE GiEK SA's CCS Project will show that CCS exploits the potential of existing and available energy sources while guaranteeing substantial CO₂ emission reductions. A successful operation of the Carbon Capture Plant at Bełchatów Power Plant will allow the technology to be demonstrated at a large scale on the new, modern 858 MW power generation unit. The latter is a necessary step for eventual commercialization and wider use of the technology.

3.7 Economic analysis

3.7.1 Basic assumptions

	Unit power		
(gross according to FS)	858.3		
Own needs of the power unit according to EPC	49.7		
net power without CCS	808.6		
Net efficiency without CCS	41.8%		
Net efficiency with CCS	39.7%		
Net power without CCS	808.6	MWe	
Net power with CCS	768.7	MWe	
Electric energy loss	39.9	MWe	to steam for CCP purposes
CCS system efficiency	1,805	thousands of tonnes of CO ₂ /y	
Annual operating time	7,710	h/a	
Unit steam consumption	2.2	GJ/t	
Steam consumption	3,971,000	GJ/year	
Market price of energy from coal	300	PLN/MWh	
Unit CO ₂ emission per 1 MWh (net) without CCS	937	kg/MWh	
Percentage of paid CO ₂ emission in the relevant operating year	100%		
Component of CO ₂ costs without CCS in the price of energy	73	PLN/MWh	20
Value of energy without CO ₂ costs	227	PLN/MWh	
Production at 41.8% efficiency	6,234,537	MWh	
Production at 39.7% efficiency	5,926,991	MWh	
Electric energy production losses	307,547	MWh	
Value of losses in electric energy production	69,776,707	PLN	
Quantity of steam extracted from the turbine	3,971,000	GJ	
Cost of steam extraction for CCS per GJ with regard to losses in electric energy production	17.57	PLN/GJ	
<i>Average thermal power in steam for CCS</i>	<i>143</i>	<i>MWt</i>	

3.7.2 Insurance cost

No	Component	Sum insured	Rate	Insurance cost for the entire investment period	If warranty clauses are included
1.	capture	1,404,500,000.00	0.7%	9,831,500.00	1.5
2.	transport	424,300,000.00	0.2%	848,600.00	
3.	storage	474,300,000.00	0.4%	1,897,200.00	
TOTAL				12,577,300.00	
				Insurance rate	
No.	Component	Insurance type	Sum insured (in PLN)	Rate	Annual insurance cost for CCS system (in PLN)
1.	capture	fire and natural disaster insurance (OG)	1,404,500,000.00	0.045%	632,025.00
		machinery breakdown insurance (MB)	280,900,000.00	0.09%	252,810.00
TOTAL (annual cost – capture component)					884,835.00
2.	transport	fire and natural disaster insurance (OG)	424,300,000.00	0.045%	190,935.00
		machinery breakdown insurance (MB)	84,860,000.00	0.09%	76,374.00
TOTAL (annual cost – transport component)					267,309.00
3.	storage	fire and natural disaster insurance (OG)	474,300,000.00	0.045%	213,435.00
		machinery breakdown insurance (MB)	94,860,000.00	0.09%	85,374.00
TOTAL (annual cost – storage component)					298,809.00
TOTAL (annual cost)					1,450,953.00

3.7.3 Investment cost and cofinancing

EUR exchange rate for system construction	4.00	PLN/EUR	
USD exchange rate for system construction	3.00	PLN/USD	
Expenditures, including:			
	'000 EUR	729,754	
Capture (CCP)	'000 EUR	458,350	
Transport	'000 EUR	124,910	
Storage	'000 EUR	146,494	
Expenditure eligible for EU grants			
	'000 PLN	2,919,016	
Max EU aid level	50%		
Expenditures for co-financing with EU grants	'000 PLN	1,459,508	
Deposit for storage facility protection	'000 PLN	0	
Deposit for storage facility protection	'000 PLN	0	
Grants			
EEPR grant	'000 EUR	180,000	<i>European Energy Programme for Recovery</i>
Maximum amount of grant from NER	'000 EUR	184,877	<i>New Entrance Reserve</i>
Norway Fund	'000 EUR	33,000	
Other grants for expenditures	'000 EUR	0	
Insurance during construction			
	'000 EUR	5,543	0.76%
Project engineer cost (1.5%)	'000 EUR	10,946	1.50%
Expenditures incurred by the Investor			
	'000 EUR	348,366	
Expenditures incurred by the Investor	'000 PLN	1,393,464	

EUR exchange rate in the relevant operating year	3.90	PLN/EUR	
USD exchange rate in the relevant operating year	2.90	PLN/USD	
System operation time in the relevant operating year	7,710	h/a	
Quantity of CO ₂ effectively captured in the relevant year	1,805	thousands of tonnes/year	CO ₂
Total operating costs	205,133	'000 PLN/a	
Costs of CO₂ capture	175,417	'000 PLN	
<i>Unit costs of CO₂ capture</i>	<i>97.2</i>	<i>PLN/tonne</i>	
Costs of electric energy for capture	72,069	'000 PLN	
Consumption of electric energy for the CCP	41.2	MWe	
Value of electric energy without CO ₂ costs	226.88	PLN/MWh	
Steam costs	69,777	'000 PLN	
Steam consumption	3,971,000	GJ/year	
Steam cost	17.57	PLN/GJ	
Water costs	2,798	'000 PLN	
Water consumption	270,303	m ³ /a	ELB
Water cost	10.35	PLN/m ³	price level 09', ELB
Chemicals	23,573	'000 PLN	
amines	2,746	kEUR	price level 09', ELB
activated carbon	357	kEUR	price level 09', ELB
other chemicals	2,941	kEUR	price level 09', ELB
Fixed costs of CO₂ capture plant	7,200	'000 PLN	
operating costs	4,050	'000 PLN	price level 09', ELB
HR costs	2,250	'000 PLN	price level 09', ELB

other costs	900	'000 PLN	price level 09', ELB
Costs of CO₂ transport			
Costs of CO₂ transport	24,640	'000 PLN	
Unit costs of transport	13.7	PLN/tonne	
Variable costs	6,160	'000 PLN	price level 09', ELB
Fixed costs			
operating costs	5,000	'000 PLN	price level 09', ELB
HR costs	2,000	'000 PLN	price level 09', ELB
other costs	11,480	'000 PLN	price level 09', ELB
Costs of underground storage of CO₂			
Costs of underground storage of CO₂	5,076	'000 PLN	
Unit costs of underground storage	2.8	PLN/tonne	
Electric energy consumption	1,460	MWh	ELB
Fixed costs			
unit operating costs	0.36	USD/tonne	
unit operating costs	0.27	EUR/tonne	
annual operating costs	489	kEUR	price level 09', ELB
HR costs	300	kEUR	price level 09', ELB
other costs	400	kEUR	price level 09', ELB
Municipal tax			
Municipal tax	5	PLN/tonne of CO₂	price level 09', DS. PGE
Operating insurance			
Operating insurance	1,451	'000 PLN	
Unit costs of operating insurance	0.8	PLN/tonne	

3.7.4 Operational costs

EUR exchange rate in operating year	PLN/EUR	3.90		
O&M costs	PLN/tonne			
- capture	PLN/tonne	97		
- transport	PLN/tonne	14		
- storage	PLN/tonne	3		
Municipal tax	PLN/tonne	5		
Operating insurance	PLN/tonne	1		
unit expenditure per tonne of CO ₂ of system efficiency	PLN/tonne	772		
replacement cost after 10 years	PLN/tonne	0	8.72%	nominal WACC of PGE
unit expenditure	PLN/tonne	772	1.25	project risk multiplier
Facility life cycle	years	10	10.90%	WACC with risk
			2.50%	inflation
Capital cost	%	8.20%	8.20%	
Depreciation	PLN/tonne	77.2	W. Rogowski <i>Rachunek efektywności przedsięwzięć inwestycyjnych (Investment project efficiency calculation)</i> Kraków 2006, Wolters Kluwer, p. 235, table 3.19.	
Financial part	PLN/tonne	38.9		
Total cost of capital per tonne of CO₂	PLN/tonne	116.1		
CO ₂			Cost of CO₂ capture and injection	
Market price of CO ₂ allowances in the relevant operating year	EUR/tonne	20.0		
Operating grant from support mechanism	EUR/tonne	40.4		

	Time of the experiment		
	2010 prices	10	15
PLN/tonne of CO ₂	245.03	216.85	203.79
EUR/tonne of CO ₂	62.83	55.60	52.25

Unit CO ₂ emission per GJ of brown coal	kg/GJ	108.74
Percentage of paid CO ₂ emission in the relevant operating year		100%
Net production without CCS	MWh	6,234,537
Annual emission from unit without CCS	t	5,844,341
CCS system efficiency	t	1,805,000
Net electric energy production proportional to captured CO ₂ emission	MWh	1,925,510
Fuel for production covered by CCS (brown coal)	MWh	4,610,897
Electric energy production losses to steam for CCS	MWh	307,547
Electric energy for CCS purposes	MWh	317,652
Total losses compared to production without CCS	MWh	625,199
Production of energy cleaned by means of CCS to KSE	MWh	1,300,312
Net energy production efficiency with CCS	%	28.20%
Unit CO ₂ emission per 1 MWh (net) without CCS	kg/MWh	937
Unit CO ₂ emission per 1 MWh (net) captured by CCS	kg/MWh	1,388
Avoided CO ₂ cost per unit of clean energy (net) after CCS	PLN/MWh	108
Cost incurred by PGE for “cleaning” from CO₂ per MWh (taking into account grants for CCS construction)		
CCS certificate we would like to obtain in the relevant year	PLN/MWh	218.65
Price of 1 MWh of energy from coal in the relevant year	PLN/MWh	300.00
Neutral price of 1 MWh of energy made “clean” after CCS (without CO ₂)	PLN/MWh	518.65

4 FINAL CONCLUSIONS

Execution of the demonstration CCS plant in Bełchatów would have a significant impact on the CO₂ capture technology development. The project, if successful, would allow for commercialization of the zero-emission lignite electricity generation.

R&D activities performed would allow for gaining an unique know-how since there is no CCS plant of this size in operation, combining all parts of the CCS chain, starting from CO₂ capture, through compressing, transportation finishing at storage sites. Experience gained would allow for solving many problems connected with CO₂ capture from carbon fired power plants flue gases. Here, lignite implies additional problems connected with instability of fuel parameters and as a result instability of flue gas processed. Operation of demo plant would also lead to evaluation of different factors influencing CO₂ capture from flue gas (e.g. SO₂ content, ash content, mercury content etc.). The results gained would allow to make decisions on constructing additional plants (e.g. more efficient SO₂ removal) in order to improve overall efficiency of the capture process.

The most important result from the Bełchatów project would be verification of CCS plant operation efficiency and stability in coordination with operation of the power unit.

Investment and operating costs of CCS are significant and would influence electricity prices in Poland. Economic calculations performed show that profitability of the project would require emission allowances prices to reach 50 EUR per tone of CO₂ emitted. Implementation of large scale CCS projects in Poland would than lead to electricity prices increase and in consequence would influence competitiveness of all Polish economy.

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