Carbon Capture and Storage Options for Power Generation in South Eastern Europe

Mr. Damir PEŠUT
Energy Institute Hrvoje Požar, Head of Department for Energy Planning, dpesut@eihp.hr

Mr. Mario TOT
International Atomic Energy Agency, Energy System Analyst, M.Tot@iaea.org

Mr. Robert BOŠNJAK
Energy Institute Hrvoje Požar, Senior Energy Analyst, rbosnjak@eihp.hr

Keywords

Carbon Capture and Storage, Power Generation, South Eastern Europe

a. Background

The conflicts of the 1990s led to the disintegration of a unified energy system in the South Eastern Europe (SEE). SEE region needed a framework in which it could cooperate on rebuilding energy networks, ensuring the stability to attract investments, and creating the conditions in which its economies can be rebuilt.

The important mechanism in which energy and power systems operate throughout the is the Energy Community (EC) and the ongoing and expected integration processes of the countries into the European Union's (EU) energy map.

Parallel to the evolution of the European internal energy market, the EU took an active role in promoting stability and sustainable development in SEE. The integration of the power market was the first initiative, later followed by the integration of gas markets and the harmonization of the legal framework for energy and environment.

In October 2005 the European Community and Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Montenegro, the Former Yugoslav Republic of Macedonia, Romania, Serbia and UNMIK on behalf of Kosovo signed the Treaty establishing the Energy Community. The Energy Community extends the EU internal energy market to South Eastern Europe on the ground of a legally binding framework. The Treaty entered into force on 1 July 2006. The EC contracting arties have committed themselves to implement the relevant *acquis communautaire*[1]. The Treaty includes key EU legal acts in the area of power, gas, environment and renewable energy. It is expected that all countries will become full member countries of the EU by the end of the planning horizon (i.e. by 2030).

[1] Legal and regulation framework of European Union

Figure 1: Countries to be referred to as the SEE area

Power markets in the South Eastern Europe are dominated by the national companies. Publicly owned companies control generation and distribution/supply assets. Power trade among parties is mainly bilateral.

Throughout the region there are private investors in the power generation area, primarily in the wind and other small scale renewable (in systems with feed-in tariffs). There is also a substantial interest in large scale coal and hydro projects, but there are very few committed projects.

Generation expansion in the region and development of SEE power market is influenced by energy projects in neighbouring systems (such as nuclear power programs in Romania, Bulgaria and Slovenia), foreseen connections to the Italian market, availability of natural gas from outside the region (SEE acts as a transit area to Western European Markets), future obligations in reduction and/or stabilization of GHG emissions, use of renewable sources and implementation of energy efficiency policies.

b. Aims

Objectives of the work presented were twofold. In one hand the objective was to consider development of power generation in the SEE area and estimate future role and competitiveness of the natural gas technologies.

On the other side objective was to asses the potential deployment of Carbon Capture and Storage (CCS) technologies in the SEE area for the period up to 2030. There are different aspects that could be considered in this evaluation (e.g. regulation, environmental, security) while the paper focuses on the techno-economic assessment.

CCS is one of the technologies under consideration for the reduction of carbon dioxide (CO_2) emissions and it is particularly suitable for power generation (i.e. for concentrated CO_2 emission sources). Development of CCS power plants is also of interest for the different activities in the gas and oil industries (e.g. transportation, Enhanced Oil/Gas Recovery, exploration activities) and certain synergies between gas/oil and power industries could be achieved by a careful and timely development of an appropriate regulatory framework for implementation of CCS projects.

c. Methods

The paper summarises results of the three studies [1-3] to which authors contributed since 2009. The first study [1] considers possible natural gas demand in SEE area and estimates feasibility of the envisaged regional gasification project subject to the natural gas supply from outside of the region (i.e. construction of transit pipelines for the Western European gas markets).

Natural gas markets in the SEE countries are relatively small in terms of current and future gas consumption. Inevitably, under such condition it is more difficult to develop and finance infrastructure for the natural gas supply. Case studies for the development of local gas networks (i.e. at city/town level) showed economic viability of the expansion assuming natural gas can be supplied (i.e. transported) to the region at reasonable cost.

To increase gasification in the SEE region large investments in the transmission infrastructure are needed in order to bring the natural gas to the SEE markets. To make transmission networks them acceptable, investments require immediate consumption after networks completion. In other words, development of the transmission networks requires simultaneous and coordinated development of gas power plants as "anchor" loads. Distribution networks then can build and gradually develop upon this base. The study has used power development scenarios developed in [5] to estimate the amount of gas demand in the power sector. To make the gas investments viable, one of the key finding was that minimum annual base demand of 2-2.5 Bcm is needed from the first year of operation of the new gas transmission infrastructure.

The second study [2] identified cornerstones in gas consumption, system by system, i.e. country by country. Apart for some industries (e.g. petrochemical), the main consumers of natural gas in the region could be power plants. Therefore a techno-economic model of the power generation expansion in countries under consideration was established using Wien Automatic System Package (WASP, [4]). The same model was used in the study [5], but this time authors assumed a more conservative (and in fact more realistic) approach in terms of slower development and full integration of the regional power market. Previously mentioned study [5] assumed completely integrated power market and power projects were purely based on economic viability. These assumptions led to a result in which large coal-based power plants were constructed in one sub-region while thermal power plants in other sub-regions were gradually phased out. The study [5] also neglected potential influence on expected future obligations on CO_2 emission reduction in the systems under consideration.

Study [2] analysed final natural gas demand for period up to 2030 based on the projections of the total useful heat demand (in households, services and industry) in the region. The final gas consumption was then complemented by the projected consumption of natural gas in power plants, refineries and non-energy sectors.

Analysis of energy demand in the base year (2006) started from International Energy Agency (IEA) statistics [6]. Energy balances of the countries were cross-checked and updated using the latest supplementary data collected by authors from different publicly available sources and reports. In some previous projects authors have conducted several surveys of the current energy demand patterns in the regions. These data were also used for energy demand analysis.

Demand analyses and projections were repeated for two economic development scenarios – reference (expected increase of Gross Domestic Product (GDP)) and pessimistic (lower increase of GDP). Analysis was done on country by country basis.

Development of the power market was assessed taking into account possible limits in CO_2 emission using country by country approach. Generation model was not integrated across the region, but limited trade options were simulated. Techno-economic model was used in iterations to take into account possible dynamics of natural gas network development. In this way, development of the gas transportation network in any sub-region was not possible before gas power plants were planned (i.e. before gas option was not competitive option in power generation in any particular sub-area).

Using projections for motor fuels and heating demand, oil refining capacities in the region were estimated and consumption of natural gas in those facilities was projected (energy for transformations). Non-energy consumption of natural gas in chemical and fertilizer facilities was also taken into account.

Finally the work presented in the study [3] was based on an integrated regional power system model taking into account interconnections between national power systems, as well as incorporating CCS options for coal and gas power plants. For this purpose a linear programming framework using International Atomic Energy Agency's (IAEA) Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE, [7]). A detailed model of the South Eastern Europe power system was developed comprising Croatia, Bosnia and Herzegovina, Serbia, Kosovo/UNMIK, Montenegro, Albania and Former Yugoslavian Republic of Macedonia. Connections to the neighbouring zones/systems were modelled as market nodes with predefined prices and interconnections' limits.

d. Results

Some countries under consideration have already almost fully exploited their hydro potential while some have large reserves of lignite. Different system wide and specific power plant (pre)feasibility studies give priority to the construction of coal based power plants using domestic, readily available and low priced lignite resource.

The general direction of national energy policies in the region is reaching a high degree of power supply security by the development of domestic resources (mostly coal and to the limited extent hydro) while constantly improving environmental compatibility of the power sector. The second sub-objective is of a particular interest as it opens a door to the natural gas power plant projects, especially from the point of view of CO_2 emission reduction potential as an interim measure in climate change combat. Other important advantages of gas power plants are their operational flexibility and speed at which those project can be implemented once the gas supply route is established (usually about 3 years which is much shorter compared to a large coal, hydro or nuclear project).

Following figure compares projected consumption of the natural gas for two scenarios – referent and lower GDP as it was estimated in [2].

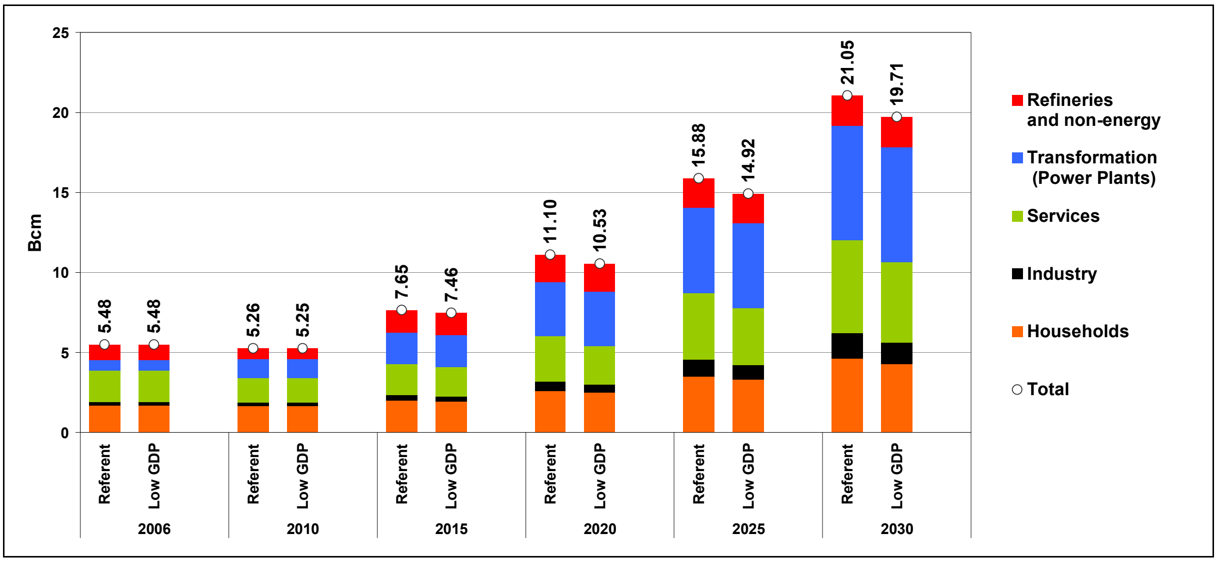

Figure 2: Projected total consumption of natural gas in SEE region (referent and pessimistic scenarios) until 2030 [2]

At the beginning of the period (2006 is the base year) the natural gas consumption was 5.48 Bcm and was projected to increase by 2030 to 21.05 and 19.71 Bcm, for referent and pessimistic scenarios respectively as presented in the next figure.

The highest relative increase in natural gas consumption is expected in systems in which gas networks are at the very beginning of the development. Absolute consumption in those systems will however remain below consumption in more mature markets. Total consumption will increase by almost four times from 2006 to 2030.

Final natural gas consumption (households, services and industry) in pessimistic scenario is expected to be 12% below referent scenario. At the same time, expected drop in the total natural gas demand is expected to be around 6%.

Almost all of the existing thermal power plants will be decommissioned by 2030 and will have to be replaced by new units. Gap between current power supply and expected increase of power consumption will have to be closed by the construction of new generation capacities.

The main generation options in the region are coal based thermal power plants and large hydro power plants. Current use of natural gas in power generation is limited due to the lack of gas networks. Only some sub-regions have suitable gas supply. But by 2020 gas network should be well developed. Development of large scale gas supply routes from Russia and/or the Caspian area are expected.

In [3] evaluation of the technical potential of CCS was done on all levels (capturing, transportation and storage capacity). A linear programming model was used to carry out techno-economic analysis.

Several scenarios were considered to analyse future power generation mix (free competition or reference scenario, national security of supply policies, market integration, limited CO_2 emission, CO_2 price/trade, subsidies for the development of CCS, stronger incentives for use of renewable sources and other). Following results were analysed and compared across scenarios:

- Structure of primary energy for power generation
- Structure of production capacity
- Structure of power generation
- Investment into new power plants
- Carbon dioxide emission (total and intensity per kWh)
- Total generation system costs (i.e. total discounted cost of operation and construction of power plants)
- Shadow prices i.e. marginal cost of power generation and
- Average production cost

Currently total annual emission from power generation in the SEE region is 55.2 Mt of CO_2, of which 50.5 Mt is attributed to the coal plants. Lack of local power production is evident.

Screening curve analysis showed that in the reference scenario the most competitive option was the conventional coal generation, followed by natural gas and nuclear options. If a CO_2 price of 25 USD per ton of CO_2 emitted is introduced, coal and nuclear options are close, followed by gas. CCS still rests above these. Further increase of carbon tax to 50 USD/ton CO_2 leaves nuclear as the most competitive, while the coal, CCS coal and gas options compete for the second place. As expected, the competitiveness of CCS gas options is heavily influenced by the natural gas prices. But from the investor point of view gas plants are more attractive as they are less investment intensive and are flexible in sitting and operation.

At the beginning of the period the region is net importer of power. Power import is expected to further increase until 2015. If plans for the development of local coal resources are to be realized by 2020 (less likely due to high investment needs), there could be a complete reversal of the situation and the region could become net power exporter.

Role of natural gas option in power generation can be significant, especially as a solution for a transition towards low-emission technologies (renewable, CCS, nuclear). Attractiveness of CCS options is directly related to the future GHG policies, while CCS in combination with Enhanced Oil Recovery (EOR) represents a promising technological option from the economical point of view.

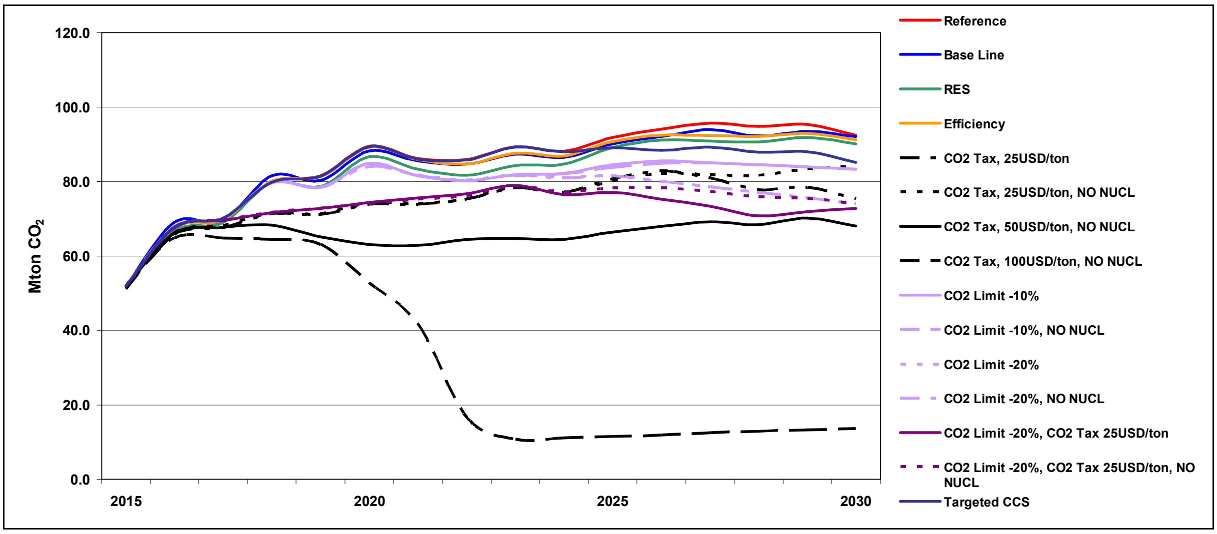

Figure 3: CO_2 emission from power plants in SEE area for different scenarios [3]

Under free market competition, annual CO_2 emission increases to 91.9 Mton in 2030, i.e. by 75%. Cumulative CO_2 emissions reach 1355 Mton. Under this scenario CCS option is not competitive. Inclusion of EOR option shows that CCS could be competitive without any further policies – i.e. it is competitive if coupled with oil/gas extraction. The EOR option assumed that an injection of CCS into existing oil/gas fields could yield a benefit of 40 USD per ton of CO_2 injected. The main problem in application of EOR is modest potential for EOR in the region and lack of regulatory framework.

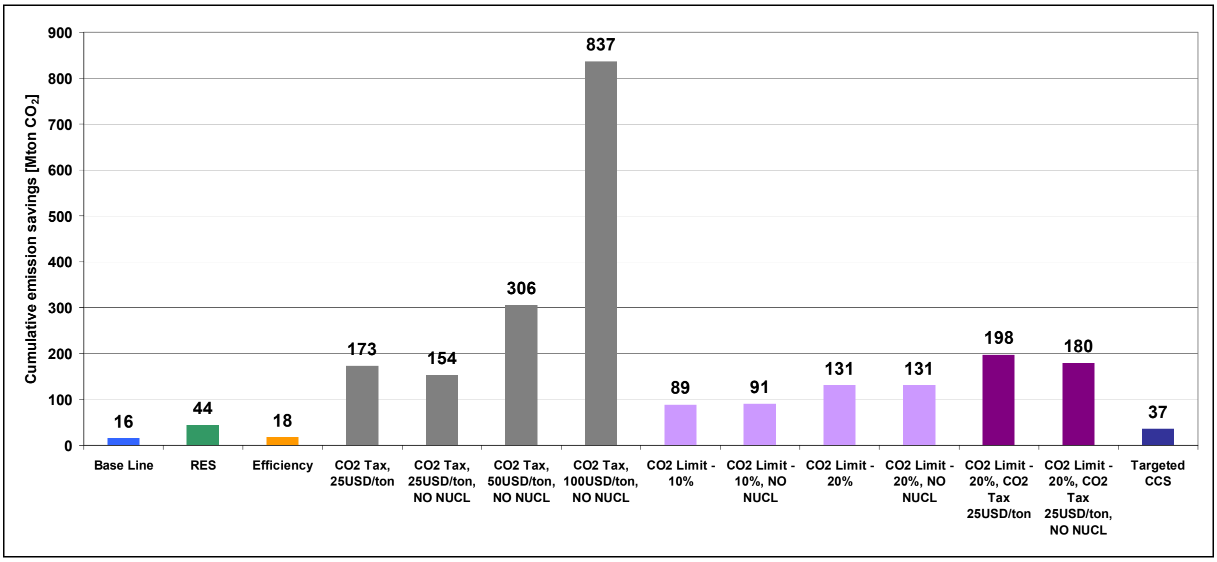

Figure 4: Cumulative CO2 emission reduction from power systems in SEE area for different development scenarios [3]

Business as usual, increased energy efficiency and renewable scenarios were used to compare the influence of different policies on total costs, CO_2 emissions and power prices. Under these scenarios CCS option was not competitive, but certain carbon emission savings could be achieved. At the same time average generation prices are higher compared to the free competition scenario.

The group of cases simulated under the CO_2 price scenario showed that CCS option becomes competitive when the CO_2 price reaches approximately 50USD/ton. At the same time alternatives like hydro and wind increased their share in total generation. Cumulative CO_2 emissions are decreased by 22% compared to the free competition scenario. By the end of the planning horizon approximately 63 Mton of CO_2 is stored underground. At the same time average generation costs increase by almost 50%. Marginal prices increase by 40%.

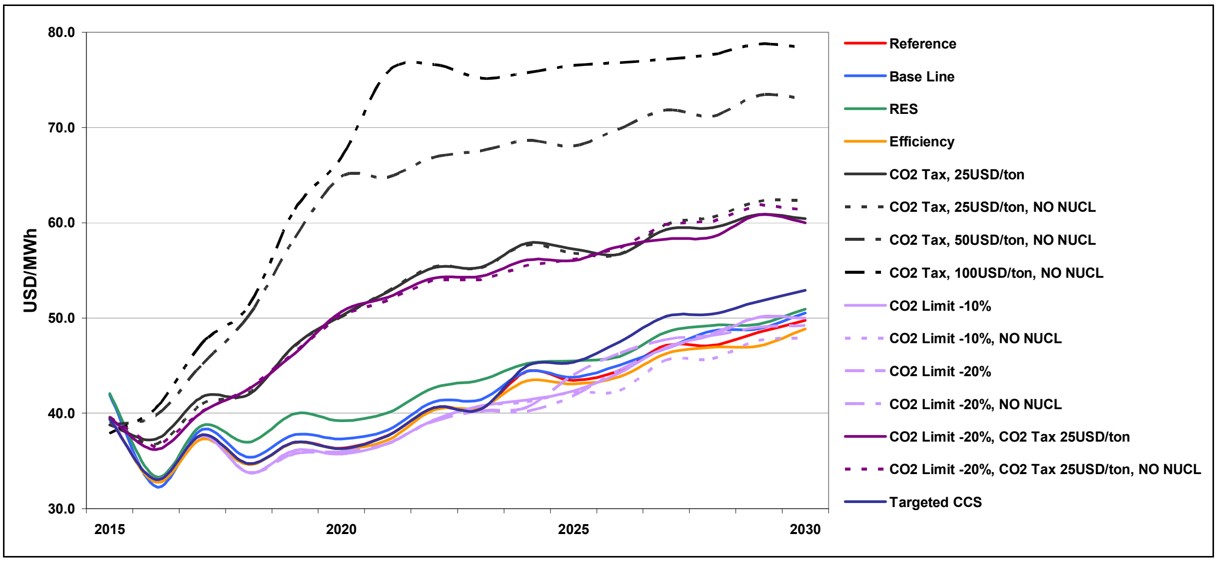

Figure 4: Average power generation costs in SEE area for different development scenarios [3]

An increase of the CO_2 price to 100 USD/ton leads to region-wide application of CCS option, including retrofit of existing and/or new conventional coal and gas units (i.e. retrofit of power units constructed between before 2020). At the end of the period practically all plants are equipped with CCS. Cumulative emissions drop sharply and are 62% below the reference scenario level. At the end of the period 650 Mton of CO_2 is stored underground, out of which 300 Mton is from CCS retrofitted plants. High carbon prices are followed by a further increase in average generation costs which are now more than 60% higher. Marginal prices are on average increased by 47% compared to the reference scenario.

e. Summary/Conclusions

CCS technologies will compete in the market with the nuclear alternative and their maturity and fast commercialization will be key elements. CCS combined with EOR could substantially change the picture and make CCS an attractive and strongly competitive alternative without further financial incentives (but appropriate regulatory framework must be set). Targeted development of certain number of CCS projects would require relatively large investments but would have a mild influence on average generation costs and could promote CCS and open-up the space for a faster deployment. At the same time additional research and field work is needed to verify the existence and suitability of underground formations for long term disposal of carbon dioxide.

e. References

[1] *South East Europe: Regional Gasification Study, Final Report*, submitted to The World Bank, KfW, PPIAF and ESMAP by: Economic Consulting Associates, Penspen, Energy Institute Hrvoje Požar, Untergrundspeicher und geotechnologie System GmbH, January 2009,

[2] *Estimation of the Potential of Natural Gas Market in Adriatic-Ion pipeline as part of the SEE EC Gas Ring* (available in Croatian), Energy Institute Hrvoje Požar, Zagreb, January 2011

[3] *Techno-economic assessment of carbon capture and storage deployment in power stations in the Southern African and Balkan regions*, Mario Tot, Damir Pešut, EIHP; Alison Hudges, Catherine Fedorski, Bruno Merven, Ajay Trikam, University of Cape Town; Jan Duerinck, Helga Ferket, Arnoud Lust, VITO; Study accomplished under the authority of the World Bank TEM/N93Q6/2011-0005, May 2011

[4] *Wien Automatic System Planning (WASP) Package, A Computer Code for Power Generating System Expansion Planning, Version WASP-IV with User Interface, User's Manual*, IAEA, Vienna, February 2006

[5] *Development of Power Generation in the South East Europe, Update of Generation Investment Study, Final Report*, Washington, Belgrade, January 2007

[6] IEA Energy Statistics available online at http://www.iea.org

[7] *MESSAGE – Model for Energy Supply Strategy Alternatives and their General Environmental Impacts, User Manual*, International Atomic Energy Agency, April 2008