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Study on Incentives to Build Power Generation Capacities Outside the EU for Electricity Supply of the EU

FINAL REPORT

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1. Executive Summary

1.1 Background and Objective

This report analyses the prospects for investments in power plants outside the EU dedicated to supplying the electricity they generate to the EU. Under the 3rd Emissions Trading Scheme (ETS), all CO_2 emission rights for new power plants installed within the EU will have to be auctioned. In contrast, for power plants outside the EU there are no costs for these rights. This provides a competitive advantage and opportunities for higher returns for power plant projects in countries bordering the EU.

The general objective of this study is therefore to analyse the impact of full auctioning on the investment decisions of power generators facing the option to invest inside or outside the EU. It will also clarify possible incentives to invest in projects under the UN CDM scheme outside of the EU to supply electricity generated from renewable energy sources into the EU. The question is whether electricity imported into the EU from fossil as well as renewable energy resources may cause globally increased CO_2 emissions. Unless stated otherwise, all of the following investigations apply only for *new* power plants to be built within the time frame of the 3rd ETS, i.e. *up to 2020*.

The analysis is prepared specifically for those EU member states that either already have electricity interexchange or at least have future electricity interexchange options directly across borders or overseas to non-EU countries (see table below).

EU countries with potential import from the following…	…non-EU countries
Bulgaria	Turkey, Ukraine, Former Yugoslav Republic of Macedonia, Serbia
Estonia	Russian Federation
Finland	Russian Federation
Greece	Libya, Egypt, Turkey, Albania, Former Yugoslav Republic of Macedonia
Hungary	Ukraine, Croatia, Serbia
Italy	Tunisia, Libya, Croatia, Montenegro, Albania, Bosnia-Herzegowina
Latvia	Belarus, Russian Federation
Lithuania	Belarus, Russian Federation
Poland	Ukraine, Belarus, Russian Federation
Romania	Moldova, Ukraine, Serbia, Turkey
Slovak Republic	Ukraine
Slovenia	Croatia
Spain	Morocco, Algeria, Tunisia

EU countries and their potentially electricity supplying non-EU neighbours

1.2 Demand for New Power Generation Capacities up to 2020

The need for new power plant investments up to 2020 in the selected EU countries is determined from the gap between the projected power plant capacities in 2020 less the already existing capacities that are no yet retired in 2020. The highest retirement rates are for coal power capacities of which 41% are due for decommissioning by 2020. Based on [EU Trends][1] it is anticipated that new power plant needs up to 2020 total over 150 GW, with almost 100 GW of this to be met by new renewable energy power plants. New coal power plant investments (26 GW) focus on North East European countries, wind power plants (50 GW) on Mediterranean countries and natural gas-fired power plants (12 GW) on South East European countries.

Italy, Greece and Finland are the only net electricity importing countries that are going to keep their importing status, at least until 2020. As such, they are preferred candidates for electricity imports from outside the EU. But as the analysis shows, in general all countries have considerable potential for new power plant capacity investments up to 2020.

1.3 Applied Methodology

Five fossil fuel-fired power plant options are investigated pair-wise inside and outside of EU countries, namely: a lignite power plant (base load), a hard coal power plant (base load), two CCGTs (one for base load and one for intermediate load) and a gas turbine (peak load).

To assess the economic viability of these options, an integrated user-friendly model under MS Excel has been developed for this study. It calculates the levelized electricity generation cost (LEC), including all cost categories that an investor has to consider in his investment decision. The LEC is calculated by summing the present value of all cost components divided by the present value of generated electricity. All cost series are calculated in real terms and discounted at a rate based on the weighted average cost of capital (WACC).

The WACC is based on 30% equity and 70% borrowed capital with typical rates for returns on equity and interest rate for bank loans. The decisive factor for the investor is a high rate of return on equity (ROE) .This comprises the following rates with typical values for projects in the power supply sector:

- a *risk-free return rate* which is identical to the bank interest rate
- a *venture premium* which is typical for power plant investments in EU countries
- a further *risk premium* which is dependent on the specific investment risk situation of the non-EU country in question.

The WACC includes also the corporate tax that is levied on the equity part of the invested capital.

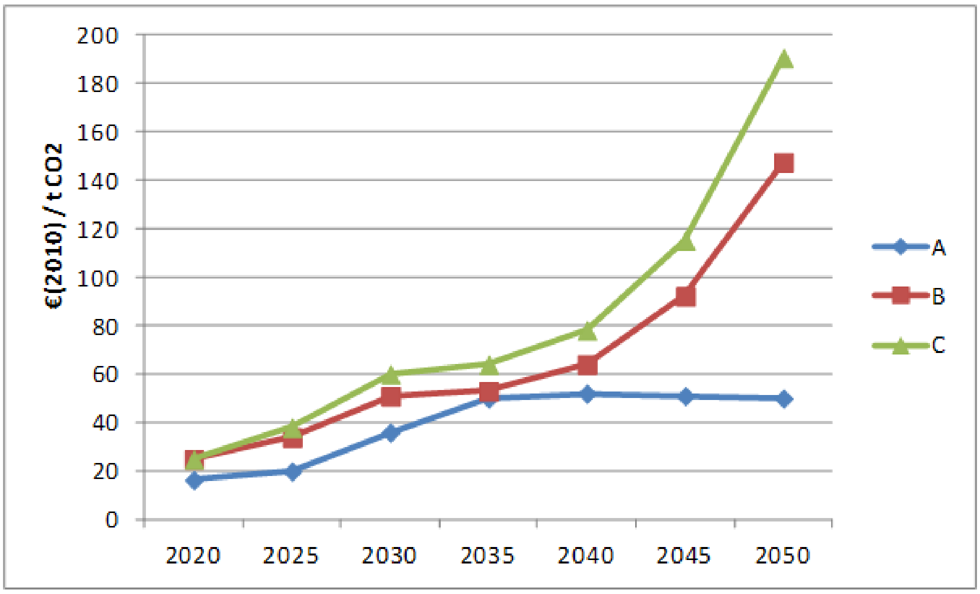
Economic and non-economic investment decision factors are analysed from the investor's viewpoint and are integrated into the model. The option that has the lowest electricity generation costs of a pair, with one located in an

[1] Square brackets indicate the source reference. All references are listed in section 9.

EU country and the other in a neighbouring non-EU country, is the preferred investment from the viewpoint of the investor.

Economic investment factors comprise mainly fuel costs and costs for acquisition of CO_2 emission allowances (“CO_2 costs”), both of which are derived from EU documents for the following three scenarios:

- ***Scenario A***: reference scenario reflecting a business as usual development with all EU policies up to March 2010 included, i.e. also legislation on ETS, non-ETS and renewables
- ***Scenario B***: decarbonisation scenario with -80% CO_2 in 2050 compared to 1990 in the framework of fragmented international climate action
- ***Scenario C***: decarbonisation scenario -80% CO_2 in 2050 compared to 1990 in the framework of global climate action



CO_2 prices in the three scenarios

Uncertainty regarding the future range of price developments is investigated with this scenario analysis. Whereas CO_2 costs tend to increase from Scenario A to Scenario C, fuel prices tend to decrease from A to C. This is consistent with lower global fossil fuel demand and thus lower fuel prices with greater efforts for CO_2 avoidance. Levelized fuel and CO_2 costs (levelized over the power plant lifetime) in real terms for a typical EU country are depicted in the table below.

		Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
	lifetime [a]	***35***	***35***	***25***	***25***	***25***
scenario A	€ / MWh_t	7.19	15.32	37.20	37.78	41.54
	€ / t CO_2	27.47	27.47	23.61	23.61	23.61
scenario B	€ / MWh_t	6.84	14.56	35.75	36.33	40.09
	€ / t CO_2	38.56	38.56	32.15	32.15	32.15
scenario C	€ / MWh_t	5.97	12.71	33.41	33.99	37.74
	€ / t CO_2	44.10	44.10	35.56	35.56	35.56

discount rate real 5%

Levelized fuel and CO_2 costs for a typical EU country (in real terms)

It is to be noted that there are significant differences with regard to fuel prices, corporate taxes and other financial conditions between the considered countries in the EU and those outside that may have some influence on the LEC. This is likewise addressed in the study.

1.4 Overview of Results of Fossil-Fired Power Plant Options

Under the assumption that the allocation rules of the 2nd ETS period would be applied over the whole lifetime of the power plants, investment conditions in the ongoing 2nd ETS period regarding emissions trading vary greatly depending on power plant type but also on EU country. In some countries a deficit of more than 50% of the required certificates remains after allocation, especially for coal power plants in Slovenia, Lithuania and Finland. On the other hand, gas turbines (GT) were effectively over-allocated with emission rights in Lithuania, Italy and Finland.

In the 3rd ETS period, full auctioning is the general principle applied for new power plants. The change from the 2nd to the 3rd ETS phase negatively affects combined cycle gas turbine (CCGT) plants the least. Because these, unlike simple cycle GTs, are not losing allocation privileges, but also, unlike coal power plants, they are not hit by high specific CO_2 emissions. Particularly if CCGTs are operated in base load, the change to the 3rd ETS period means that, on average over all investigated countries, only between about 7 and 11 €/MWh_e is added to their costs, depending on the scenario. But in the extreme case, the additional costs due to the change to full auctioning can be up to 72 €/MWh_e, as is the case for gas turbines in Lithuania under Scenario C. This gives an indication of the windfall profits that the 2nd ETS period released through national allocation plans.

Despite the full auctioning principle, lignite-fired power plants that emit the most CO_2 are still the most competitive base-load power plant option in the 3rd ETS, at least in Scenario A and, for some countries, also in Scenario B and even in C. However, in the global action decarbonisation Scenario C, the highest CO_2 prices combined with the lowest fuel prices shift the competitive advantage for base-load power plants generally towards natural gas-fired CCGT plants.

Pair-wise comparison of investment opportunities in countries bordering the EU is done on the basis of the levelized electricity cost, including costs for generation and for transmission of the electricity from the power plant outside the EU to the respective feed-in point of the high voltage grid in the EU. In a first stage, there is some initial screening: some power plant options of country pairs for which the power plant investment, the fuel supply for the power plant or the electricity transmission to the EU proved to be unfeasible have been excluded from further investigations.

Generally, among the remaining investment options, base load power plants provide the most attractive investment options, for two reasons:

1. Levelized transmission costs are lowest for the highest annual full-load hours.
2. Base load is the segment that is most attractive for the CO_2 intensive coal power plants and thus non-EU investments in coal power plants can take particular advantage of avoided carbon costs.

The results of the investigation for base load investments are shown for the reference Scenario A in the table below. The LECs are calculated with discount rates, excluding risk premiums that are usually around the same for the two adjacent countries. It is to be noted in this context that the *return on equity only* is about double the WACC in real terms. The tables show the levelized electricity cost (LEC) as a total as well as the included CO_2 cost (LCO_2) and the levelized transmission cost (LTC) per MWh of generated electricity. The tables also show the maximum discount rate based on the WACC that can be achieved up to the point of LEC equality between the power plants inside and outside the EU, i.e. up to the breakeven point.

Scenario A

Base Load

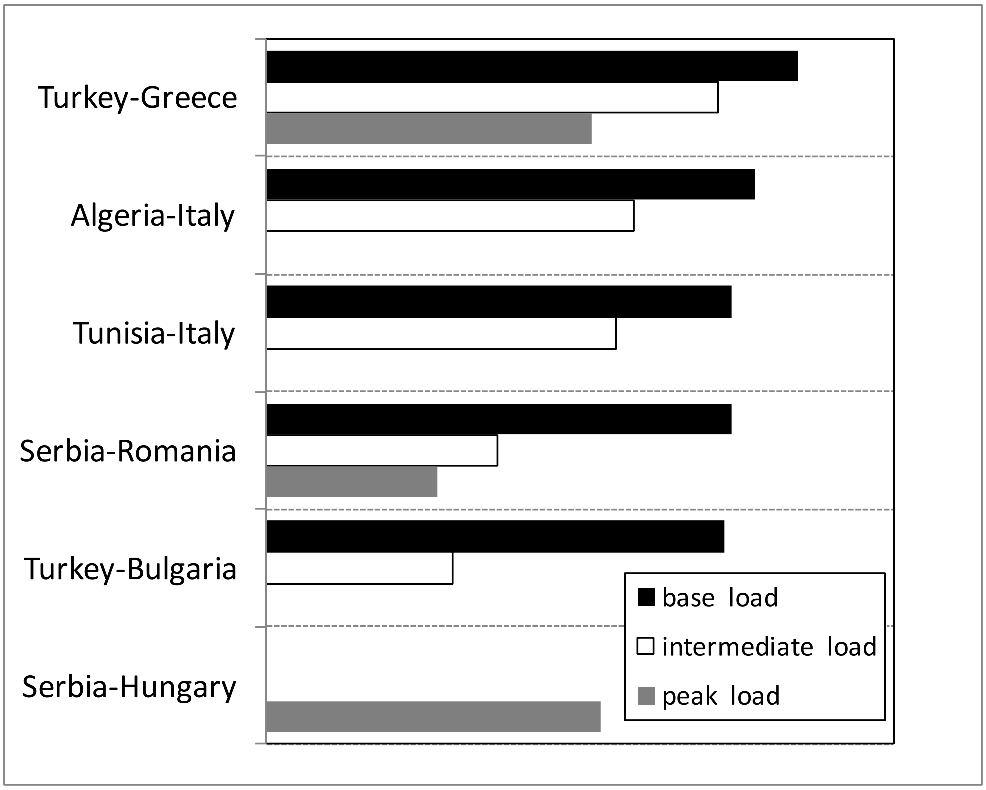
linkage: existing / new	EU country	EU power plant	EU LEC [€/MWh_e]	EU LCO_2 [€/MWh_e]	non-EU country	non-EU power plant	non-EU LEC [€/MWh_e]	non-EU LTC [€/MWh_e]	break even power plant	break even WACC real [%]
existing	BG	Lignite	71.0	26.2	TR	Lignite	47.4	0.4	Lignite	13.2%
existing	GR	Lignite	73.0	25.7	TR	Lignite	47.1	0.5	Lignite	13.8%
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	Hard Coal	82.1	20.2	TN	Hard Coal	69.3	9.4	CCGT	12.0%
new	IT	Hard Coal	82.1	20.2	ME	Hard Coal	66.8	8.6	Hard Coal	9.1%
new	IT	Hard Coal	82.1	20.2	DZ	Hard Coal	67.7	8.4	CCGT	12.8%
new	IT	Hard Coal	82.1	20.2	AL	Hard Coal	66.6	8.3	Hard Coal	9.5%
new	RO	Lignite	71.4	25.9	TR	Hard Coal	69.9	9.5	Hard Coal	5.5%
new	RO	Lignite	71.4	25.9	RS	Lignite	45.7	0.5	Lignite	13.5%

Overview of results for Scenario A for base load electricity

The outcome of the investigations can be summarized as follows: Coal-fired base-load power plants outside the EU possess a significant competitive advantage due to the avoided CO_2 costs. The achievable maximum rates of return (break-even WACCs, in real terms!) are quite high. It is to be noted, however, that the investor can only partially exploit these higher rates in order to achieve a competitive advantage over power plants within the EU. Even so, the residual rate of return will still remain quite attractive compared to what would be achievable for power plant projects within the EU. LTCs for new connections that require converter stations and transmission lines are quite high, but nevertheless the advantage from avoided CO_2 cost is still attractive, at least for base load. LTCs for existing connections are almost negligible compared to the generation cost, which is why such options have a strategic advantage and can even compete in peak load regimes with the EU power plant alternative.

Intermediate or peak load power plants outside the EU are less, respectively hardly attractive for investors. The reason is that levelized transmission costs for intermediate and peak load regimes are higher due to the low capacity factors. And also the CO_2 emission costs that can be avoided with a natural gas power plant by settling it outside the EU are lower compared to coal power plants. Such options become relevant only if natural gas prices are moderate (as in Maghreb countries) or if synchronized connections to the ENTSO-E grid are available and power transmission capacities not yet fully exploited (see Serbia and Turkey).

Scenarios B and C with higher CO_2 costs provide in general higher returns, especially for base load power plants. Over all three scenarios, six country pairs can be highlighted as the most competitive of the non-EU versus the EU power plant investment options:



Relative competitiveness of the most relevant investment options

Turkey, Algeria, Tunisia and Serbia are the most promising non-EU countries for new power plant investments that could profitably export electricity, preferably base load power, to EU countries. Greece and Italy and, of minor importance, also Bulgaria, Romania and Hungary may import such electricity.

1.5 Outcome of the Investigations of Renewable Energy and CDM Projects

There are significant differences between electricity from fossil-fired power plants and electricity from renewable energy sources. For renewable energy projects, the characteristic of the location is the most decisive factor for site selection. Renewable energy projects are viable at locations offering favourable natural resources like solar radiation and wind. Usually they are only economically viable if feed-in tariffs are sufficiently high or with other substantial promotion, which is typically the case in EU countries but less so outside the EU. A further important aspect is that renewable energy does not generate CO_2 emissions and no CO_2 costs, irrespective of whether they are installed outside or inside the EU. Under this aspect, there is no incentive for investing outside the EU for importing electricity into the EU. Additionally, transmission costs become higher with lower capacity factors as is typically the case for renewable electricity generation.

In general, we can conclude that importing electricity generated by renewable energy power plants in adjacent countries into the EU is currently not an attractive option for investors. It may become attractive, though, for large-scale solar energy projects that can exploit economies of scale for both power generation and power transmission. In this context, the planned DESERTEC project may be noted as a viable option for the medium term.

For the third trading period, the ETS Directive restricts the use of certified emission reductions (CERs) from new renewable CDM projects that are registered post-2012. However, this holds only as long as no satisfactory international agreement on climate change is approved by the Community or no bilateral agreement with a country is signed.

The CDM methodology of UNFCCC generally prohibits the approval of CERs for renewable energy (REN) imports into the EU. This applies, though, only in such cases where the REN power plant is directly and exclusively connected to a direct power line into the European electricity network or when the power purchase agreement of the power plant is directly contracted with a purchaser in the European electricity system. For other cases, i.e. with external intermediate electricity trading, indirect granting of CERs for renewable electricity import into the EU is possible in principle.

1.6 Double Counting and Carbon Leakage Effect from Electricity Imports into the EU

Electricity generated by an REN CDM project that is to be supplied to the EU increases overall global CO_2 emissions. The reason is that CERs issued for such projects could be used by installations included in the EU ETS. Thus, within the EU, these CERs would allow for higher overall CO_2 emissions on top of the ETS cap, justified as compliance with the emission reductions achieved outside the EU. But because of import of this electricity into the EU, the associated emission reductions are not actually achieved outside the EU. Under the line, emission reductions are double-counted. When added up over EU and non-EU countries, global CO_2 emissions are increased and the environmental and economic integrity of the EU ETS is undermined.

A similar case of increased overall CO_2 emissions arises if, instead of an REN plant, a fossil fuel-fired power plant in the non-EU country transfers its generated electricity into the EU. The imported electricity does not reduce the overall emissions inside the EU as fixed by the overall ETS cap. However, in the non-EU country CO_2 emissions are increased without having any further impact on the remaining electricity supply and the remaining CO_2 emissions in this country. This effect from fossil fuel-fired electricity import is known as carbon leakage.

Each electricity import into the EU – also from existing power plants – cannot contribute to less CO_2 emissions within the EU due to the fixed ETS cap, but could be used instead in the non-EU country to avoid other CO_2 emissions from power generation. And inversely, each electricity export out of the EU avoids power generation and usually also associated CO_2 emissions outside of the EU without any impact on the EU's own CO_2 balance.

2. Introduction

The revised EU Emission Trading Scheme (ETS) Directive stipulates that power producers will have to buy allowances necessary to comply with the ETS as from 2013. Contrary to the situation prevailing in the first and second period of the ETS, the cost of emitting carbon will then turn into real production costs for electricity producers.

While power producers in the EU will act on a level playing field, this is not likely to be the case for power producers outside the EU not facing carbon constraints which translate into economic and business related considerations. As a consequence, incentives arise in countries adjacent to the EU to invest in new power generation capacities designated to generate electricity for export to EU member states, provided technical and regulatory requirements allow. Such electricity could, in theory, not only provide competitive advantages to their producers/suppliers arising from the absence of comparable carbon constraints, but may be perceived as carbon leakage from the production of electricity generation possibly impacting on the stringency of the EU wide cap and undermining the objectives of the revised EU ETS Directive.

EU member states are exposed to a different degree and in a different manner depending on their geographical situation and their non-EU neighbours to potential electricity imports from non-EU countries. The electricity grid of some EU member states is very well interconnected with non-EU countries, while interconnection of these member states with other EU member states remains, for the time being, less developed. Others may consider building new cross border electricity transmission lines, in order to benefit from electricity imports generated outside the EU.

Another subject investigated in this study concerns investments in electricity generation from renewable energy outside the EU, if

- the electricity generated is to be supplied to the EU and
- the country, where the investment is undertaken, is entitled to issue Certified Emission Reduction units (CER) under the UN Clean Development Mechanism (CDM), set up in order to stimulate, among other things, emission reductions in countries not subject to mitigation efforts under the Kyoto Protocol.

In such a case, the following effects could accrue to the EU ETS:

a) to the extent this electricity is supplied to the EU, the demand for allowances is expected to decrease resulting in a lower allowance price. Of course, the overall quantity of allowances in the EU ETS remains unaffected.
b) CERs issued from such projects could be used by installations included in the EU ETS for compliance. In such a case and due to the fact described under a), emissions on top of the EU ETS cap will be offset. As a consequence, globally more CO_2 would be emitted than without the

CDM project. From the investor's point of view, these projects may turn out to be attractive, since additional income from the issuance and sales of CERs could be released.

In the light of these potential consequences of the European emission trading scheme leading to double counting or carbon leakage effects, this study analyses the impact of full auctioning on the investment decision of power generators facing the option to invest inside or outside the EU with a view to supplying electricity for consumption in the EU.

This analysis addresses in particular uncertainties in investment decision making. Uncertainty concerns the development of power prices, carbon prices, fuel costs and other investment decision factors. Also the regulatory framework and the investment conditions in the various countries adjacent to the EU are taken into account, as well as diverse electricity generation technologies, such as those based on fossil fuels, but also those based on renewable energy, like wind and solar.

The study provides an assessment of the economic and microeconomic effects of full auctioning on investment decisions of power generators that have the choice to build capacities for the supply of electricity to the EU inside or outside the EU. Based on these findings, a list of countries with the most attractive investment options is compiled.

The study also clarifies the incentives to invest in projects under the UN CDM rules outside the EU, which supply electricity generated from renewable energy sources to the EU and which would lead to double counting of emission reductions.

2.1 Structure of the Study

In preparation for the study, EU member states are identified that have high potential and a substantial need to invest in new power plant capacities. These countries may attract not only power plant investments within the country, but instead also investments in adjacent non-EU countries with the option to import electricity into the EU country under consideration.

Thus, in Chapter 3 the need for new power plant capacities in EU member states is determined by investigating the expected evolution of electricity demand and supply. This is done for those particular EU countries that either already have electricity interexchange or at least have future electricity interexchange options across direct borders or overseas to non-EU countries.

As a next step, the investment decision process for new electricity generation capacity investment options is investigated. Based on the key factors for taking investment decisions, a decision-making model is set up and presented in Chapter 4. The model calculates the levelized costs of electricity in EU member states. The model is then used in Chapter 5 for analysing investment conditions in EU member states, focusing in particular on the impact of the change from the second to the third emission trading scheme.

In Chapter 6, the prospects for investments in non-EU countries are investigated in comparison with associated EU countries to which the generated electricity shall be supplied. Relevant EU/non-EU country pairs and their power plant investment options are identified and compared pair-by-pair. The most promising investment prospects are ranked.

Then in Chapter 7 renewable power plants and the effect of double counting from CDM projects are investigated. Finally, Chapter 8 introduces current, planned and potential investments in new electricity generation capacity in the considered non-EU countries with the aim of supplying electricity to the EU. The Executive Summary is found in Chapter 1.

2.2 Analysed Countries

Analysis of power plant investment decisions is undertaken for the following EU member states:

- Bulgaria
- Estonia
- Finland
- Greece
- Hungary
- Italy
- Latvia
- Lithuania
- Poland
- Romania
- Slovak Republic
- Slovenia
- Spain

Common to these 13 countries is their possibility for electricity interexchange or at least future electricity interexchange options across direct borders or overseas to non-EU countries. Countries participating in the European Economic Area (EEA) are not considered non-EU countries for the purpose of this study.

In order to obtain a clear overview of the findings for individual countries, they are classified into three clusters:

1. North East European countries
This cluster includes six countries that have direct borders to Russia or to other former Soviet Union states (Belarus, Ukraine) in common. These countries are

- Estonia
- Finland
- Latvia
- Lithuania
- Poland
- Slovak Republic

2. South East European countries
The common characteristic of these five countries is that they have direct borders to one or more EU enlargement country in the Western Balkan region. Falling within this category are:

- Bulgaria
- Greece
- Hungary
- Romania
- Slovenia

3. Mediterranean countries
The remaining two countries belong to this cluster. They have a Mediterranean coast and in general have direct electricity interexchange options only via connections overseas, either to African or to Western Balkan countries. These countries are:

- Italy
- Spain

The classification of the EU countries and their general options for electricity import from outside the EU are illustrated in Figure 1. Pairings of EU countries and their neighbouring non-EU countries are considered. For each country pair, the non-EU country could potentially host power plants that are constructed with the purpose of supplying electricity to the belonging EU country. The investigated country pairs are listed in Table 1 and are also indicated by red lines in Figure 1.

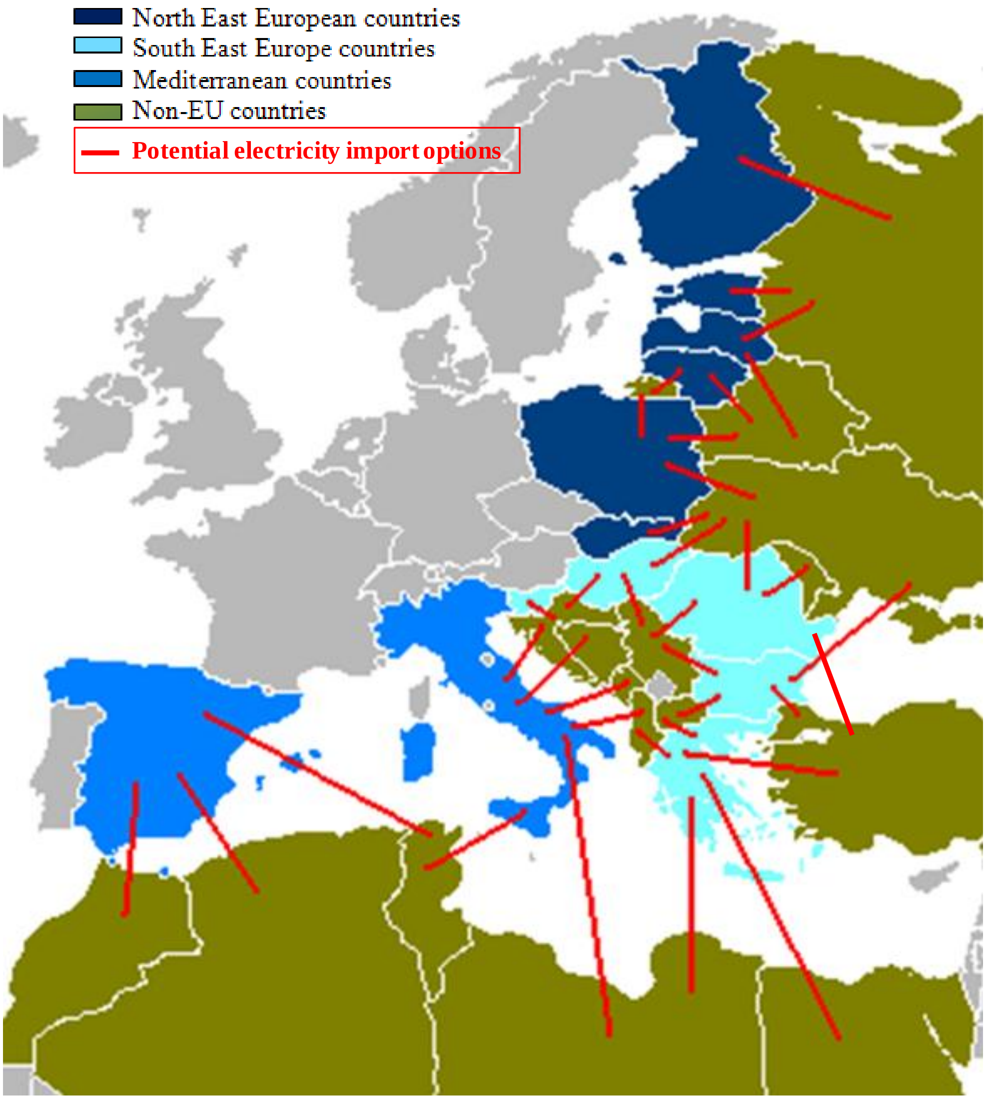


Figure 1: Overview of EU country clustering and potential electricity import options from non-EU countries

EU countries with potential import from the following...	...non-EU countries
Bulgaria	Turkey, Ukraine, Former Yugoslav Republic of Macedonia, Serbia
Estonia	Russian Federation
Finland	Russian Federation
Greece	Libya, Egypt, Turkey, Albania, Former Yugoslav Republic of Macedonia
Hungary	Ukraine, Croatia, Serbia
Italy	Tunisia, Libya, Croatia, Montenegro, Albania, Bosnia-Herzegowina
Latvia	Belarus, Russian Federation
Lithuania	Belarus, Russian Federation
Poland	Ukraine, Belarus, Russian Federation
Romania	Moldova, Ukraine, Serbia, Turkey
Slovak Republic	Ukraine
Slovenia	Croatia
Spain	Morocco, Algeria, Tunisia

Table 1: EU countries and their potentially electricity supplying non-EU neighbours

3. New Power Plant Capacity Needs

As a preparatory task for the study, the need for new power plant capacities in EU member states is determined by investigating the expected evolution of electricity demand and supply. This is done for those specific EU countries that either already have electricity interexchange or at least have future electricity interexchange options across direct borders or overseas to non-EU countries.

Electricity demand and supply in these EU countries is analysed under the following aspects:

- Electricity demand assessment:
  How will electricity demand in each of the selected countries evolve up to 2020?
- Structure of existing power plants:
  What power plant capacities are installed? And what is the age of the installed power plants? What will be the resulting power plant retirement plan up to 2020? An analysis of these questions is undertaken for each of the selected countries per power plant technology classified by fuel types.
- Development of power plant capacities:
  How could future power plant capacity evolve? This analysis concerns the development of total capacities by fuel type for each selected country and will include expectations on future replacement of retiring capacities as well as expectations on capacity net additions[2].
- Development of electricity generation:
  How much electricity generation can be expected from the power plants in the selected countries? A comparison with electricity demand for each country in 2020 will show whether the country will have to rely on electricity imports or on further power plant investments to fill the gap to demand or whether the country will not face an electricity deficit.
- Needs for investments in power capacities:
  What gross additions for power generation capacities are needed to obtain the expected power plant capacities in each selected country?

With analysis of all these aspects, those countries are identified that have high potential and the substantial need to invest in new power plant capacities. These countries may attract not only power plant investments within the country, but instead investments in adjacent non-EU countries with the option to import electricity into the EU-country under consideration.

[2] ‘Capacity net additions’ should not be confused with ‘net electrical capacity’. The latter term is defined for each power plant as its gross electrical capacity less the electrical power required for the operation of the power plant itself. ‘Net additions’ of capacities, though, refer to gross additions of new power plant capacities less decommissioned power plant capacities. ‘Capacity net additions’ are therefore identical to the effective overall capacity increase or decrease.

3.1 Data Sources

For the demand and supply analysis of the selected EU countries, the following data sources are used:

WEPP

The UDI World Electric Power Plants Data Base [***WEPP***] is a comprehensive, global inventory of electric power generating units. It states ownership, location, and engineering design data for power plants of all sizes and technologies operated by regulated utilities, private power companies, and industrial or commercial autoproducers in every country in the world. [WEPP] is maintained and re-issued quarterly in its entirety (including regional subsets) by the UDI Products Group of Platts, the energy information division of The McGraw-Hill Companies, Inc. The June 2011 edition contains, for EU countries, 41,980 and for European non-EU countries 6,293 power plant records.

EU Energy Trends

The 'European Energy and Transport - Trends to 2030' publication **[*EU Trends*]** was issued by the European Commission in 2003 with updates in 2005, 2007 and 2009. A consortium led by the National Technical University of Athens derived scenarios from a set of E3 models (energy, economy and environmental models) structured around the PRIMES energy system model. These scenarios consider current trends for population and economic development, including the recent economic downturn as well as the highly volatile energy import price environment of recent years. Economic decisions are driven by market forces and technology progress in the framework of concrete national and EU policies and measures implemented up to April 2009. This includes the European Emissions Trading Scheme (ETS) and several energy efficiency measures. In this way, energy scenarios for all EU countries and some adjacent countries are calculated for the time period up to 2030.

The latest scenario described in the 2009 update of [EU Trends] is the so-called 'Reference Scenario'. It includes policies adopted between April 2009 and December 2009 and assumes that national targets under the Renewables Directive [2009/28/EC] and the GHG Effort sharing decision [2009/406/EC] will have been achieved in 2020. As such, the Reference Scenario includes the mandatory national emission and energy targets set for 2020 and can thus serve as a benchmark for policy scenarios with long term targets. The Reference Scenario is therefore also used within the study at hand. Figures for electricity consumption, generation and capacities up to 2030 are compiled for each country.

Eurprog

The 'Power Statistics 2010' (formerly called 'EURPROG') [***EURPROG***] is the 38th edition of the statistical yearbook published by EURELECTRIC. It contains referenced data from EURELECTRIC members from all 27 EU member states for the years 1980, 1990, 2000, 2007, 2008, as well as forecasts for 2010, 2020 and 2030. It includes information on the structure of the electricity industries, trends in general economic indicators, peak demand and load management, medium and long-term generating prospects, sectoral electricity consumption, electricity balances and fuel consumption and emissions of the electricity sector.

The data provided in Power Statistics 2010 are based on estimates provided by EURELECTRIC’s Network of Experts on Statistics & Prospects. The latest issue of Power Statistics 2010 primarily contains data from 2008, although preliminary information on 2009 is partly integrated into the report. For this study also older issues of 2008 and 2009 are used and compared with the latest issue. Figures for electricity demand, generation and capacities for all selected countries for 2010 and 2020 are used for the purpose of this study.

Eurostat

Eurostat is the statistical office of the European Union. The ‘Electricity production and supply statistics report’ [***Eurostat***] was published in June 2011 and shows provisional 2010 data for electricity demand and generation in 2010 for each EU country. Electricity generation data are not classified by different fossil fuel types but contain an item ‘conventional thermal’ covering electricity generated from natural gas, coal and lignite.

Economist Intelligence Unit

The Economist Intelligence Unit is the in-house research unit of the magazine ‘The Economist’. For many countries of the world, it publishes an energy report that contains inter alia information on and scenarios for electricity capacities and demand in those countries. For this study, reports for different EU countries published between September 2010 and June 2011 are used [***EIU***], which provide estimates for the years 2009 and 2010 as well as forecasts for 2011 to 2015 and 2020. However, no reports for the Baltic countries (Estonia, Latvia, Lithuania) and for Slovenia were available. For the report at hand, [EIU] was used to countercheck and compare with figures from other data sources, but none of its actual information was used further in this report.

CIA

The ‘World Factbook’ [***CIA***] by the Central Intelligence Agency (CIA) of the USA offers statistics for electricity demand and generation for 2000 to 2008 and estimates of these for 2009 and 2010. It is updated weekly. Annual electricity generation is classified by country, but is not further broken down by energy source and fuel type. For the report at hand, [CIA] was used to countercheck and compare with figures from other data sources, but none of its actual information was used further in this report.

ENTSO-E

The European Network of Transmission System Operators for Electricity (ENTSO-E) is an association of 41 European transmission system operators (TSOs) from 34 countries. In its ‘Statistical Database’ [***ENTSO-E***] ENTSO-E provides statistical values for monthly electricity demand, generation and installed capacities from 2010 on backwards. These data are used to crosscheck values of other data sources for 2010. The statistical database is available online and was downloaded on 24 November 2011, but no schedule of latest updates is announced.

Data source comparison

In general, the data sources that were consulted can be characterized and compared under different aspects. The sources may contain information on electricity demand, electricity generation and/or power capacities (cf. Table 2). Only some of them provide also data for the year 2020, which depends on the nature of the data sources. Statistical data sources like [Eurostat] and [CIA] do not provide predictive figures for 2020. Other sources like [EU Trends] and [EURPROG] focus on scenarios. Their figures for 2010 are scenario-based and do not claim a strict statistical status for 2010. Other sources like [EIU] offer estimated figures and may be regarded as having an informational value located between statistics and scenarios.

Also the level of detail varies between the data sources, particularly with regard to breakdowns into different electricity generating technologies and the type of energy sources used. Some sources like [WEPP] provide full details of the fuel types used or at least distinguish between hard coal and lignite, such as [EURPROG]. Others like [EU Trends] only list all ‘coal’ in total or do not distinguish natural gas and coal fuels like [Eurostat], [EIU], [CIA] and [ENTSO-E] do.

Data Source	Available Details of Power Supply	Informational value of data	2010 Demand [GWh]	2010 Production [GWh]	2010 Capacity [MW]	2020 Demand [GWh]	2020 Production [GWh]	2020 Capacity [MW]
[EU Trends]	"Coal" in total	Prediction (based from 2009)	x	x	x	x	x	x
[EURPROG]	"Lignite", "Coal"	Prediction (based from 2009)	x	x	x	x	x	x
[Eurostat]	"Conventional thermal"	Provisional (based from 2010)	x	x	-	-	-	-
[EIU]	"Combustible fuels"	Estimation (based from 2010)	x	-	x	x	-	x
[CIA]	"Electricity in total"	Only for past years	x	x	-	-	-	-
[WEPP]	fully detailed	Statistical value	-	-	x	-	-	-
[ENTSO-E]	"Electricity in total"	Statistical value	x	x	x	-	-	-

Table 2: Characterisation of data sources used for this report

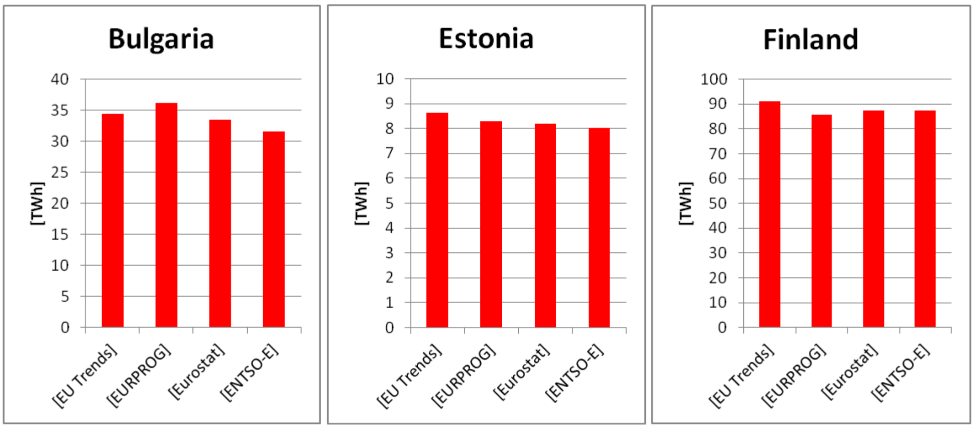
3.2 Electricity Demand Assessment

In order to analyse the electricity demand development for the selected EU countries, mainly four data sources were evaluated that provide electricity demand figures on a national level. These are (cf. Table 2):

- [EU Trends]
- [EURPROG]
- [Eurostat]
- [ENTSO-E]

Figures for 2010 in the 2010 issue of [EURPROG] are generated from a scenario that was set up for the status of data up to 2009. These can be compared with national electricity demand figures as given by [EU Trends]. Both sources also provide an outlook up to 2020 and beyond. For cross-checking the figures of both data sources, two further statistical data sources are used in order to compare demand values for 2010. This is firstly [Eurostat], for which data for 2010 are regarded as statistical values with a provisional status and, secondly, [ENTSO-E] that provides electricity demand statistics for 2010.

From the comparison with the two statistical sources, no preference for one of the two scenario sources [EU Trends] and [EURPROG] can be found. Whilst [EU Trends] seems to agree with the statistics in 2010 better for Bulgaria and Poland, [EURPROG] seems to perform better for Estonia, Greece, Slovak Republic and Slovenia (see Figure 2). For the other countries, deviations of the 2010 values compared to the statistical sources are either not significant or do not indicate a preference for one or the other scenario. Or the statistical sources are even contradictory, as is particularly the case for Lithuania and Spain.



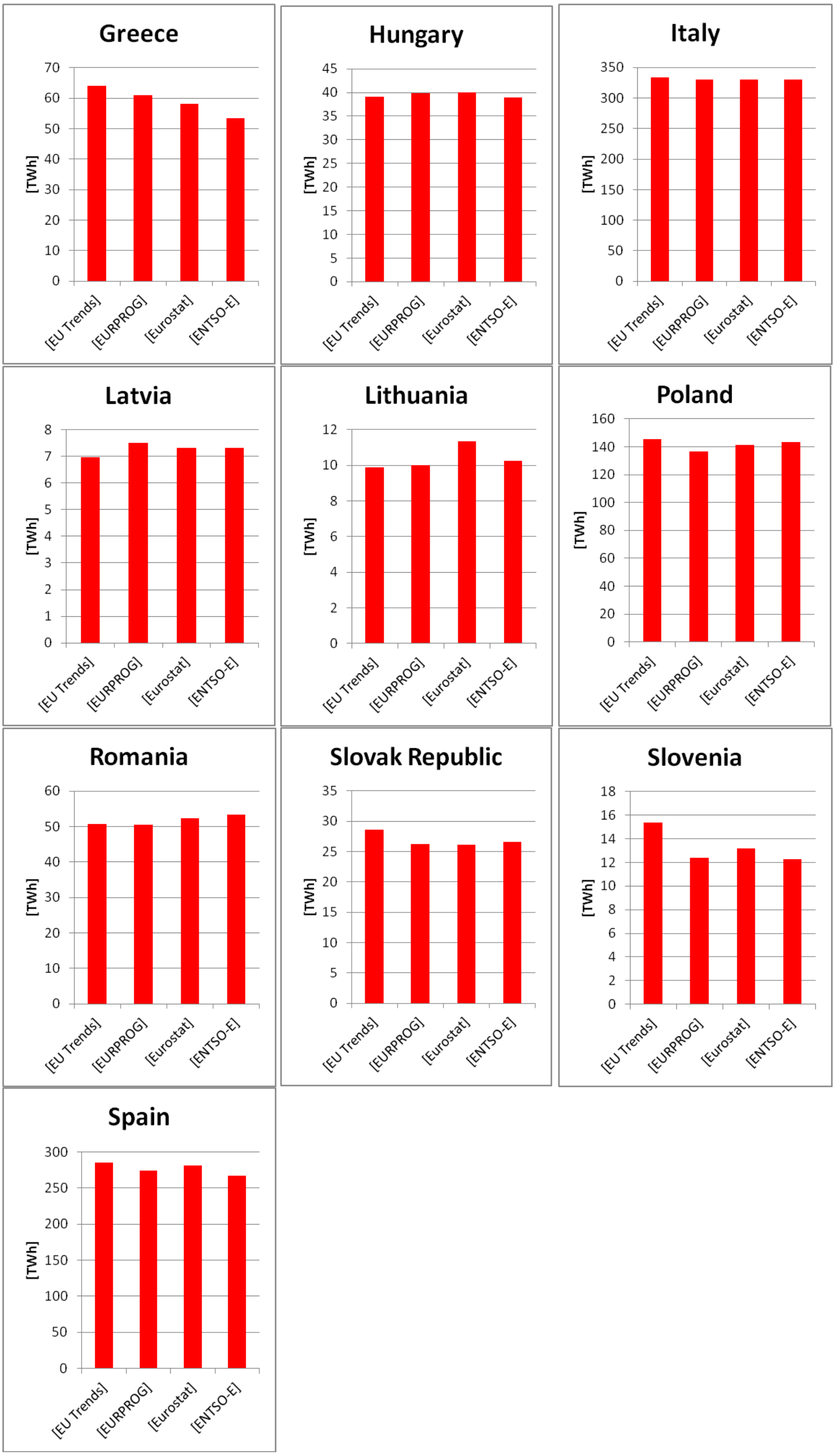


Figure 2: Electricity demand in 2010 according to different data sources

For 2020, only [EU Trends] and [EURPROG] offer demand figures for all selected EU countries. Since no preference in favour of one of the two sources could be identified from the comparison of 2010 values with statistical values, both sources are thus used in the following to analyse the evolution of future demand in these EU countries.

3.2.1 North East European countries

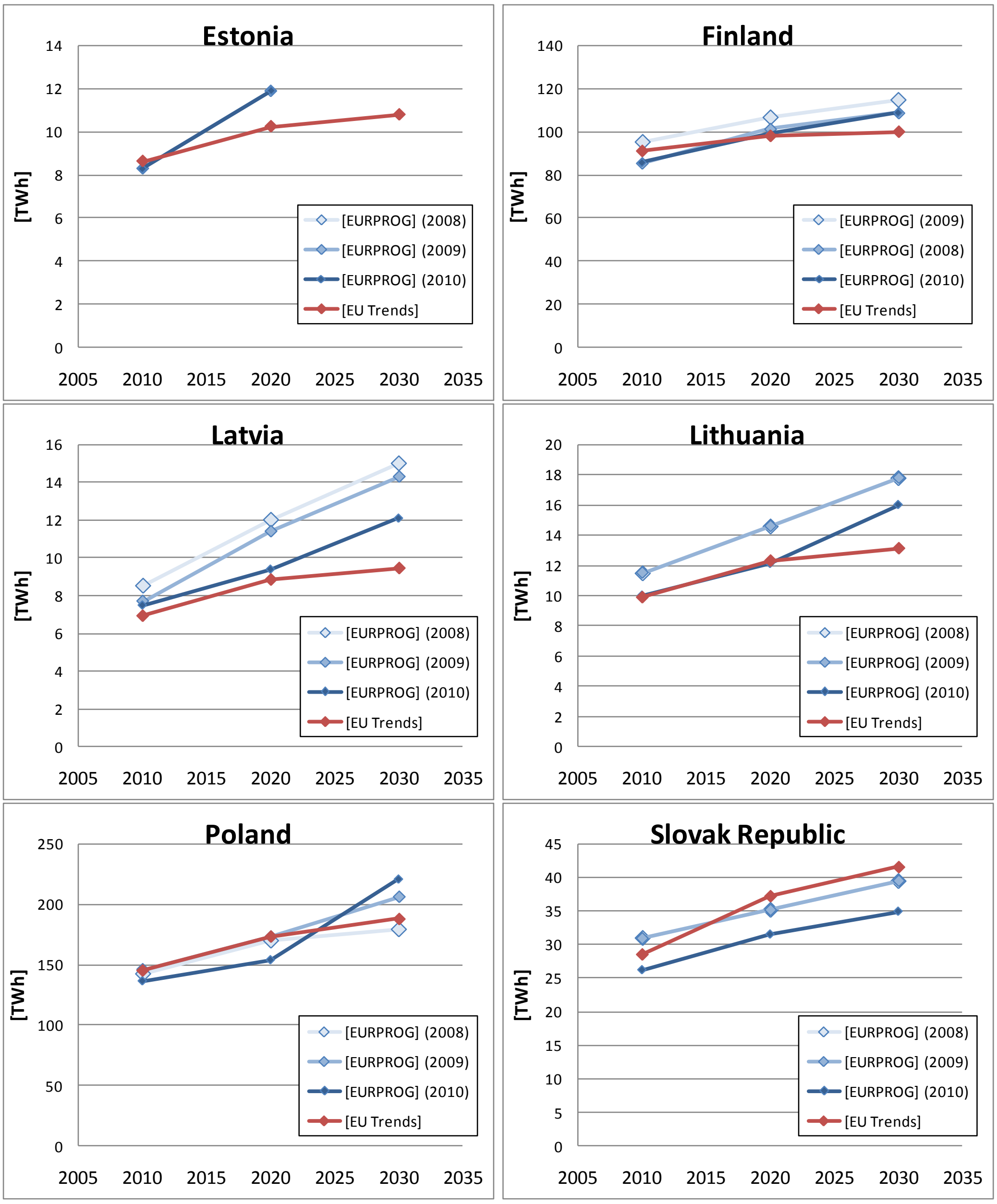


Figure 3: Development of electricity demand in North East European countries

Figure 3 shows the electricity demand in the North East European countries for the years 2010, 2020 and 2030. Demand figures as published by [EURPROG] in the years 2008, 2009 and 2010 are shown in blue, whereas figures from [EU Trends] are in red. Upon comparing the different [EURPROG] publications, it can be seen that a considerable reduction of electricity demand – not only in 2010 but also in 2020 – as a consequence of the global financial crisis and economic downturn is already included in the latest [EURPROG] issue of 2010. This is more or less also confirmed by [EU Trends]. However for Poland and the Slovak Republic, [EU Trends] seems more to follow the older demand paths from older [EURPROG] issues, which do not include the full impact of the global economic crisis. The strong increase in [EURPROG 2010] foreseen for Poland after 2020 may result from an inconsistency within the [EURPROG 2010]: Whereas forecasts up to 2020 are taken from the PSE Operator S.A. 'Development Program for Domestic Transmission System - Expected Scenario', projections for 2030 are estimates 'mostly based on assumed trends' presented in this scenario.

Nevertheless, according to both sources electricity demand increases are expected for all six countries and range between 8% (in Finland according to [EU Trends]) and 43% (in Estonia according to [EURPROG]) up to 2020 (cf. Table 3). In total, between 43.5 and 49.7 TWh/a additional electricity demand is expected in the North East European countries, a rise by 16% to 17%, depending on the scenario considered.

North East [TWh]	2010		2020		Increase		% Change	
	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]
Estonia	8.6	8.3	10.2	11.9	1.6	3.6	19%	43%
Finland	91.0	85.8	98.0	99.0	6.9	13.2	8%	15%
Latvia	7.0	7.5	8.9	9.4	1.9	1.9	27%	25%
Lithuania	9.9	10.0	12.3	12.1	2.4	2.1	24%	21%
Poland	145.4	136.7	173.5	154.1	28.2	17.4	19%	13%
Slovak Republic	28.6	26.2	37.2	31.5	8.66911	5.3	30%	20%
Total North East	**290.4**	**274.5**	**340.1**	**318.0**	**49.7**	**43.5**	**17%**	**16%**

Table 3: Development of electricity demand in North East European countries

3.2.2 South East European countries

Future electricity demand expectations in the South East European countries have likewise been subject to considerable downward corrections in the [EURPROG] issues from 2008 to 2010 (Figure 4). But the trends stay upwards, with demand increases to be expected as high as 46%, as is the case for Bulgaria according to [EURPROG] (see Table 4). [EU Trends] however forecasts only a demand rise by 8% in Bulgaria by 2020. For Greece, although hit hardest by the financial crisis, still an 18% to 19% electricity demand increase is foreseen up to 2020, depending on the scenario. In general, [EU Trends] expects for the South East European countries lower electricity demand increases up to 2020 than [EURPROG] does and expects in total about 34.1 TWh/a additional demand, a plus of 17%. [EURPROG] though expects in total about 51.5 TWh/a additional electricity demand in the South East European countries, a rise of 26% compared to 2010.

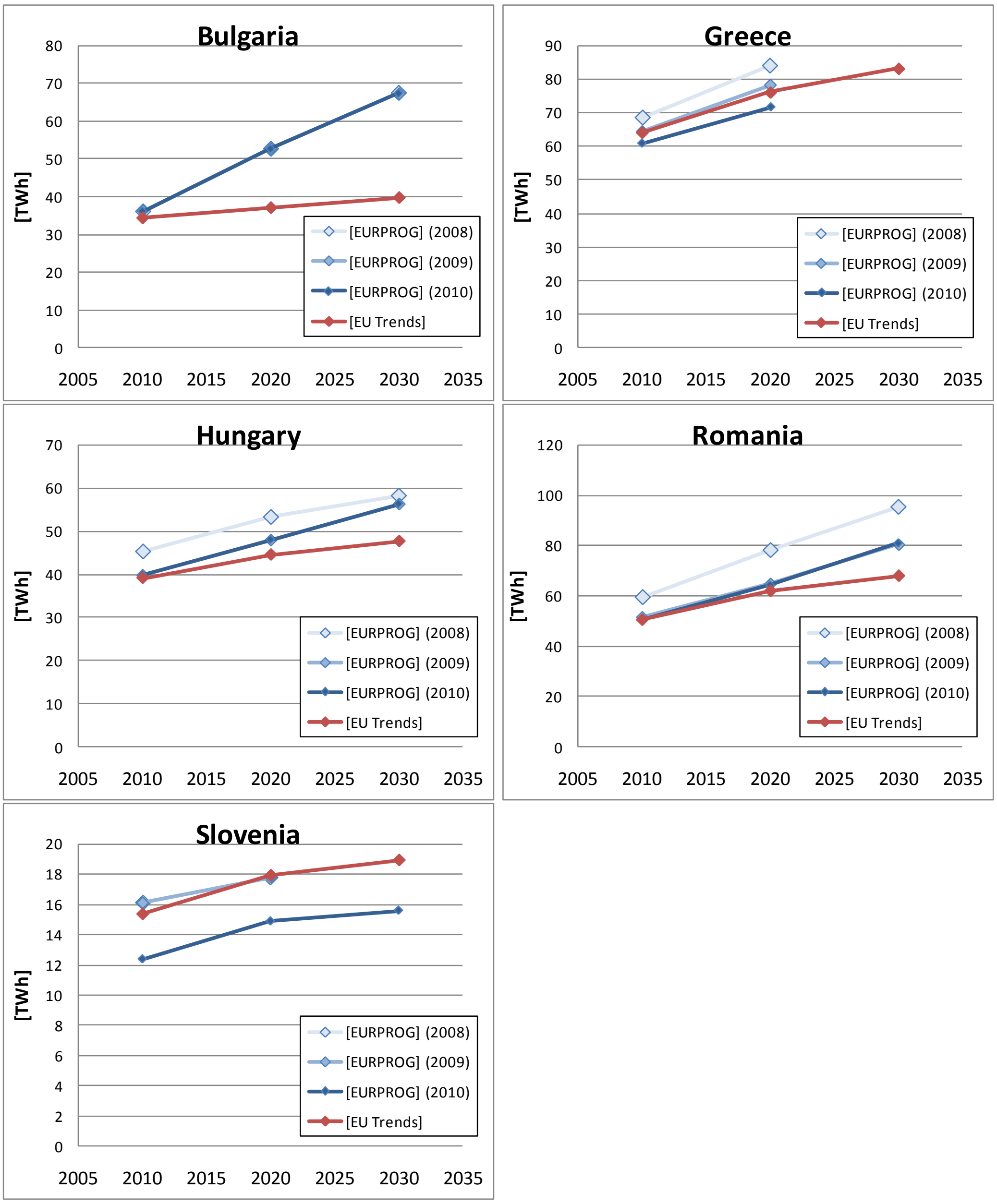


Figure 4: Development of electricity demand in South East European countries

South East [TWh]	2010		2020		Increase		% Change	
	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]
Bulgaria	34.5	36.2	37.1	52.7	2.7	16.5	8%	46%
Greece	64.1	60.9	76.1	71.7	12.0	10.8	19%	18%
Hungary	39.1	39.9	44.6	48.0	5.5	8.1	14%	20%
Romania	50.7	50.6	62.1	64.2	11.4	13.6	23%	27%
Slovenia	15.4	12.4	17.9	14.9	2.55733	2.5	17%	20%
Total South East	**203.8**	**200.0**	**237.9**	**251.5**	**34.1**	**51.5**	**17%**	**26%**

Table 4: Development of electricity demand in South East European countries

3.2.3 Mediterranean countries

The two Mediterranean countries considered, Italy and Spain, are also those with the highest electricity demand. Their demand figures are each on their own higher than those of either the North East European countries cluster or the South East European countries cluster altogether. Downward corrections of demand figures were made with the latest [EURPROG] issue in 2010, particularly for Spain (see Figure 5). [EU Trends] confirms the expected trend for Spain, at least until 2020, but believes in a much lower electricity demand increase in Italy, particularly beyond 2020. So again, as for the South East European country cluster, also for the Mediterranean countries [EU Trends] expects considerably lower electricity demand increases by 2020 than [EURPROG] does and expects in total about 111.6 TWh/a additional demand, a plus of 18% (Table 5). [EURPROG] though expects in total about 156.1 TWh/a additional electricity demand in the Mediterranean countries, a rise of 26% compared to 2010.

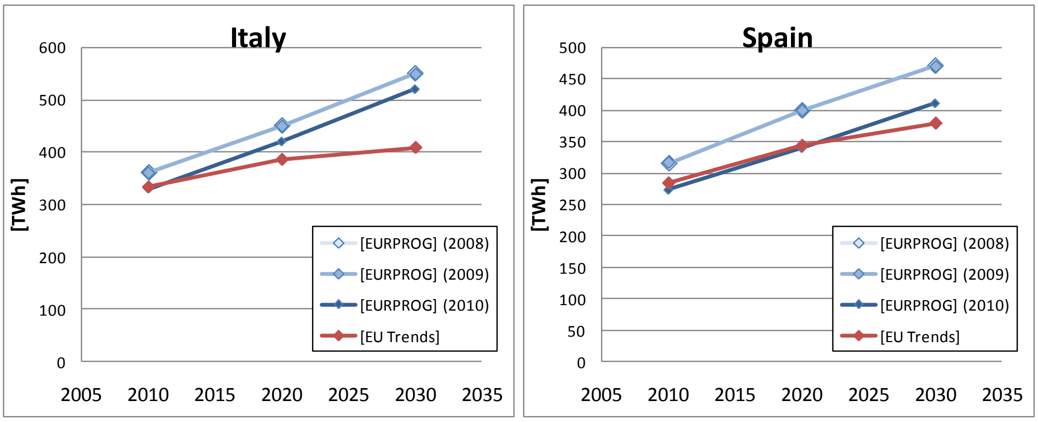


Figure 5: Development of electricity demand in Mediterranean countries

Mediterranean [TWh]	2010		2020		Increase		% Change	
	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]
Italy	333.3	330.5	386.0	420.4	52.6	89.9	16%	27%
Spain	285.1	273.6	344.0	339.8	58.9386	66.2	21%	24%
Total Mediterranean	**618.4**	**604.1**	**730.0**	**760.2**	**111.6**	**156.1**	**18%**	**26%**

Table 5: Development of electricity demand in Mediterranean countries

3.2.4 Summary: Electricity demand assessment

Although revised downward with the latest issues of [EURPROG], a considerable electricity demand increase of in total 23% (356 TWh/a) from 2010 to 2020 is still expected over all selected EU countries by [EURPROG], with outstanding demand growth particularly in Bulgaria (+46%) and Estonia (+43%). However, [EU Trends] does not confirm growth expectations for these two countries and foresees, particularly for Bulgaria, the lowest growth rate of only 8% by 2020. Also for Finland and Hungary, [EU Trends] expects similar low growth rates whereas [EURPROG] anticipates lowest demand dynamics not only for Finland (15%) but also for Poland (13%), and Greece (18%). In general, [EURPROG] foresees higher electricity demand increases and expects them to be more focussed to the southern countries, whereas [EU Trends] hardly identifies regional differences in the average growth rates of the country clusters (see Figure 6, Figure 1 and Table 6). [EU Trends] ends up with a demand increase of only 18% or 273 TWh/a for all selected EU countries altogether.

The quite different results from country to country, but also in sum, obtained from the two data sources, [EU Trends] and [EURPROG], cannot be explained. The reason is that neither the scenario methods nor the basis of expert judgement affecting the results of the two studies are transparent enough. This holds particularly for [EURPROG], for which the scenario may be obtained with different approaches and assumptions from the EURELECTRIC members in the various countries. [EU Trends] refers to a scenario framework that explicitly includes the latest climate policy measures on EU level but also the mandatory national greenhouse gas emission and energy targets set for 2020. So, to include the impact of these policies on the anticipated power plant investment behaviour in the proximity of the EU boundaries, the [EU Trends] scenario is taken as a reference for this study.

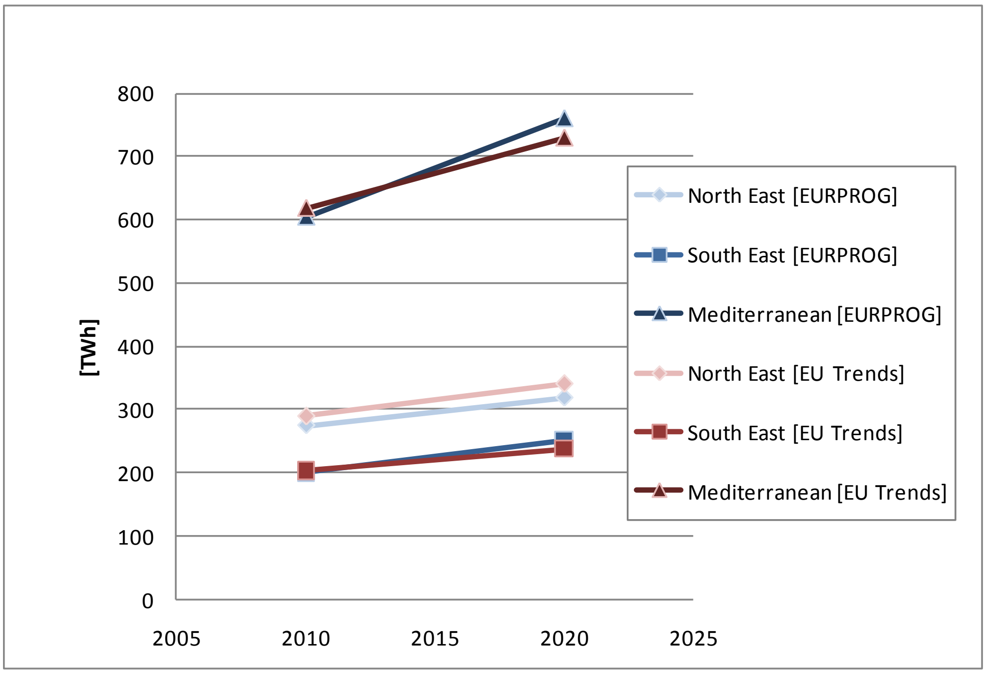


Figure 6: Development of electricity demand in total for the selected EU countries

Demand [TWh]	2010		2020		Increase		% Change	
	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]	[EU Trends]	[EURPROG]
North East	290.4	274.5	340.1	318.0	49.7	43.5	17%	16%
South East	203.8	200.0	237.9	251.5	34.1	51.5	17%	26%
Mediterranean	618.4	604.1	730.0	760.2	111.6	156.1	18%	26%
Total	**1112.6**	**1078.6**	**1308.0**	**1329.7**	**272.8**	**355.7**	**18%**	**23%**

Table 6: Development of electricity demand in total for the selected EU countries

3.3 Electricity Supply Assessment

The electricity supply assessment for the selected EU countries follows three steps. Firstly, the structure of the existing power plants by fuel type and by age is investigated, from which a retirement plan is derived. Secondly, the expected future development of power plant capacities is outlined. And thirdly, the expected future development of electricity generation is shown and compared with future demand expectations.

3.3.1 Structure of existing power plants

For analysis of the structure of existing power plants, the [WEPP] database is used, which is the most detailed and probably also most closely administered of the available databases. With the issue date of June 2011, [WEPP] belongs also to the most recently updated available data sources. It records for each power plant, inter alia, its gross capacity, its year of commissioning (‘year-on-line’), place and country of location, the utility type by technology and the type of main fuel as well as of alternative fuels.

Particularly due to the information on the age of the regarded power plants, the [WEPP] database is the only one among the available data sources that allows constructing a detailed retirement plan for the power plants by fuel type and by country. [WEPP] only lists gross electrical capacities in contrast to all other sources used in this study, which list net electrical capacities.

The retirement plan is obtained from the age structure of the power plant fleet by assuming standard technical lifetimes for each type of power plant characterised by its fuel type. The assumed standard technical lifetimes by fuel type are depicted in Table 7. For nuclear power plants, the lifetime was individually determined for each power plant, if specific information on planning for retirement was available. For others, no retirement up to 2020 was considered.

Fuel type	years
Nuclear Energy	individually
Coal & Lignite	45
Petroleum products	30
Gas	40
Biomass & waste	30
Hydro	60
Wind	20
PV	20
Other renewables	30

Table 7: Technical lifetimes of power plants by fuel type

3.3.1.1 North East European countries

The following six figures (Figure 7 to Figure 12) show the existing power plant capacities in the six North East European countries. They are classified by fuel type and by age, stated in 10-year steps. As can be seen, the predominant age of the power plants for most countries is in the range of 31 to 50 years. Only a few of the plants are older than 50 years, which is more than their technical lifetime and which may have been made possible in the past by technical retrofit measures.

Only for the Slovak Republic is it clear that large parts of the power plant fleet are younger than 31 years, particularly nuclear and hydro power plants. In Estonia there is the special situation that the majority of the power plant capacities are fired with oil-shale.

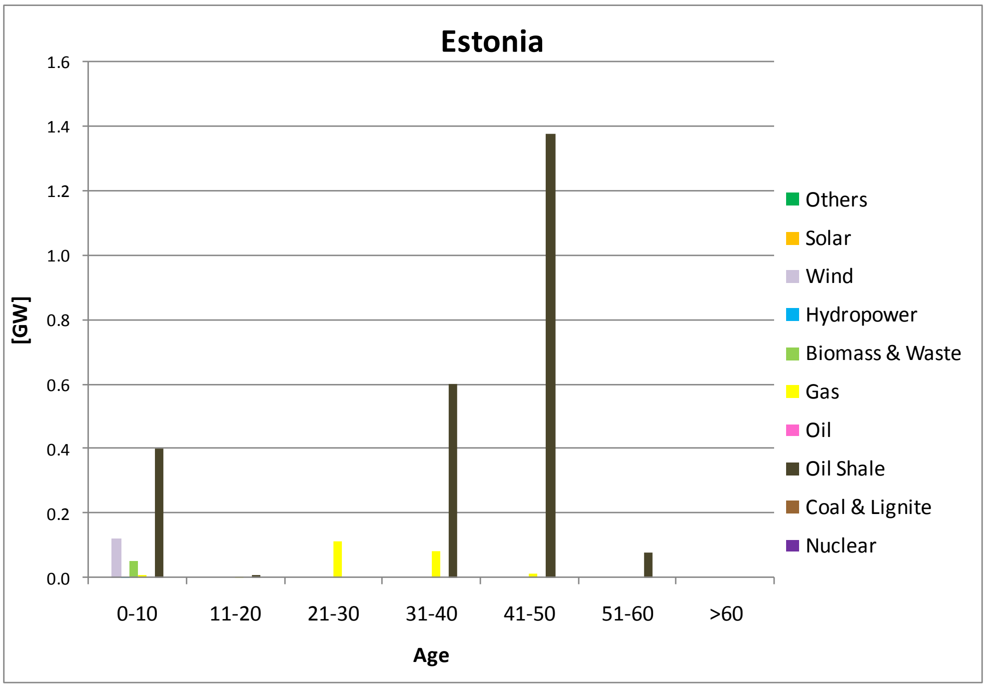


Figure 7: Age structure of existing power plants in Estonia

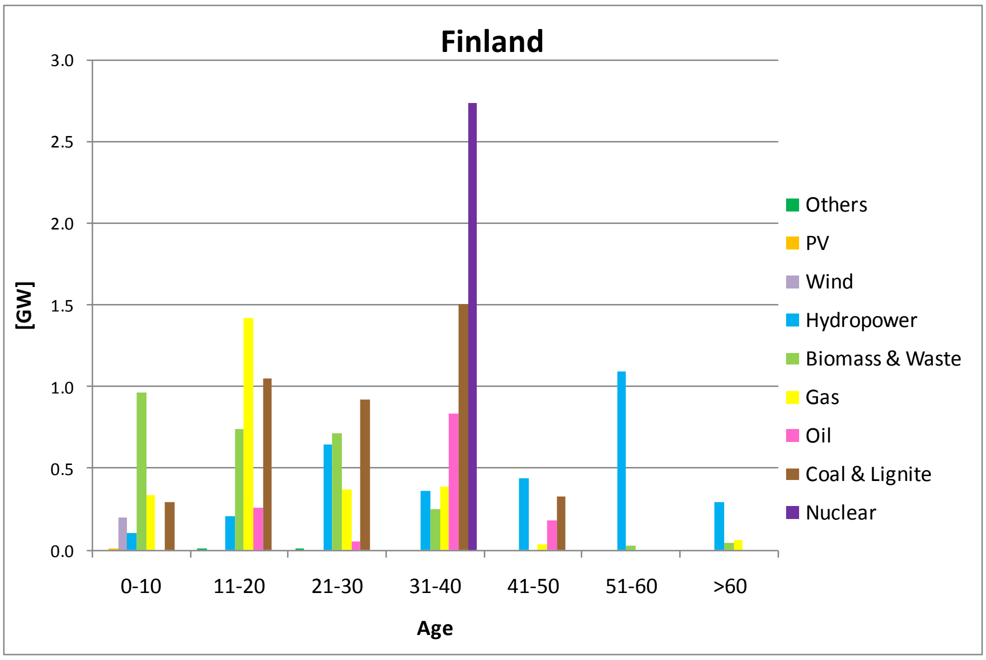


Figure 8: Age structure of existing power plants in Finland

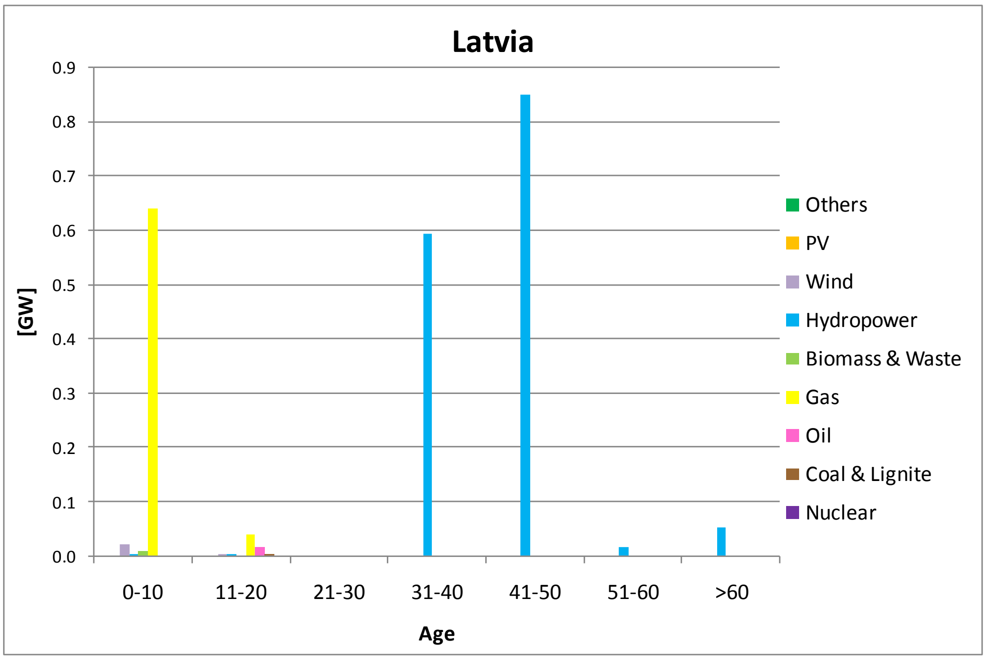


Figure 9: Age structure of existing power plants in Latvia

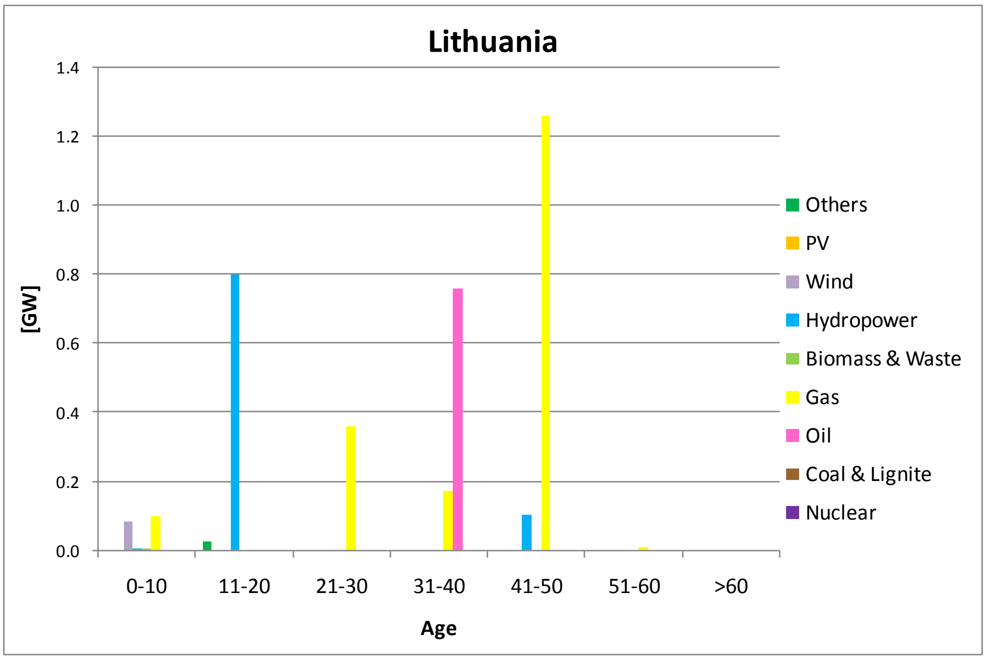


Figure 10: **Age structure of existing power plants in Lithuania**

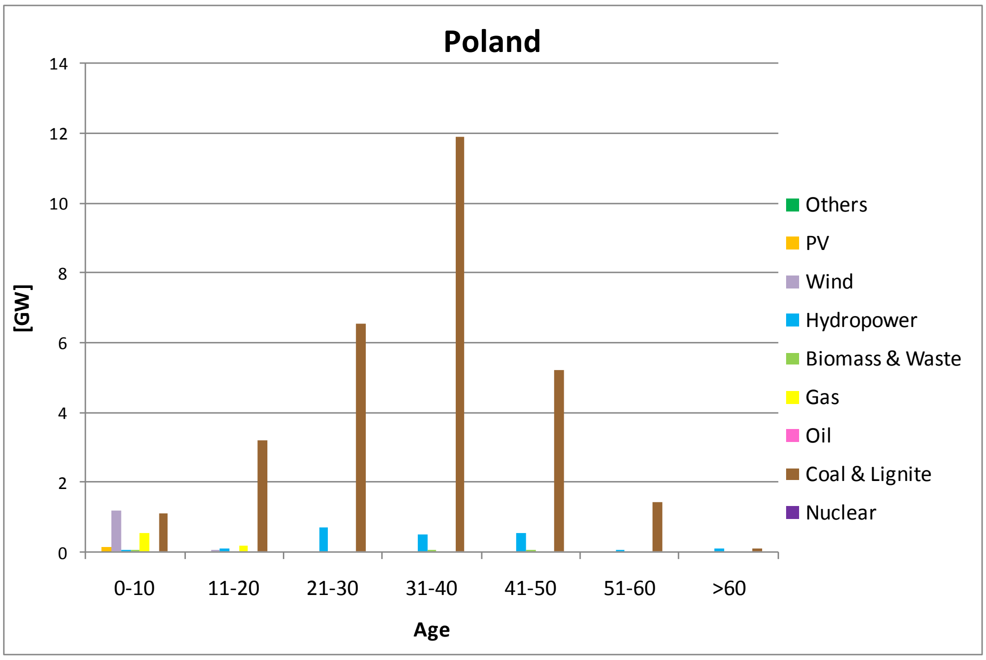


Figure 11: **Age structure of existing power plants in Poland**

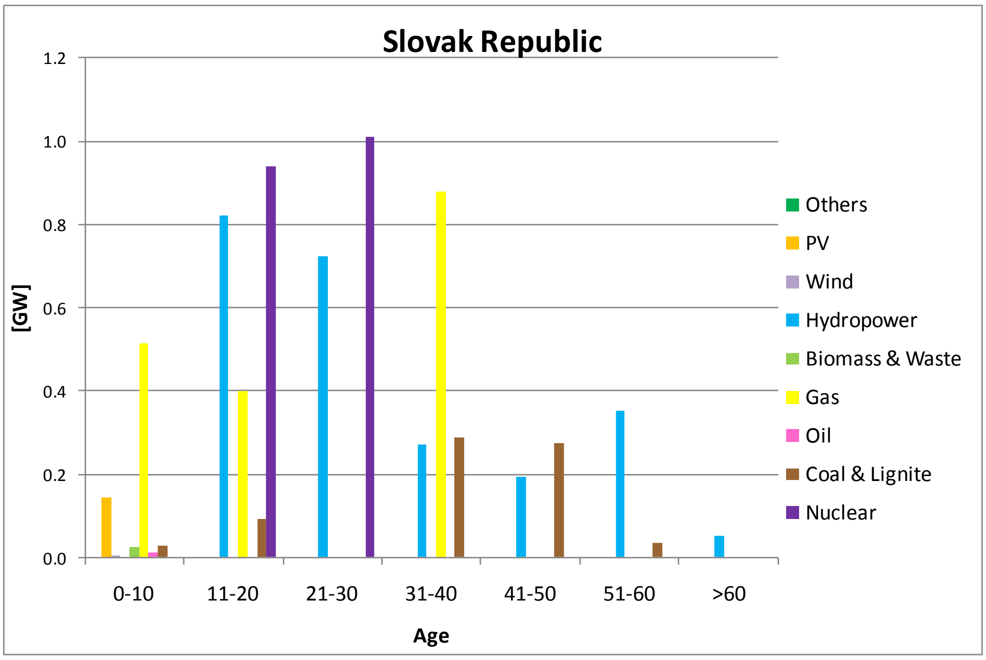


Figure 12: Age structure of existing power plants in the Slovak Republic

The retirement plans for the six North East European countries resulting from the age structure of their power plant fleets are depicted in Figure 13.

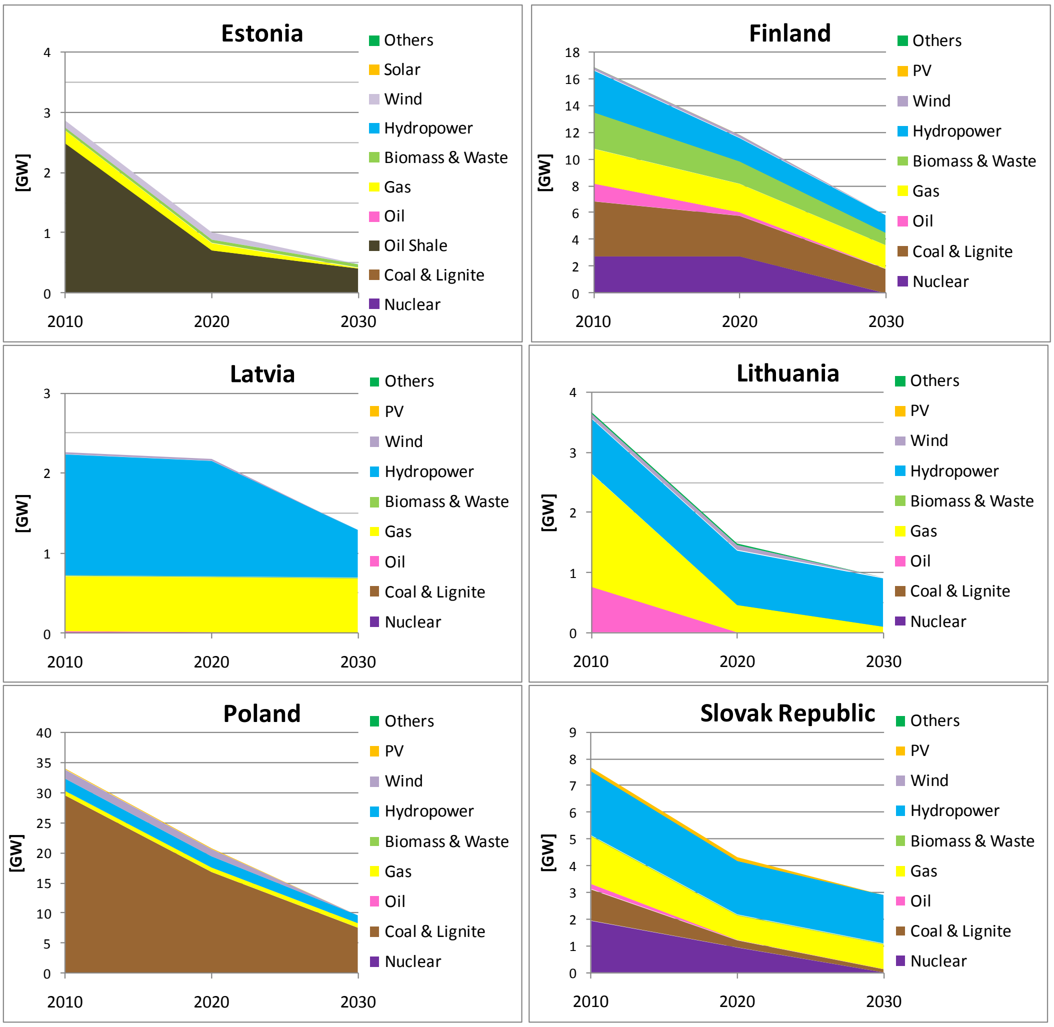


Figure 13: Capacity retirements in North East European countries

It becomes clear that the power plant fleets in Poland and Estonia are dominated by coal power plants and oil shale-fired power plants, respectively, whereas for Latvia and also for Lithuania and the Slovak Republic both, hydro and gas power plants play a major role. Finland in contrast has the most balanced mix of power plant types, with a considerable fraction being fuelled with biomass. Nuclear power is installed in Finland and Slovak Republic.

The largest relative power plant retirements up to 2020 are expected particularly for Lithuania and Estonia in accordance with the relatively high age of their power plants. Almost two-third of their electrical capacities may be retired by 2020 (cf. Table 8). But also the Slovak Republic, Poland and Finland face substantial power plant retirements by 2020 to a share of 30% and more. These three non-Baltic countries are at the same time the ones which have the highest power plant capacities installed. Thus the retirements in these countries dominate in absolute values for this cluster of North East European countries, with up to more than 13 GW being expected to retire just in Poland alone by 2020.

retirement	installed 2010 [MW]	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Estonia	2,864	1,863	65%
Finland	16,881	5,066	30%
Latvia	2,258	83	4%
Lithuania	3,677	2,200	60%
Poland	33,929	13,159	39%
Slovak Republic	7,685	3,369	44%
Total	**67,294**	**25,740**	**38%**

Table 8: Capacity retirements in North East European countries

Accordingly, the high share of coal power plants installed in Poland dominates the overall power plant retirements by fuel type (see Table 9 and Figure 14). About 14.7 GW of coal and lignite power plants are expected to retire by 2020, which is about 42% of installed coal power plant capacities. A higher share of decommissioning of 87% by 2020 is only planned for oil shale and oil-fired power plants, particularly in Estonia, Finland and Lithuania.

North East Europe	installed 2010 [MW]	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Nuclear	4,690	1,010	22%
Coal & Lignite	34,761	14,658	42%
Oil Shale	2,478	1,770	71%
Oil	2,304	2,013	87%
Gas	7,935	2,898	37%
Biomass & Waste	2,888	1,059	37%
Hydropower	10,001	2,022	20%
Wind	1,916	301	16%
Solar	285	0	0%
Others	36	9	25%
Total	**67,294**	**25,740**	**38%**

Table 9: Capacity retirements by fuel type in North East European countries

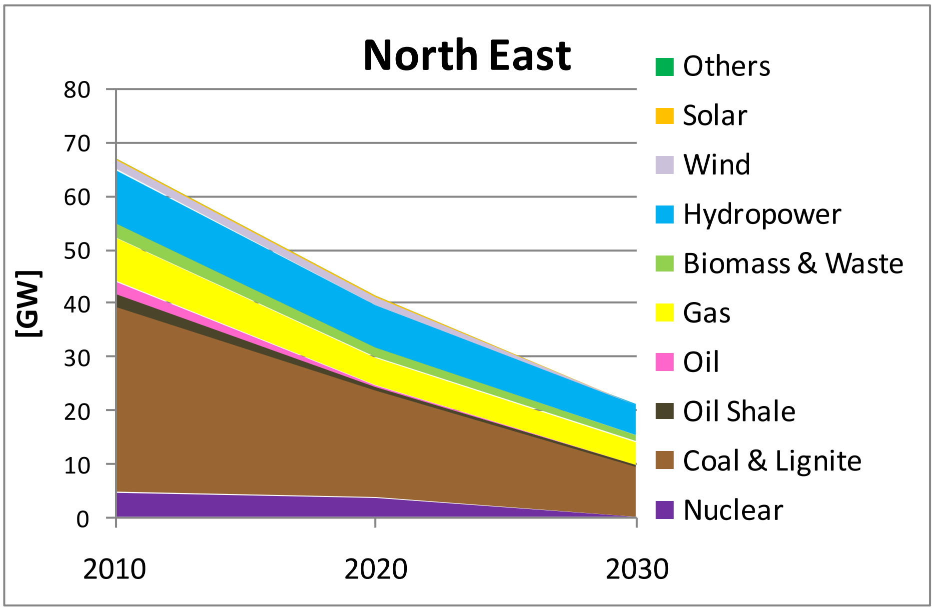


Figure 14: Capacity retirements in North East European countries

3.3.1.2 South East European countries

The following five figures (Figure 15 to Figure 19) show the existing power plant capacities in the five South East European countries. They are classified by fuel type and by age, stated in 10-year steps.

Bulgaria but also Romania and Slovenia are found among the South East European countries with the oldest power plant fleets. Greece and Hungary have relatively high shares of younger power plants, i.e. with an age of 20 years or less, which are mainly natural gas fired. The natural gas power plants in the South East European countries belong in general to the latest power plant technology installed. Installed nuclear power plants are mainly in an age range of between 11 and 30 years.

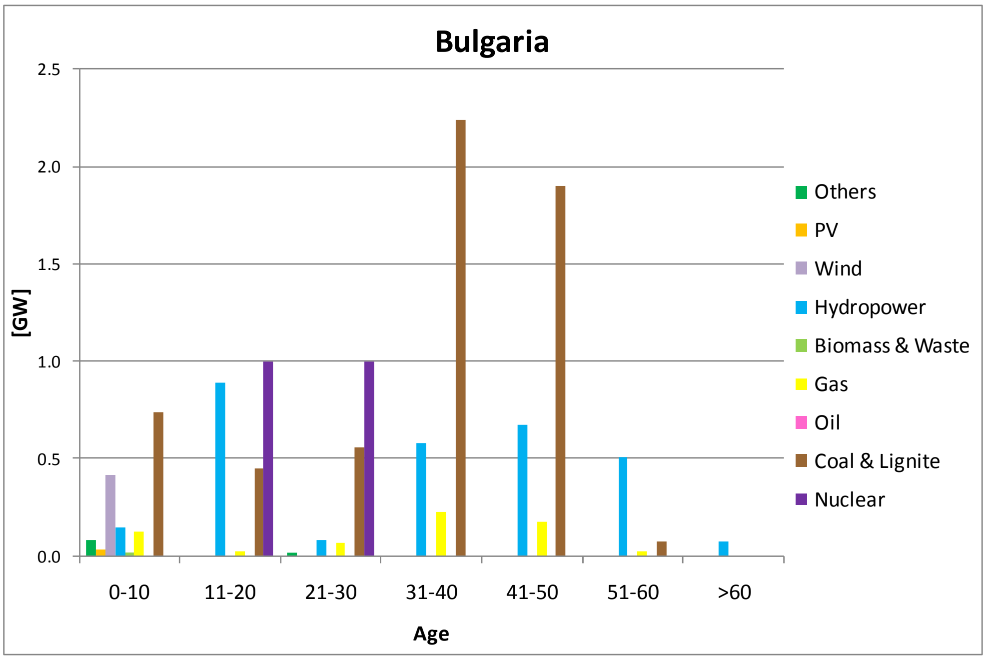


Figure 15: Age structure of existing power plants in Bulgaria

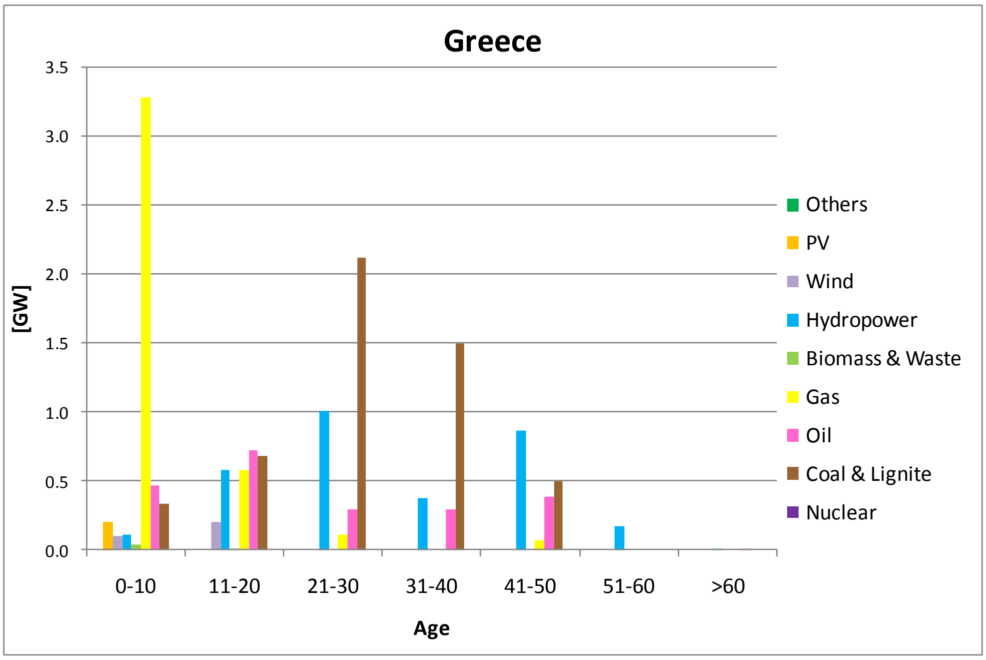


Figure 16: Age structure of existing power plants in Greece

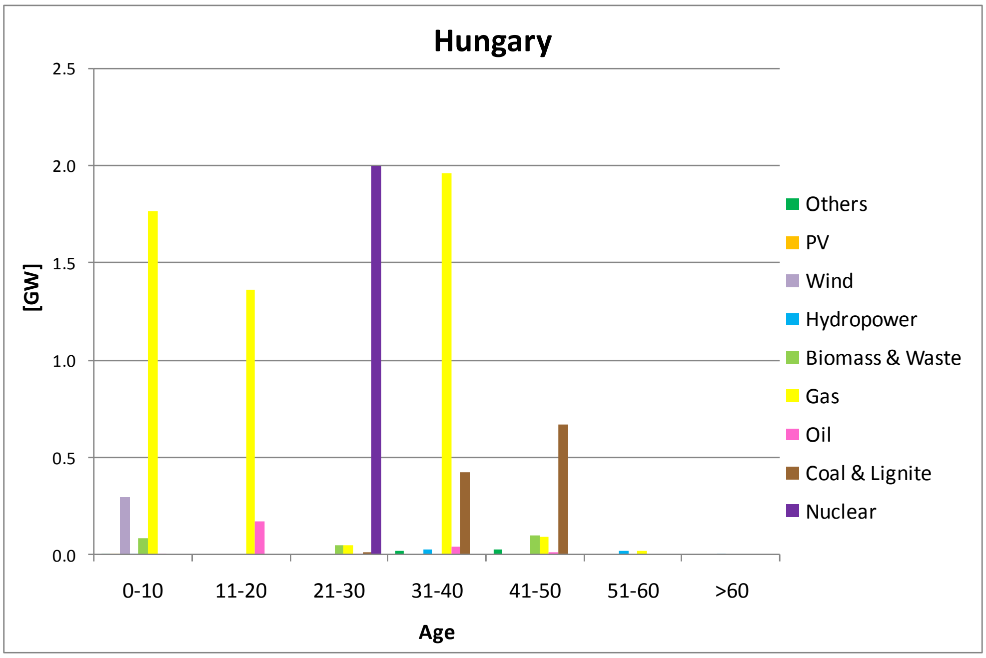


Figure 17: Age structure of existing power plants in Hungary

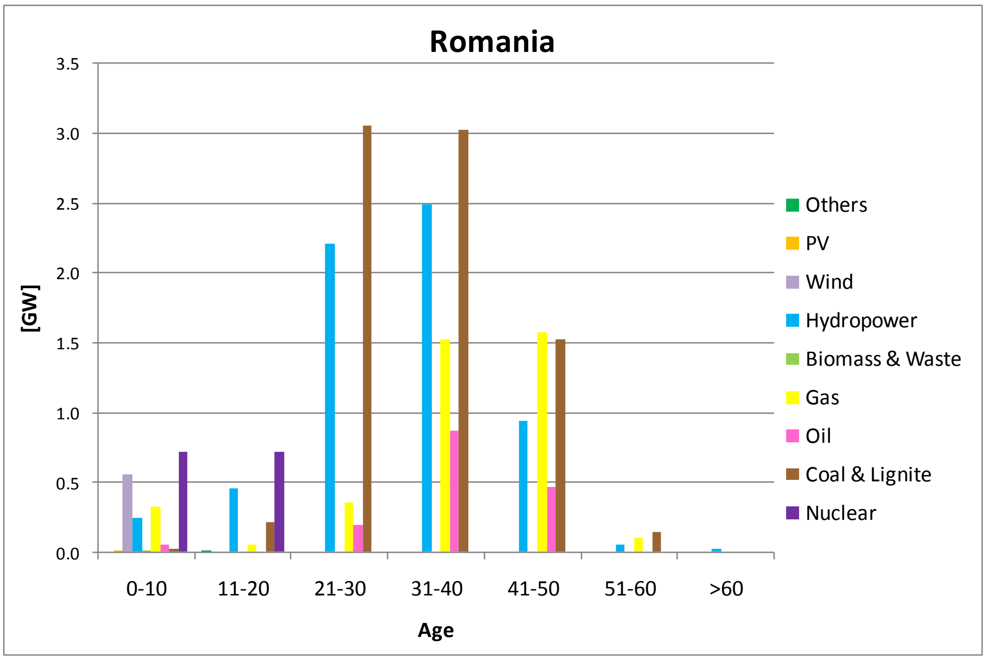


Figure 18: Age structure of existing power plants in Romania

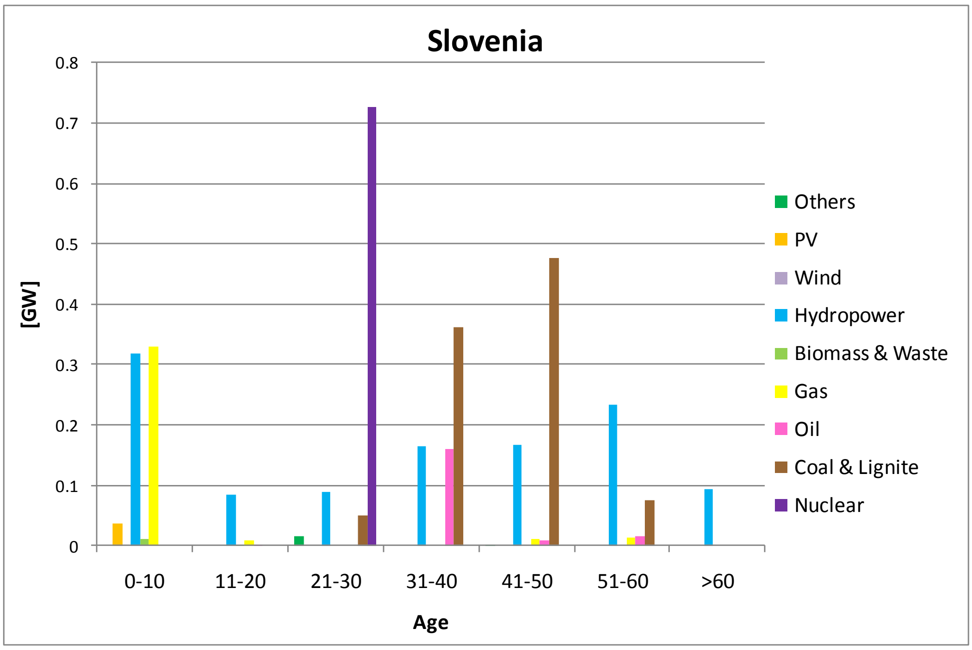


Figure 19: Age structure of existing power plants in Slovenia

The retirement plans for the five South East European countries resulting from the age structure of their power plant fleets are depicted in Figure 20.

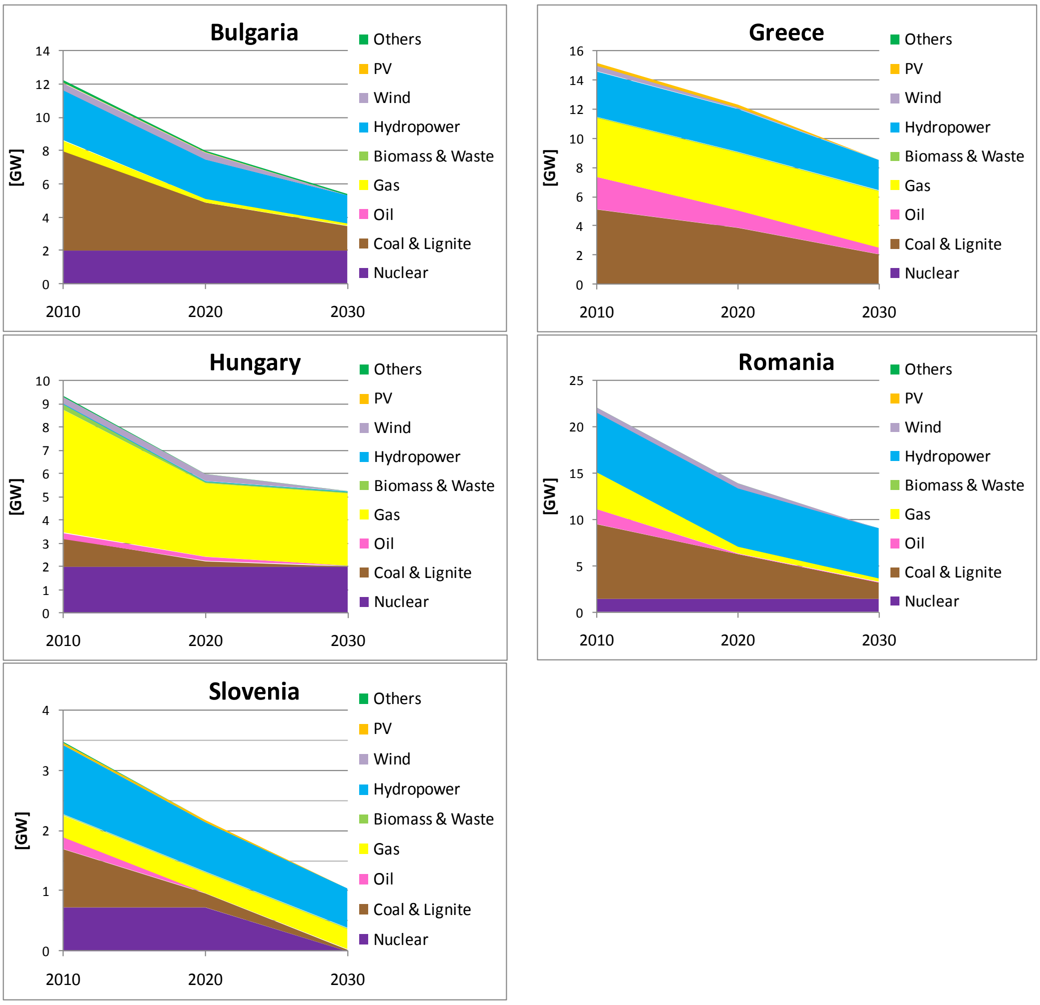


Figure 20: Capacity retirements in South East European countries

Except for Greece, all other South East European countries are subject to about 35% to 37% of retirements of their installed power plant capacities in the period from 2010 to 2020. Greece benefits from its younger power plants with a higher share of long-lived (cf. Table 7) coal power plants. Hungary, in contrast, also with a relatively young power plant fleet, has much higher capacity shares of more short-lived natural gas power plants. Of the countries considered, Romania has the highest installed capacity (22.1 GW) followed by Greece (15.1 GW) and Bulgaria (12.2 GW).

South East Europe	installed 2010 [MW]	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Bulgaria	12,216	4,225	35%
Greece	15,197	2,883	19%
Hungary	9,356	3,371	36%
Romania	22,091	8,140	37%
Slovenia	3,468	1,300	37%
Total	**62,328**	**19,918**	**32%**

Table 10: Capacity retirements in South East European countries

Hydropower plays a major role in all these countries except for Hungary, which is dominated by natural gas power plants. No retirements up to 2020 are expected for nuclear power plants (cf. Table 11), which are installed in all of these countries except Greece. Fossil fuel fired plants are most affected by retirements (cf. Table 11). About two-thirds of oil-fired power plant capacities (2.9 GW) and a little more than 40% of coal power plant capacities (9.2 GW) as well as of natural gas power plant capacities (5.9 GW) are expected to retire by 2020.

South East Europe	installed 2010 [MW]	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Nuclear	6,167	0	0%
Coal & Lignite	21,248	9,248	44%
Oil	4,266	2,853	67%
Gas	14,322	5,901	41%
Biomass & Waste	307	151	49%
Hydropower	13,832	1,320	10%
Wind	1,687	320	19%
Solar	277	0	0%
Others	222	125	56%
Total	**62,328**	**19,918**	**32%**

Table 11: Capacity retirements by fuel type in South East European countries

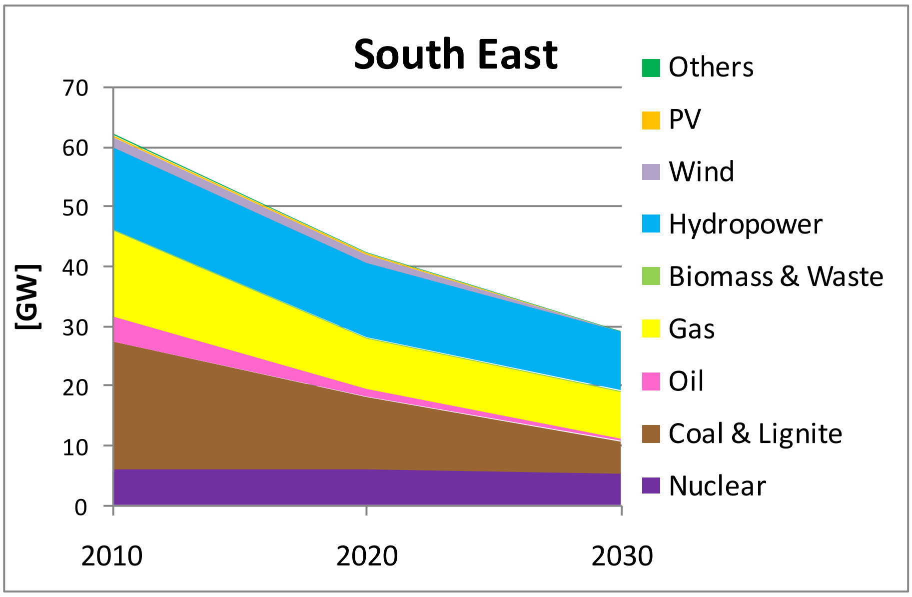


Figure 21: Capacity retirements in South East European countries

3.3.1.3 Mediterranean countries

The following two figures (Figure 22 and Figure 23) show the existing power plant capacities in the two Mediterranean countries, Italy and Spain. They are classified by fuel type and by age, stated in 10-year steps.

Compared to the previously investigated EU countries, both Italy and Spain are equipped with a relatively young power plant fleet. In both countries recently, i.e. during the last ten years, massive investments have been made in new natural gas-fired power plants. Almost no new coal power plants have been brought on line in Spain for at least twenty years and also no new nuclear power plants. In Italy there are no nuclear power plants.

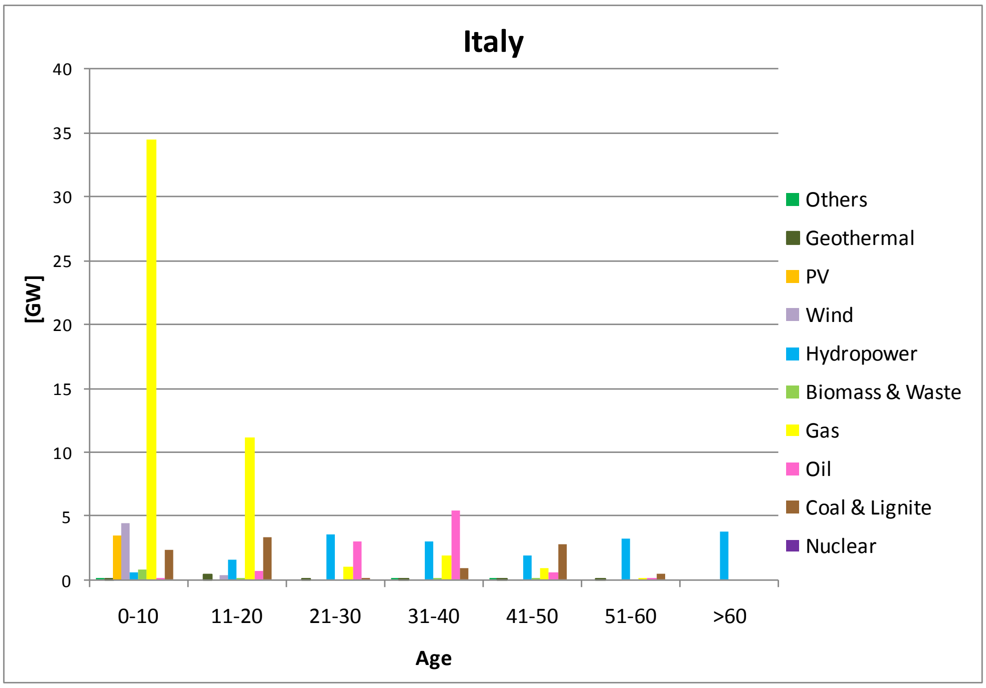


Figure 22: Age structure of existing power plants in Italy

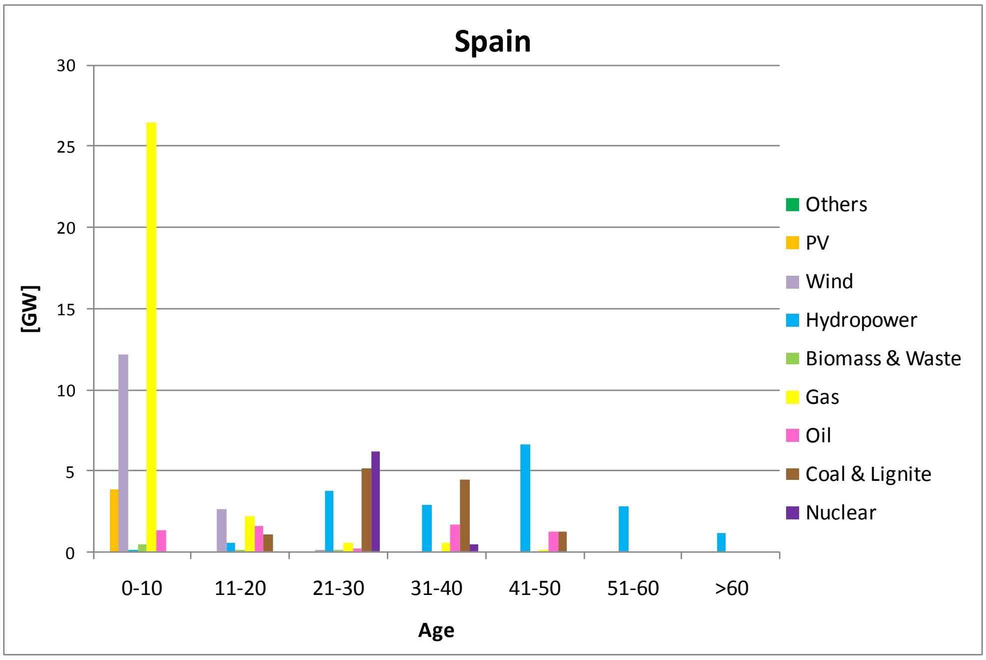


Figure 23: Age structure of existing power plants in Spain

The retirement plans for the two Mediterranean countries resulting from the age structure of their power plant fleets are depicted in Figure 24.

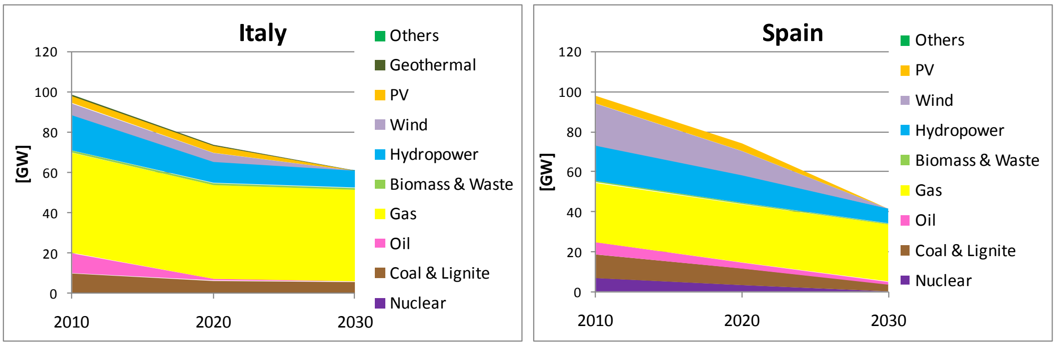


Figure 24: Capacity retirements in Mediterranean countries

Both countries have about the same total installed capacities of 98 GW (Table 12) and also their expected total capacity retirement by 2020 is almost the same at about 24 and 25 GW. The main difference between both countries is the role that natural gas power plants and wind power plants play in their power plant fleets. For Italy, natural gas power plants dominate, whereas for Spain a broader technology mix is installed with a considerable share of already installed wind power. Coal power plant capacities play a minor role in both countries and about one-third of capacities is forecast to retire in both countries together by 2020 (cf. Table 13).

retirement	installed 2010 MW	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Italy	98,587	24,757	25%
Spain	98,099	23,834	24%
Total	**196,686**	**48,591**	**25%**

Table 12: Capacity retirements in Mediterranean countries

It is interesting to note that oil-fired power plants are being retired at a high rate in both countries up to 2020, amounting to 92% of capacities installed in Italy and 51% of capacities installed in Spain. Since installed oil-fired power plant capacities are also at a rather high level, particularly in Italy, this power plant technology is also the one where most retirement in absolute figures is expected by 2020 for the Mediterranean countries, namely about 12.4 GW (cf. Table 13). Compared to renewable capacities for wind power and hydropower, which due to their short lifetimes also face high retirements of 10.2 GW (wind) and 11.1 GW (hydropower), expected retirements of conventional power plant capacities (other than of oil-fired power plants) is comparably lower in absolute figures: 7.2 GW of coal-fired power plants, 3.7 GW of natural gas fired power plants and 3.5 GW of nuclear power plants. In total 48.6 GW or 25% of capacity retirement is expected for the Mediterranean countries, as illustrated in Figure 25.

Mediterranean Europe	installed 2010 [MW]	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Nuclear	6,664	3,513	53%
Coal & Lignite	21,842	7,195	33%
Oil	16,128	12,389	77%
Gas	79,669	3,715	5%
Biomass & Waste	1,651	165	10%
Hydropower	35,714	11,082	31%
Wind	26,956	10,271	38%
Solar	7,287	0	0%
Geothermal	724	216	30%
Others	51	45	88%
Total	**196,686**	**48,591**	**25%**

Table 13: Capacity retirements by fuel type in Mediterranean countries

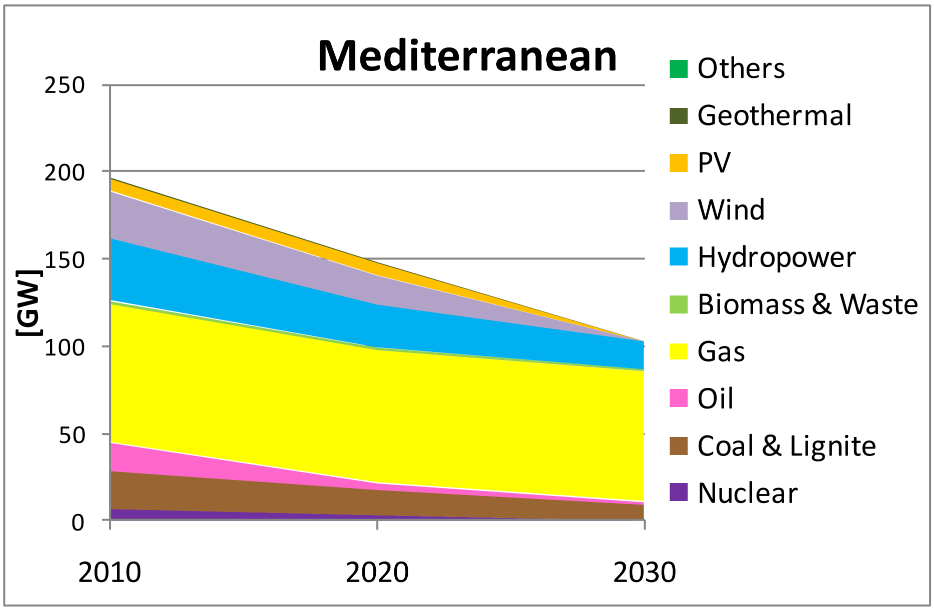


Figure 25: Capacity retirements in Mediterranean countries

3.3.1.4 Summary: Structure of existing power plants

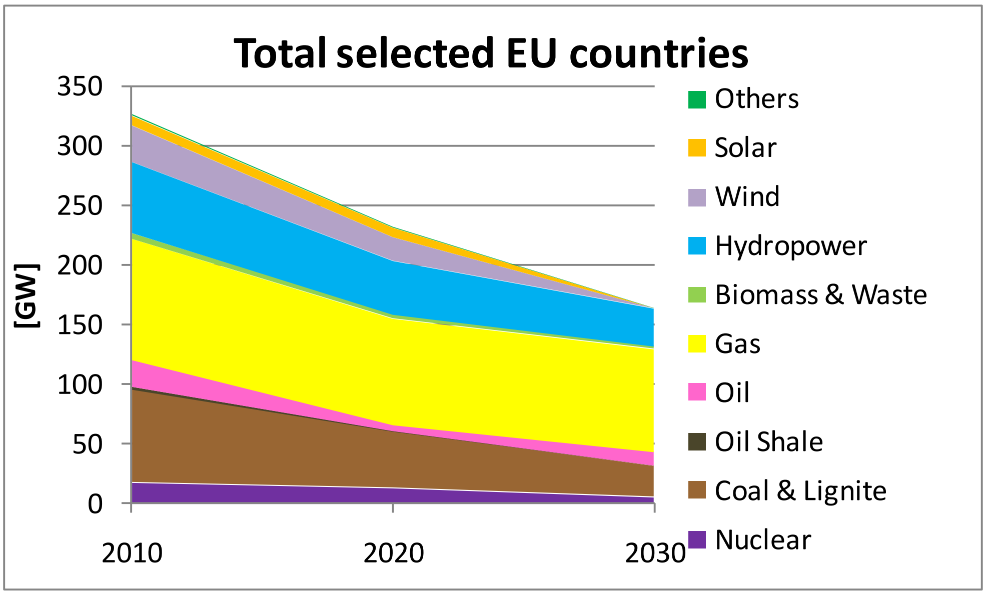


Figure 26: Capacity retirements in all selected EU countries

Figure 26 shows the expected retirement for all selected EU countries from 2010 up to 2020 and beyond. As can be seen from Table 14, the countries classified as North East European countries are exposed to the highest relative capacity retirement from 2010 to 2020, but in absolute terms capacity retirement in the only two Mediterranean countries, Italy and Spain, dominates with about 48.6 GW.

Capacities	installed 2010 MW	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
North East	67,294	25,740	38%
South East	62,328	19,918	32%
Mediterranean	196,686	48,591	25%
Total	**326,308**	**94,249**	**29%**

Table 14: Capacity retirements in all selected EU countries

However, as shown in Table 15, despite the highest total capacity retirement in the Mediterranean countries, expected retirements for coal-fired power plant capacities are higher for the South East European and particularly for the North East European countries. Almost the same holds for natural gas power plants. The Mediterranean countries dominate retirements particularly for oil-fired power plant capacities and for hydropower and wind power capacities. In total, 94.2 GW of power plant capacity is expected to be retired by 2020 in all selected EU countries.

Retirements 2010 - 2020	North East European [MW]	South East European [MW]	Mediterranean European [MW]	Total [MW]
Nuclear	1,010	0	3,513	**4,523**
Coal & Lignite	14,658	9,248	7,195	**31,101**
Oil Shale	1,770	0	0	**1,770**
Oil	2,013	2,853	12,389	**17,255**
Gas	2,898	5,901	3,715	**12,514**
Biomass & Waste	1,059	151	165	**1,375**
Hydropower	2,022	1,320	11,082	**14,424**
Wind	301	320	10,271	**10,892**
Solar	0	0	0	**0**
Others	9	125	261	**395**
Total	**25,740**	**19,918**	**48,591**	**94,249**

Table 15: Capacity retirements by fuel type for all selected EU countries

With regard to the installed capacities (see Table 16) it can be stated that, of the conventional power plants, particularly the capacities of oil-fired power plants (-76%), oil shale-fired power plants (-71%) and coal-fired power plants (-40%) will decrease by retirements. Natural gas power plant capacities however are only being retired by 12%. Also renewable power plant technologies face considerable ‘retirement rates’ of between 24% for hydropower and 36% for wind power, either due to old capacities (hydropower) or due to relatively short technical lifetimes (wind, biomass). Retirement of PV power plants is assumed to play no major role up to 2020 due to their shorter service life.

Capacities by fuel	installed 2010 [MW]	retirement 2010 - 2020 [MW]	retirement 2010 - 2020 %
Nuclear	**17,521**	**4,523**	26%
Coal & Lignite	**77,851**	**31,101**	40%
Oil Shale	**2,478**	**1,770**	71%
Oil	**22,698**	**17,255**	76%
Gas	**101,926**	**12,514**	12%
Biomass & Waste	**4,846**	**1,375**	28%
Hydropower	**59,547**	**14,424**	24%
Wind	**30,559**	**10,892**	36%
Solar	**7,849**	**0**	0%
Others	**1,033**	**395**	38%
Total	**326,308**	**94,249**	**29%**

Table 16: Capacity retirements by fuel type for all selected EU countries

3.3.2 Development of power plant capacities

The future development of power plant capacities comprises the replacement of retiring capacities but also further capacity net additions[3]. Two of the analysed data sources (cf. section 3.1) contain scenarios for future development of power plant capacities up to 2020 in the selected EU countries: [EU Trends] and [EURPROG], with [EU Trends] also providing figures for 2015. Both sources are presented and investigated in the following.

3.3.2.1 North East European countries

The following figures (Figure 27 to Figure 32) show the future development of power plant capacities up to 2020 in the North East European countries as outlined by [EU Trends] and by [EURPROG].

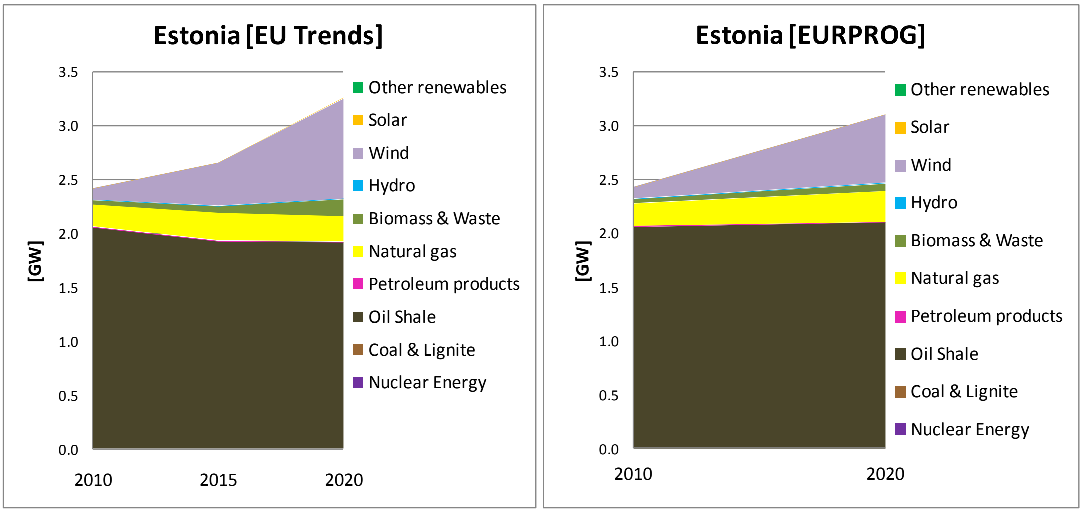


Figure 27: Capacity development in Estonia

[3] 'Capacity net additions' should not be confused with 'net electrical capacity'. The latter term is defined for each power plant as its gross electrical capacity less the electrical power required for the operation of the power plant itself. 'Net additions' of capacities however refer to gross additions of new power plant capacities less decommissioned power plant capacities. 'Capacity net additions' are therefore identical to the effective overall capacity increase or decrease.

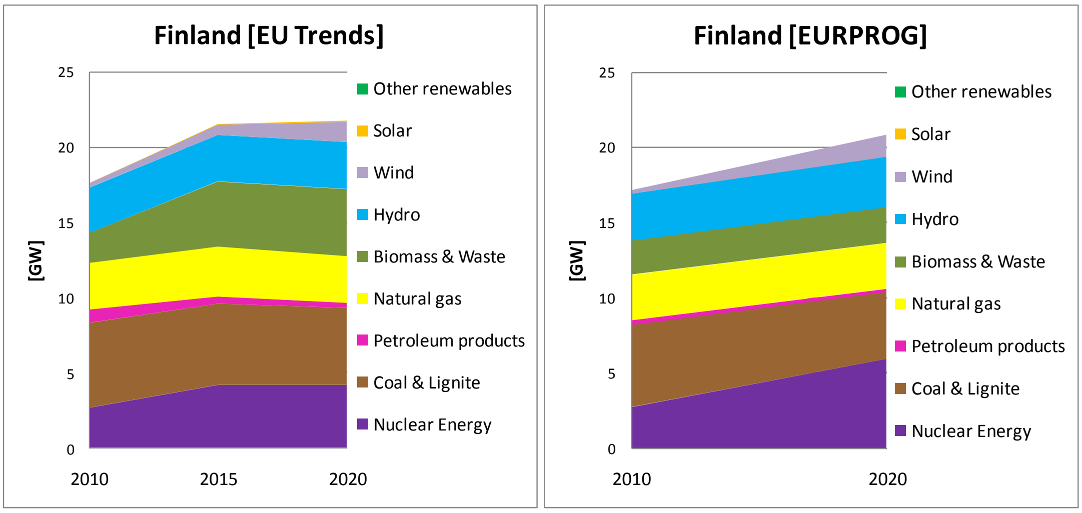


Figure 28: **Capacity development in Finland**

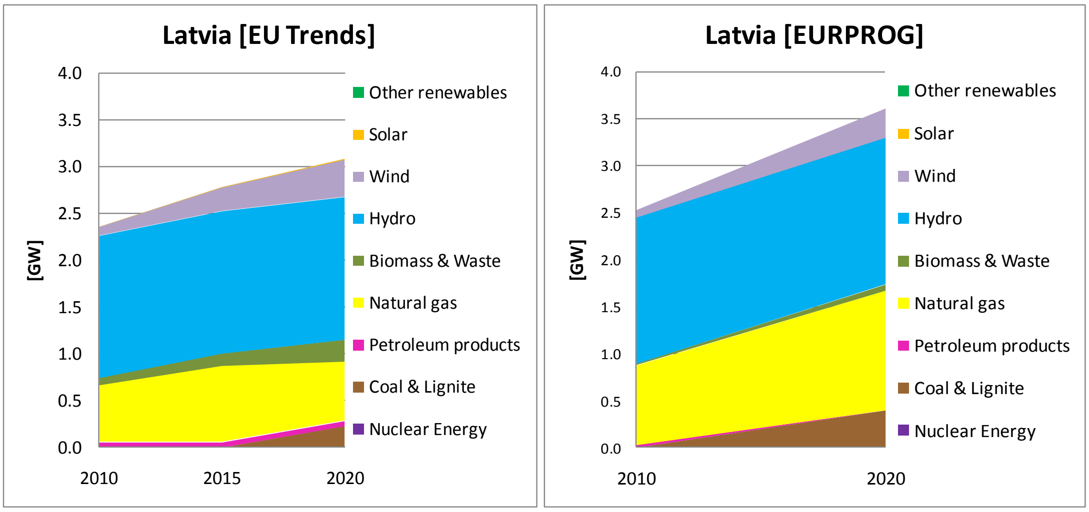


Figure 29: **Capacity development in Latvia**

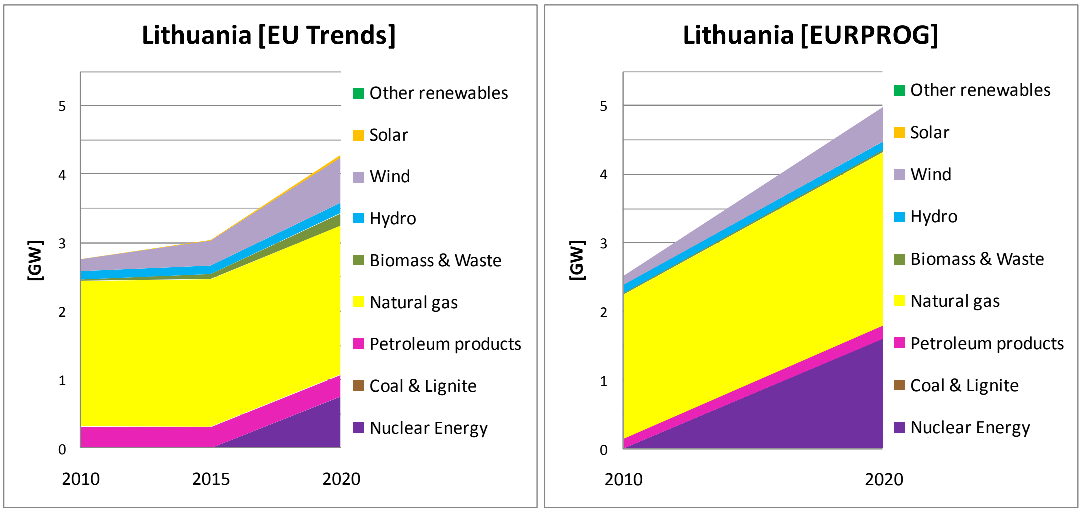
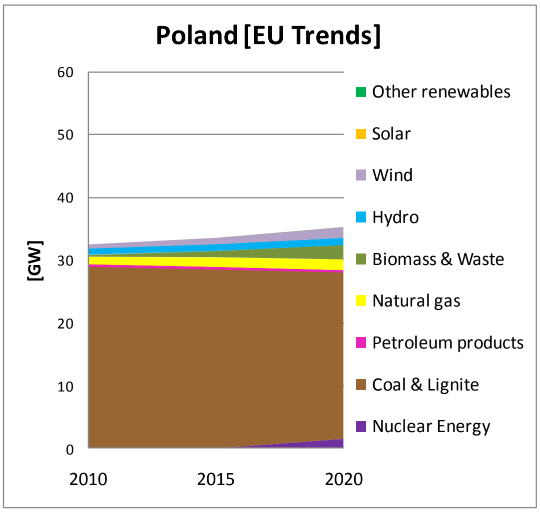


Figure 30: **Capacity development in Lithuania**



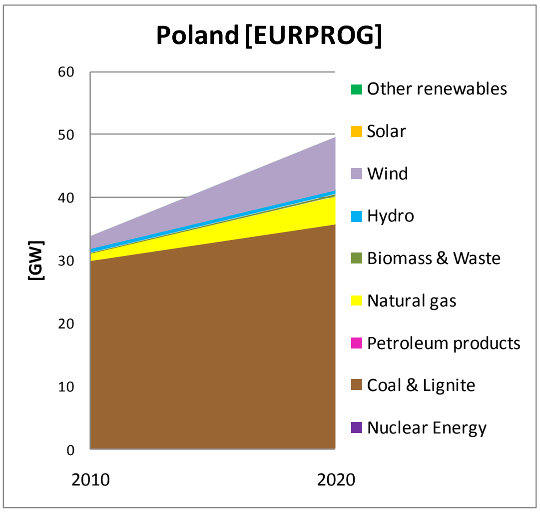
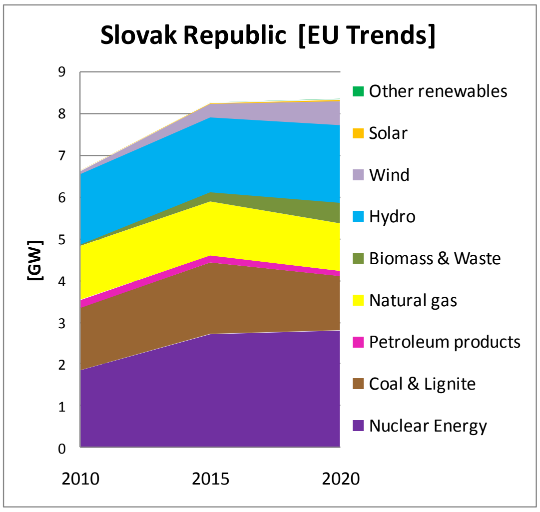


Figure 31: Capacity development in Poland



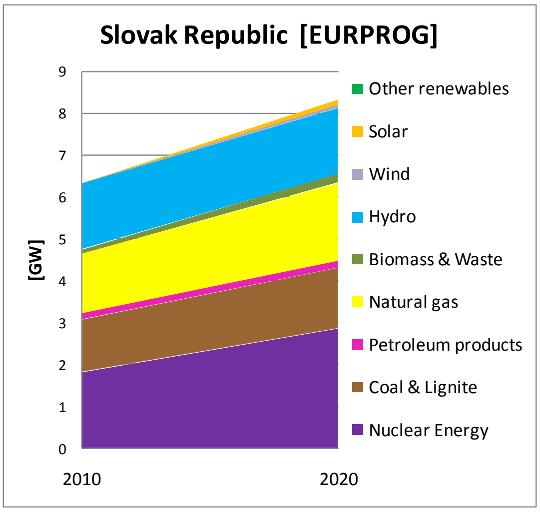


Figure 32: Capacity development in the Slovak Republic

As can be seen from Figure 27 to Figure 32, in general both publications, [EU Trends] and [EURPROG], do not differ too much regarding the expectations for electricity capacity developments, at least for most countries. This holds, of course, more particularly for the starting year 2010, where no large deviations are observed (cf. Table 17).

Differences between the two sources are particularly noted for the country with the highest power plant capacity of the North East European countries, Poland (cf. Figure 31). Whereas [EURPROG] assumes an increase by 47% from 33.9 GW to 49.7 GW by 2020 for Poland, with 5.9 GW assigned to coal-fired power plants alone, [EU Trends] assumes an increase by only 9%, from 32.5 GW to 35.3 GW (cf. Table 17). For coal power plants, [EU Trends] even expects a capacity drop of about 2.4 GW for Poland by 2020. This may result from the policy assumptions of [EU Trends] which include the constraints from the emission trading scheme and the national emission targets for each EU country. But also the development of wind power and natural gas power plants is seen more optimistically by [EURPROG]. On the other hand [EU Trends] foresees substantial market entries for biomass & waste and nuclear energy power plants in Poland.

Capacities by country	installed 2010 [EU Trends] [MW]	[EURPROG] [MW]	net additions until 2020 [EU Trends] [MW]	[EURPROG] [MW]	net additions until 2020 [EU Trends] [%]	[EURPROG] [%]
Estonia	2,423	2,429	834	675	34%	28%
Finland	17,582	17,137	4,157	3,742	24%	22%
Latvia	2,359	2,530	732	1,075	31%	42%
Lithuania	2,756	2,525	1,520	2,448	55%	97%
Poland	32,481	33,850	2,769	15,802	9%	47%
Slovak Republic	6,628	6,328	1,708	1,988	26%	31%
Total	**64,229**	**64,799**	**11,720**	**25,730**	**18%**	**40%**

Table 17: Capacity development in North East European countries

Since Poland has by far the largest power plant capacities of the North East European countries, the differences between [EU Trends] and [EURPROG] regarding capacity net additions in Poland are also reflected when totalling all North East European countries. The capacity development according to both data sources for North East European countries is shown in Figure 33. Differing expectations with regard to 2020 concern particularly coal-fired power plants, natural gas-fired power plants and wind power plants, for all of which [EURPROG] is much more optimistic regarding capacity net additions than [EU Trends]. For coal-fired power plant capacities, [EU Trends] even expects a capacity drop by about 3.1 GW (see Table 18), whereas [EURPROG] in contrast expects about 5.5 GW of net additions. On the other hand, [EU Trends] is more optimistic about power plant capacities fired with biomass and waste, and anticipates 5.3 GW capacity net additions by 2020 for these power plant types, whereas [EURPROG] only expects 0.5 GW net additions. Nevertheless, in total a gap of about 14 GW capacity net additions remains between the two scenarios, [EU Trends] and [EURPROG], when these are compared.

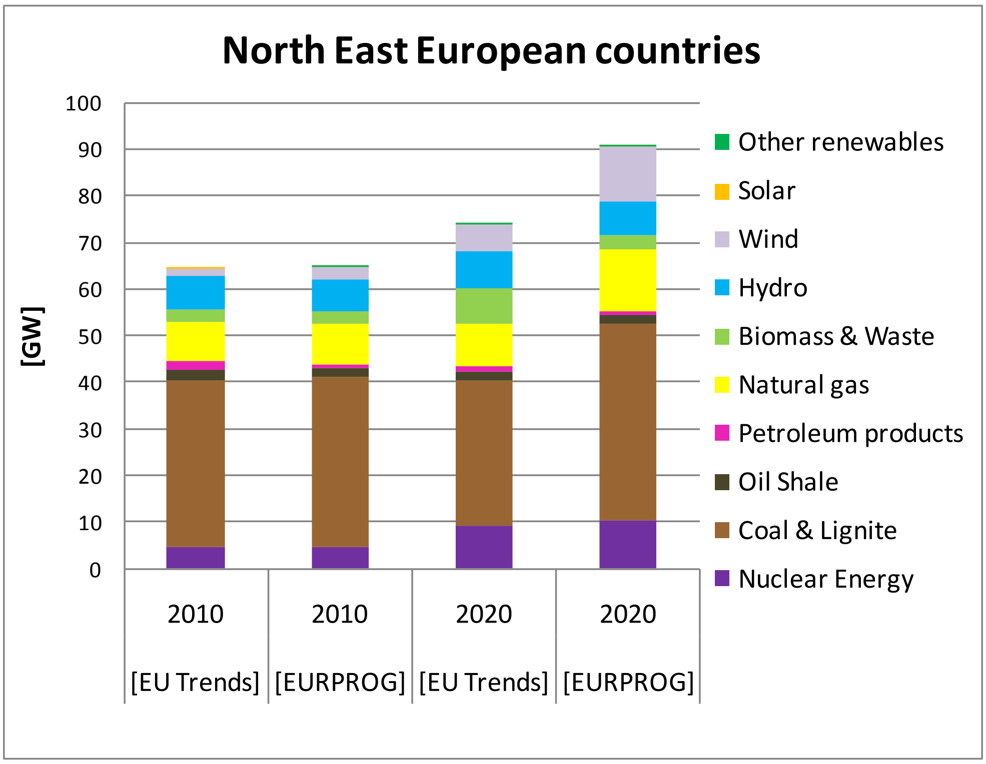


Figure 33: Capacity development by fuel type in North East European countries

Capacities by fuel	installed 2010 [EU Trends] [MW]	installed 2010 [EURPROG] [MW]	net additions until 2020 [EU Trends] [MW]	net additions until 2020 [EURPROG] [MW]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Nuclear Energy	4,550	4,510	4,738	5,853	104%	130%
Coal & Lignite	35,991	36,589	-2,918	5,466	-8%	15%
Oil Shale	2,056	2,056	-138	46	-7%	2%
Petroleum products	1,889	676	-665	-99	-35%	-15%
Natural gas	8,511	8,763	525	4,621	6%	53%
Biomass & Waste	2,465	2,565	5,280	485	214%	19%
Hydro	7,341	7,034	492	307	7%	4%
Wind	1,407	2,592	4,217	8,933	300%	345%
Solar	19	5	166	117	874%	2340%
Other renewables	0	9	23	1	n.a.	11%
Total	**64,229**	**64,799**	**11,720**	**25,730**	**18%**	**40%**

Table 18: Capacity development by fuel type in North East European countries

3.3.2.2 South East European countries

The following figures (Figure 34 to Figure 38) show the future development of power plant capacities up to 2020 in the South East European countries as outlined by [EU Trends] and by [EURPROG].

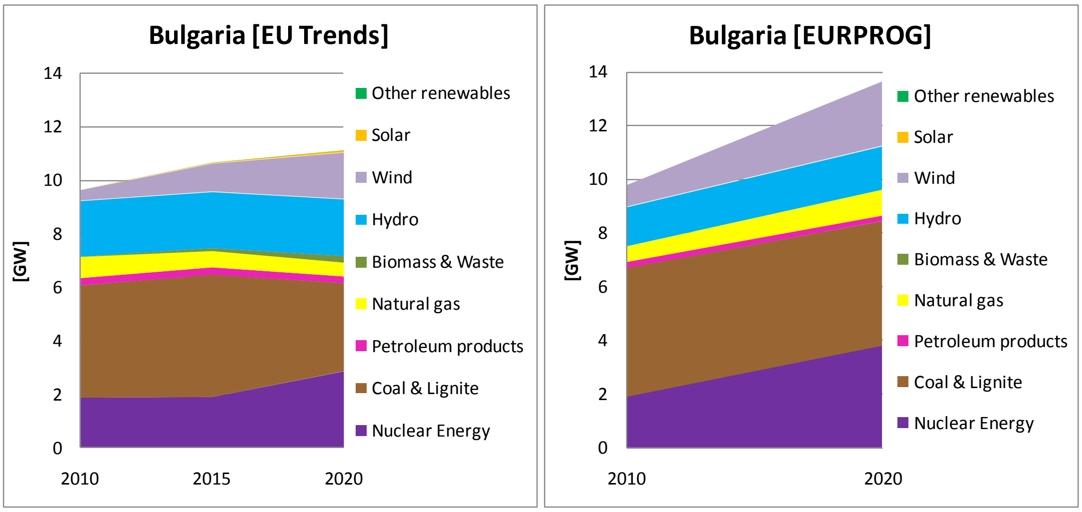


Figure 34: Capacity development in Bulgaria

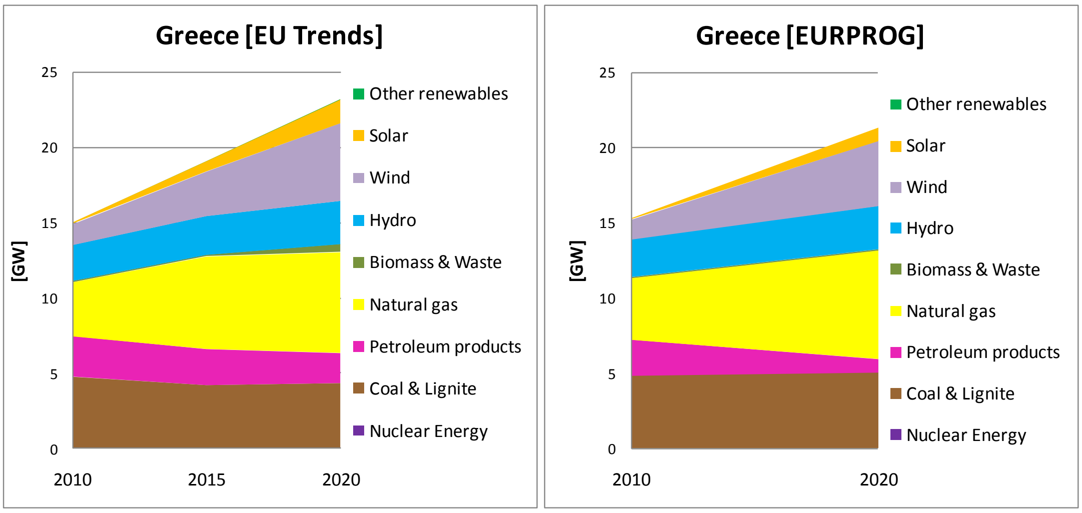


Figure 35: Capacity development in Greece

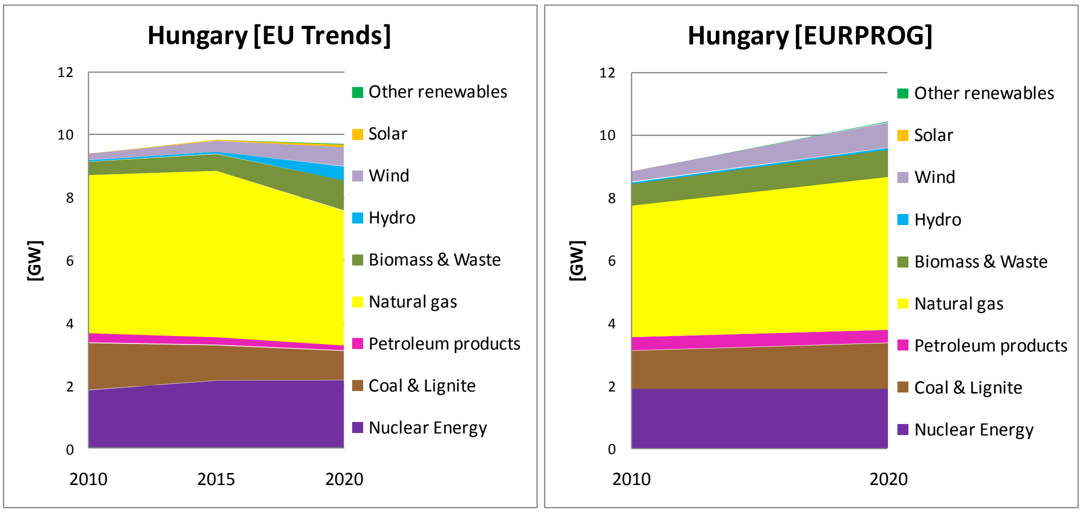


Figure 36: Capacity development in Hungary

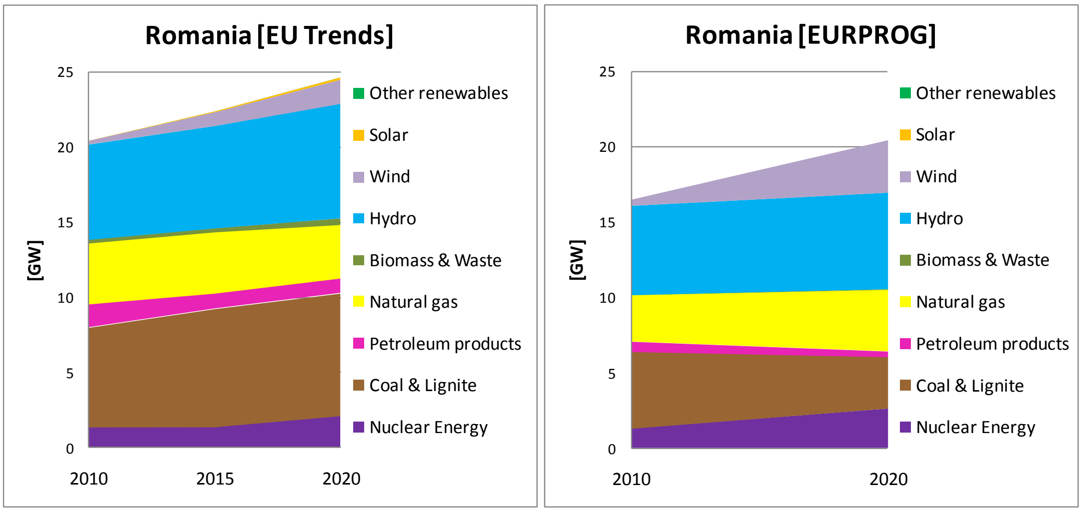


Figure 37: Capacity development in Romania

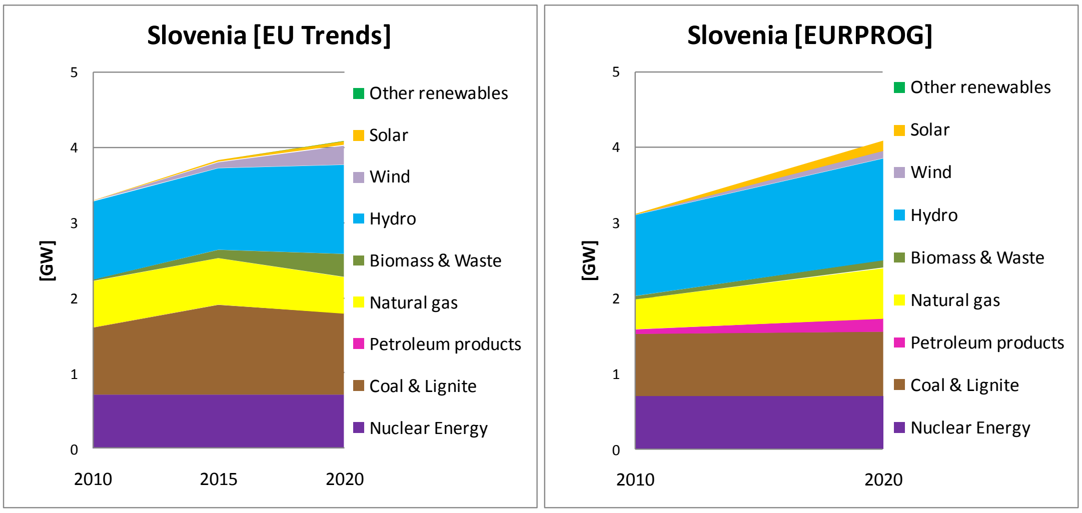


Figure 38: Capacity development in Slovenia

With regard to the two sources for capacity development, [EU Trends] and [EURPROG], the discrepancies for South East European countries are in general more apparent than for North East European countries.

For instance, power plant capacities in Romania are considered to be at a much higher level already in 2010 and in 2020 as well by [EU Trends] compared to the figures given by [EURPROG]. Using statistical data from [ENTSO-E] reveals that this may particularly result from an over-assessment of fossil fuel-fired power plant capacities by [EU Trends] in 2010: [ENTSO-E] counts 9,166 MW, [EURPROG] 8,843 MW and [EU Trends] 12,219 MW fossil fuel-fired power plant capacities.

For Bulgaria, Greece and Hungary, contracting capacities of coal-fired power plants are indicated by [EU Trends], which is for countries where [EURPROG] expects capacity extensions. But in general no systematic bias of any of the studies regarding coal-fired power plant capacity development can be identified for the South East European countries.

For natural gas power plants in Slovenia and Hungary, [EU Trends] predicts decreasing capacities in contrast to [EURPROG]. For Slovenia [EU Trends] indicates instead increases for wind power and biomass power plants that are much stronger than expected by [EURPROG]. As a common result, no study expects overall net capacity decreases for any of the South East European countries (cf. Table 19).

Capacities by country	installed 2010		net additions until 2020		net additions until 2020	
	[EU Trends] [MW]	[EURPROG] [MW]	[EU Trends] [MW]	[EURPROG] [MW]	[EU Trends] [%]	[EURPROG] [%]
Bulgaria	9,634	9,756	1,480	3,884	15%	40%
Greece	14,966	15,269	8,245	6,043	55%	40%
Hungary	9,386	8,825	308	1,588	3%	18%
Romania	20,397	16,460	4,230	3,966	21%	24%
Slovenia	3,285	3,113	793	979	24%	31%
Total	**57,668**	**53,423**	**15,056**	**16,460**	**26%**	**31%**

Table 19: Capacity development in South East European countries

Despite the large discrepancies between [EU Trends] and [EURPROG] regarding capacity development in the South East European countries, the differences level out somewhat in total over all South East European countries (see. Figure 39), and this even for each fuel type of the power plants (cf. Table 20).

Notably, net additions of natural gas-fired power plant capacities are perceived to be higher by [EURPROG] by 2020, but also net additions of wind power and nuclear power plant capacities. In contrast, [EU Trends] favours more biomass & waste, hydropower and solar power plant additions and sees less coal-fired power plant capacity reductions than [EURPROG] (cf. Table 20). Nevertheless for coal-fired power plant capacities, no positive net additions are perceived by either study.

Curiously, predicted overall net additions by [EU Trends] (15.1 GW) and by [EURPROG] (16.4 GW) differ less than the figures of both sources for the capacities already installed in 2010 (see Table 19).

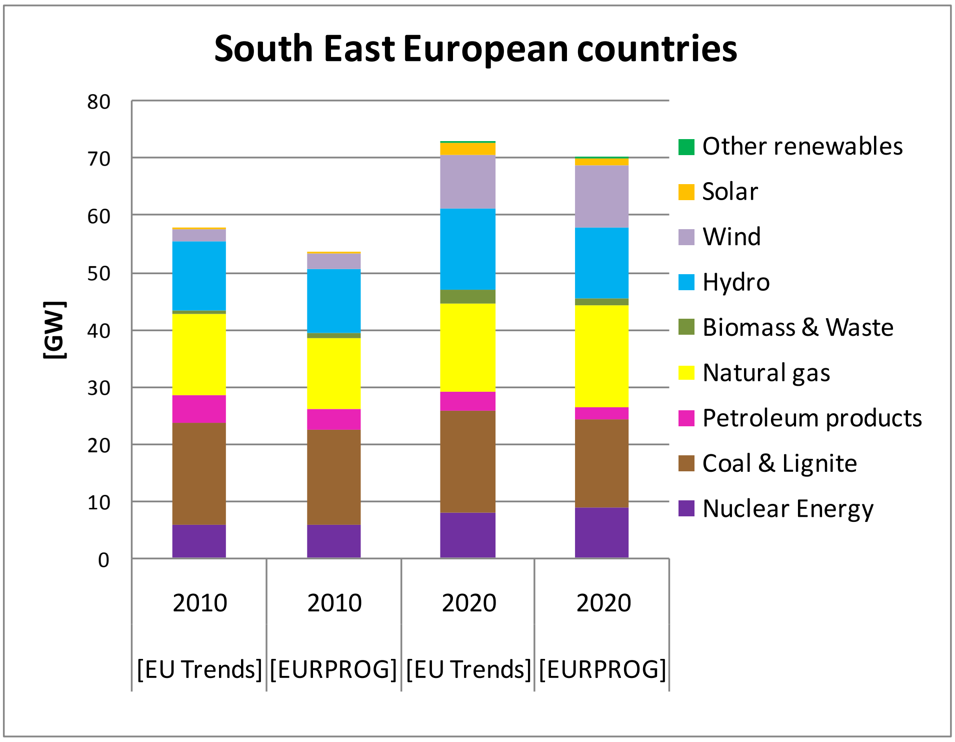


Figure 39: Capacity by fuel type in South East European countries

Capacities by fuel	installed 2010 [EU Trends] [MW]	installed 2010 [EURPROG] [MW]	net additions until 2020 [EU Trends] [MW]	net additions until 2020 [EURPROG] [MW]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Nuclear Energy	5,802	5,776	2,057	3,230	35%	56%
Coal & Lignite	18,023	16,740	-185	-1,353	-1%	-8%
Petroleum products	4,775	3,744	-1,422	-1,693	-30%	-45%
Natural gas	14,077	12,390	1,511	5,486	11%	44%
Biomass & Waste	800	828	1,685	268	211%	32%
Hydro	11,889	11,034	2,322	1,272	20%	12%
Wind	2,211	2,839	7,143	8,263	323%	291%
Solar	91	72	1,875	967	2060%	1343%
Other renewables	0	0	70	20	n.a.	n.a.
Total	**57,668**	**53,423**	**15,056**	**16,460**	**26%**	**31%**

Table 20: Capacity development by fuel type in South East European countries

3.3.2.3 Mediterranean countries

Figure 40 and Figure 41 show the future development of power plant capacities up to 2020 in the Mediterranean countries as outlined by [EU Trends] and by [EURPROG].

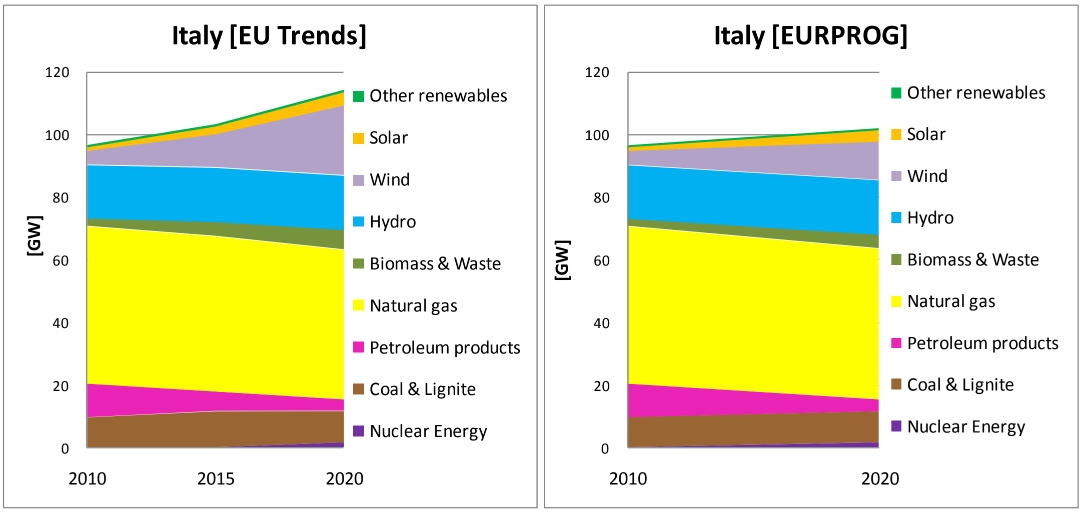


Figure 40: Capacity development in Italy

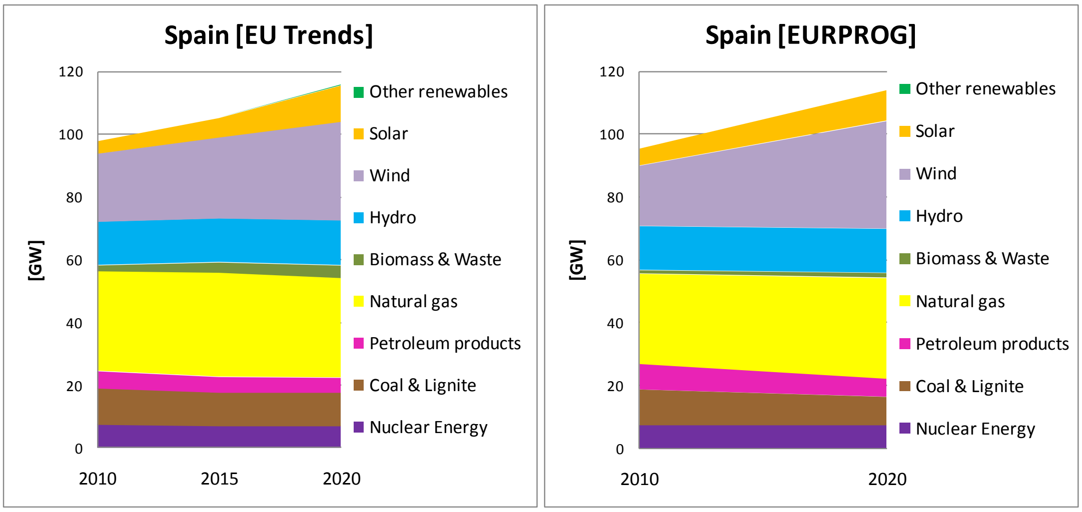


Figure 41: Capacity development in Spain

Installed capacities in the two countries classified as Mediterranean countries are the highest among all the selected EU countries. Both data sources hardly differ regarding the figures for installed capacities in 2010. However, for 2020 [EU Trends] expects about 12 GW more electrical capacities to be installed in Italy than [EURPROG] does, which is almost 12% higher (cf. Table 21). About 10 GW of this difference can be assigned to higher wind power additions and about 2 GW to higher biomass & waste power capacities. Characteristic for Italy is that the still existing considerable oil-fired power plant capacity is forecast by both scenarios to decrease by 2020 to almost one-third of its 2010 value. Coal and natural gas power plant capacities in Italy almost stagnate in both scenarios but approx. 1.6 GW nuclear power plant capacities are entering the Italian electricity market.

For Spain, higher capacities of natural gas power plants are indicated in [EU Trends] compared to [EURPROG] at the expense of capacities of power plants based on combustion of petroleum products, which are lower in [EU Trends] than listed in [EURPROG]. This may at least partly result from a different assignment of power plants to their primarily used fuel. Apart from this, particularly Spanish wind power and biomass & waste power plant capacities in 2010 are perceived to be higher and solar power capacities lower in [EU Trends] compared to [EURPROG].

Capacities by country	installed 2010 [EU Trends] [MW]	installed 2010 [EURPROG] [MW]	net additions until 2020 [EU Trends] [MW]	net additions until 2020 [EURPROG] [MW]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Italy	96,802	96,738	17,372	5,430	18%	6%
Spain	97,750	95,250	17,993	18,595	18%	20%
Total	**194,552**	**191,988**	**35,365**	**24,025**	**18%**	**13%**

Table 21: Capacity development in Mediterranean countries

Looking at both Mediterranean countries together (see Figure 42), it can be seen that [EU Trends] is generally much more optimistic regarding the future additions of renewable power plant capacities by 2020, particularly of biomass & waste, wind power and solar power plant capacities. Only for natural gas power plants, does [EU Trends] see in contrast to [EURPROG] no net positive capacity additions (cf. Table 22). And like for South East European countries, for Mediterranean countries, too, neither study indicates net positive additions for coal-fired power plants.

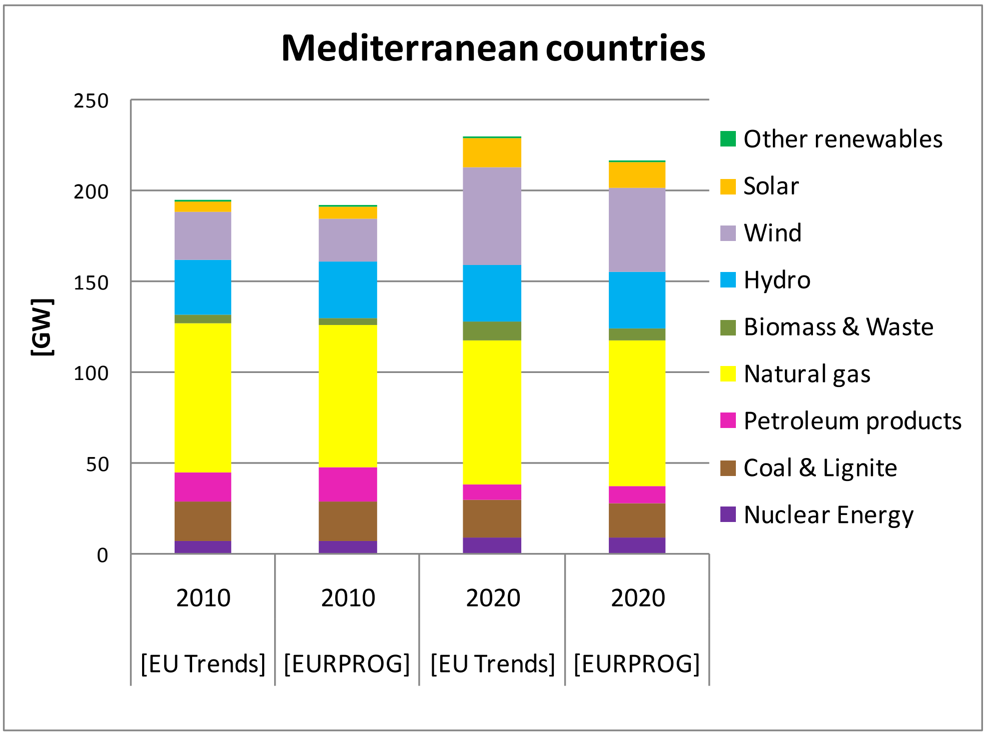


Figure 42: Capacity by fuel type in Mediterranean countries

Capacities by fuel	installed 2010 [EU Trends] [MW]	installed 2010 [EURPROG] [MW]	net additions until 2020 [EU Trends] [MW]	net additions until 2020 [EURPROG] [MW]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Nuclear Energy	7,434	7,419	1,131	1,579	15%	21%
Coal & Lignite	21,238	20,925	-460	-2,013	-2%	-10%
Petroleum products	16,155	18,878	-7,774	-9,234	-48%	-49%
Natural gas	82,276	79,155	-2,655	1,142	-3%	1%
Biomass & Waste	4,369	3,478	6,013	2,445	138%	70%
Hydro	30,914	31,122	817	410	3%	1%
Wind	26,181	23,755	27,480	22,799	105%	96%
Solar	5,250	6,585	10,519	6,897	200%	105%
Other renewables	735	671	294	0	40%	0%
Total	**194,552**	**191,988**	**35,365**	**24,025**	**18%**	**13%**

Table 22: Capacity development by fuel type in Mediterranean countries

3.3.2.4 Summary: Development of power plant capacities

Figure 43 shows the future development of power plant capacities summed for all selected EU countries up to 2020, as outlined by [EU Trends] and [EURPROG]. Despite having seen - by source - quite different results for the country clusters considered, in total the differences level out, at least for total capacity net additions. For individual countries, main outstanding differences between the two data sources are identified for Poland and Italy.

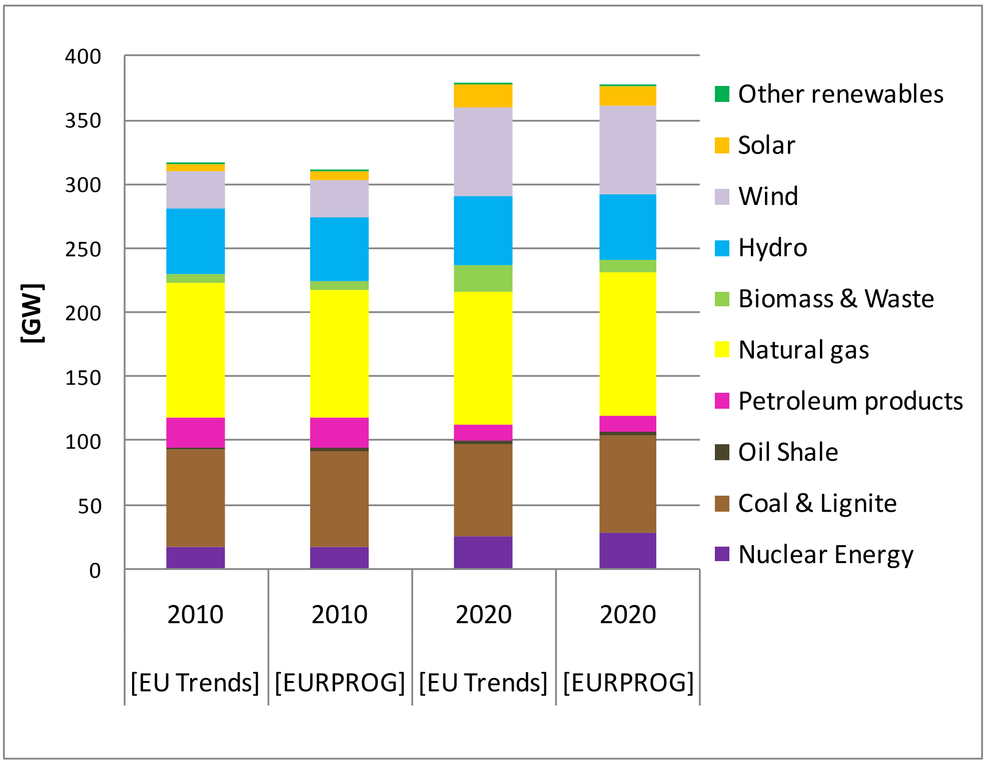


Figure 43: Capacity by fuel type in all selected European countries

For all countries in any scenario, positive capacity net additions are foreseen. The highest capacity growth is expected in the North East and South East European countries, but the highest capacity net additions in absolute terms can be expected for the two Mediterranean countries in a range from about 24 to 35 GW (see Table 23). In total, between 62.1 GW and 66.2 GW of capacity net additions are expected, a relative increase of around 20% to 21%.

Capacities	installed 2010		net additions until 2020		net additions until 2020	
	[EU Trends] [MW]	[EURPROG] [MW]	[EU Trends] [MW]	[EURPROG] [MW]	[EU Trends] [%]	[EURPROG] [%]
North East	64,229	64,799	11,720	25,730	18%	40%
South East	57,668	53,423	15,056	16,460	26%	31%
Mediterranean	194,552	191,988	35,365	24,025	18%	13%
Total	**316,449**	**310,210**	**62,141**	**66,215**	**20%**	**21%**

Table 23: Capacity development in all selected European countries

More than half of these net additions consist of additional wind power plants (cf. Table 24), and also the other renewable technologies are among the power plant types with the highest growth rates. However, the assumptions in the two data sources regarding the composition of the total power plant capacities in 2020 differ quite a lot (cf. Table 24). [EU Trends] expects much more renewable shares, particularly from biomass & waste power plants and from solar power plants. On the other hand [EURPROG] generally expects more conventional power plant additions, particularly more natural gas power plants (+11.2 GW). Higher expectations by [EURPROG] regarding coal power plants result mainly from the high value of about 5.9 GW coal power plant capacity net additions in Poland. But except for this, the trend for installed coal power plant capacities is generally seen by both scenarios to slightly decrease by 2020. The only power plant type with strongly shrinking capacities is the one fuelled by petroleum products.

Capacities by fuel	installed 2010		net additions until 2020		net additions until 2020	
	[EU Trends] [MW]	[EURPROG] [MW]	[EU Trends] [MW]	[EURPROG] [MW]	[EU Trends] [%]	[EURPROG] [%]
Nuclear Energy	17,786	17,705	7,926	10,662	45%	60%
Coal & Lignite	75,252	74,254	-3,563	2,100	-5%	3%
Oil Shale	2,056	2,056	-138	46	-7%	2%
Petroleum products	22,819	23,298	-9,861	-11,026	-43%	-47%
Natural gas	104,864	100,308	-619	11,249	-1%	11%
Biomass & Waste	7,634	6,871	12,978	3,198	170%	47%
Hydro	50,144	49,190	3,631	1,989	7%	4%
Wind	29,799	29,186	38,840	39,995	130%	137%
Solar	5,360	6,662	12,560	7,981	234%	120%
Other renewables	735	680	387	21	53%	3%
Total	**316,449**	**310,210**	**62,141**	**66,215**	**20%**	**21%**

Table 24: Capacity development by fuel type in all selected European countries

The quite different results from country to country but also in total, as obtained from both data sources, [EU Trends] and [EURPROG], cannot be explained. The reason is that neither the scenario methods nor the basis of expert judgement impacting the results of the two studies are sufficiently transparent. This holds particularly for [EURPROG], for which the scenario may be obtained with different approaches and assumptions from the EURELECTRIC members in the various countries. [EU Trends] refers to a scenario framework that explicitly includes the latest climate policy measures on EU level but also the mandatory national greenhouse gas emission and energy targets set for 2020. So, to include the impact of these policies on the anticipated power plant investment behaviour in the proximity of the EU boundaries, the [EU Trends] scenario is taken as a reference for this study.

3.3.3 Development of electricity generation

Like for the future development of power plant capacities, the two data sources [EU Trends] and [EURPROG] also provide scenarios for future development of electricity generation up to 2020 for all selected EU countries. Again the results for the two sources are presented and compared in the following. And for both, the outlined electricity generation path in each country is also contrasted with its expected electricity demand in order to identify electricity import needs or export potentials for each country. The analysis is again performed along the three suggested country clusters of the selected EU countries.

3.3.3.1 North East European countries

The following figures (Figure 44 to Figure 49) show the future development of electricity generation by fuel type up to 2020 in the North East European countries as outlined by [EU Trends] and by [EURPROG].

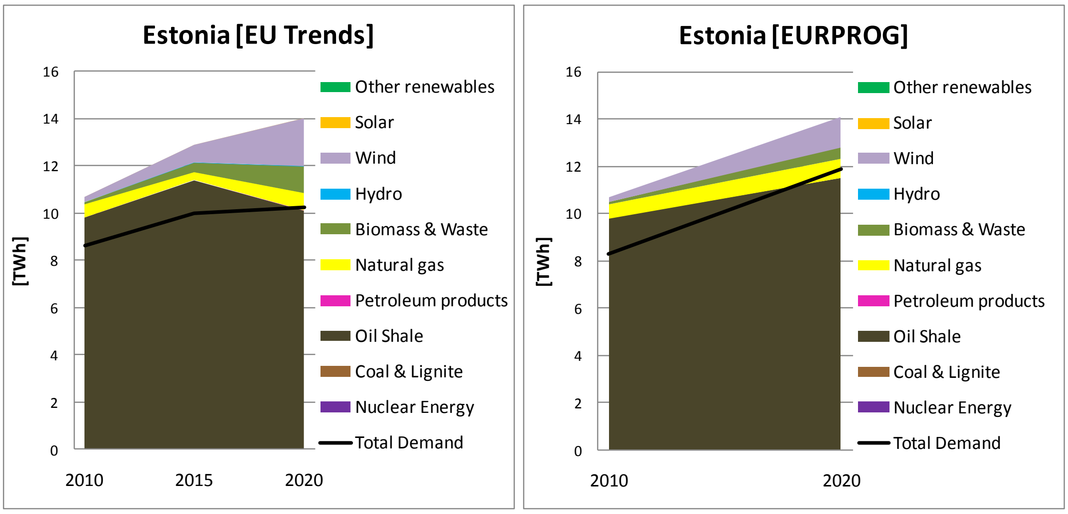


Figure 44: Electricity generation development in Estonia

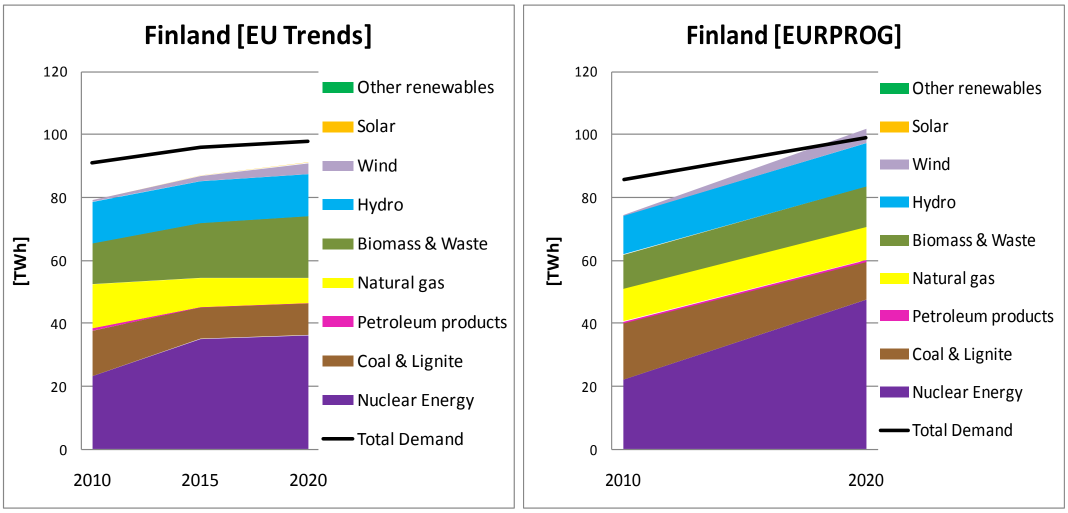


Figure 45: Electricity generation development in Finland

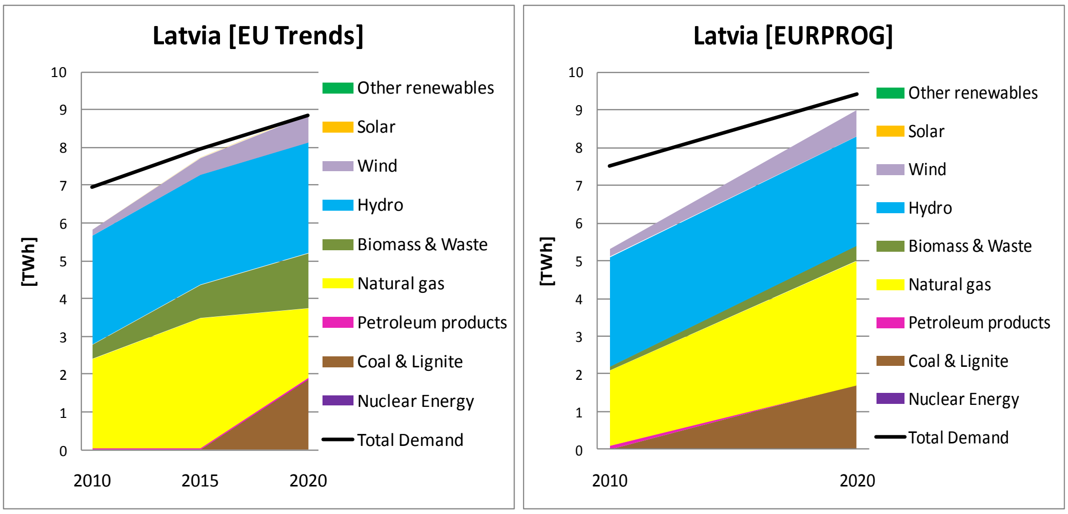


Figure 46: Electricity generation development in Latvia

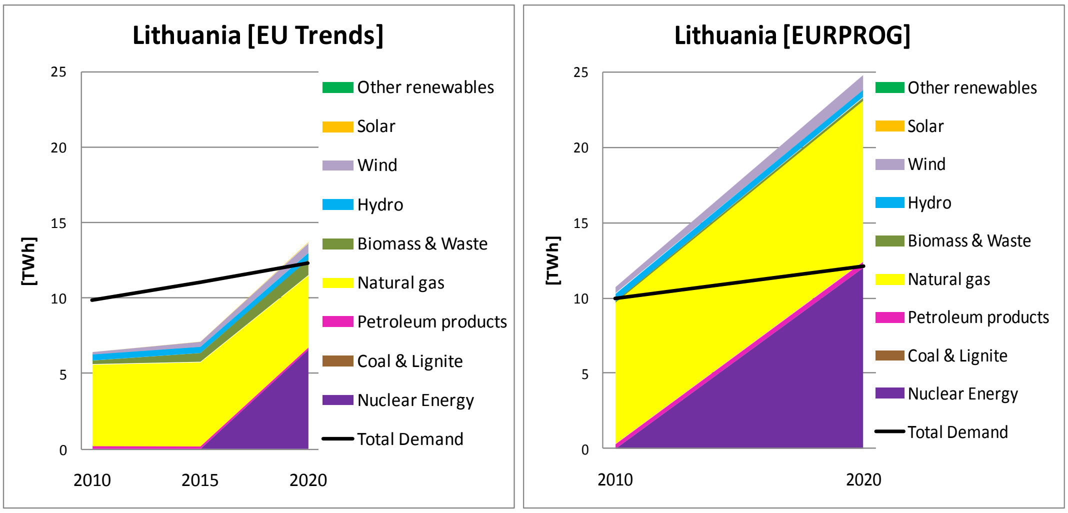


Figure 47: Electricity generation development in Lithuania

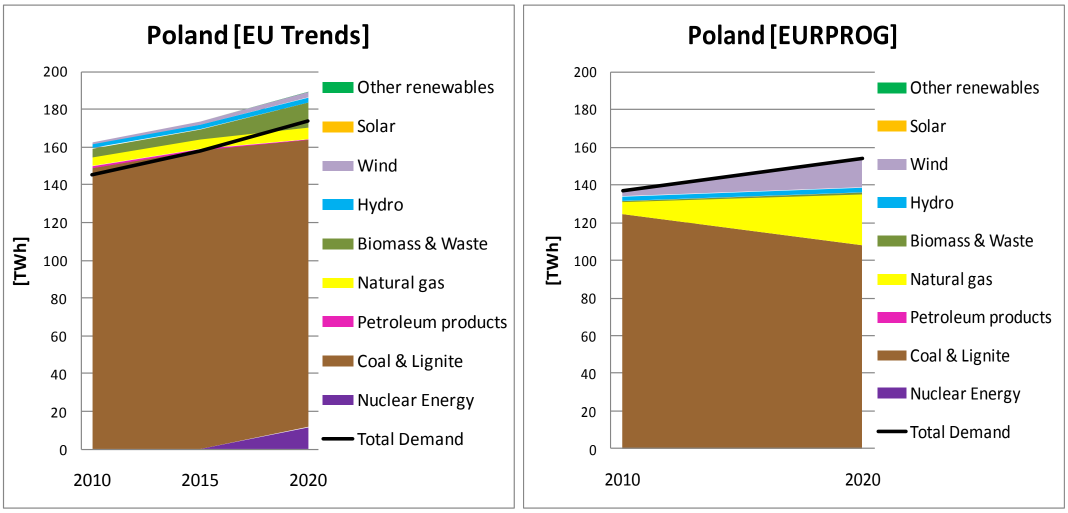


Figure 48: **Electricity generation development in Poland**

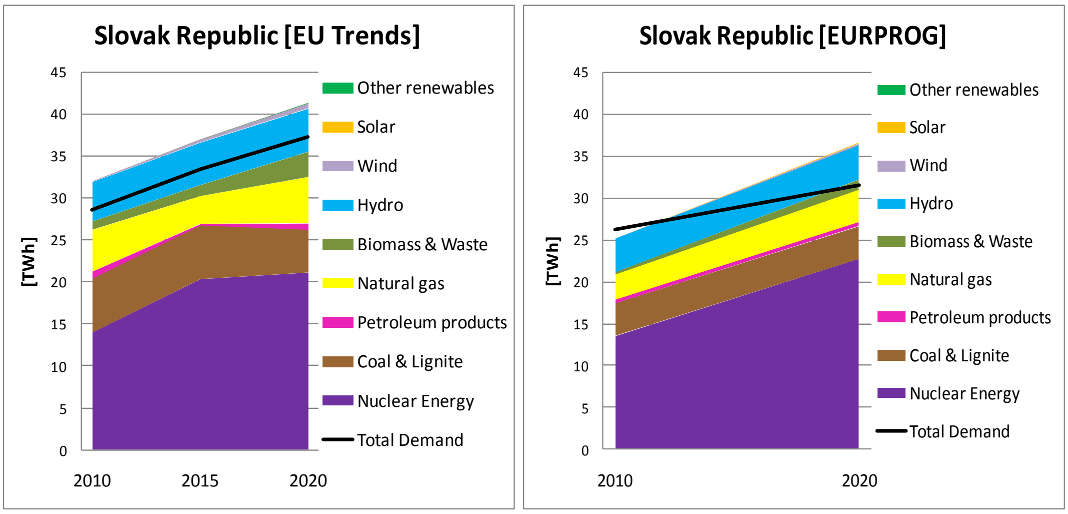


Figure 49: **Electricity generation development in the Slovak Republic**

The figures demonstrate that, among all countries considered, more or less substantial differences between the figures as given by the two data sources can be found. Even for countries where total electricity generation figures almost coincide, the composition of electricity generation by fuel type can be quite different. The greatest deviations between the two scenarios, [EU Trends] and [EURPROG], are found for Lithuania and for Poland.

For Poland's development of electricity generation from coal, [EU Trends] forecasts increases and [EURPROG] decreases. This is unexpected, since it is just the reverse of the development of coal-fired power plant capacities that is expected in the two studies. [EU Trends] predicts a slightly decrease of Polish coal-fired power plant capacities up to 2020 and [EURPROG] foresees a strong increase (cf. Figure 31, section 3.3.2.1).

And for Poland even the electricity generation values for 2010 already differ by more than 10% between the two data sources. The same is observed for Lithuania and the Slovak Republic. So in Figure 50, the 2010 electricity generation figures of all North East European countries are compared with those of [Eurostat] to show up the different assumptions for electricity amounts in 2010 by fuel type. Since [Eurostat] subsumes all electricity generated from ‘combustible fuels’ within a single classification, this is illustrated in Figure 50 by striped blocks within the bar charts for [Eurostat].

It turns out that the 2010 generation values for Latvia and Lithuania are better met by [EU Trends] whereas the 2010 values for Poland and Slovak Republic are better matched by [EURPROG]. The same result is also confirmed when total generated electricity values for 2010 by [EU Trends] and [EURPROG] are compared with statistical values for electricity generation published by [ENTSO-E].

As a result, we can assume that Poland and the Slovak Republic are probably not that important as electricity net exporting countries in 2010 as indicated by [EU Trends] but Lithuania is indeed a large electricity importer in 2010, as indicated by [EU Trends].

With regard to 2020, for some countries differences may arise because [EURPROG] seems to expect earlier commissioning of planned new nuclear power plants than [EU Trends] does.

From the presented development of electricity demand figures, it can be seen that, for all countries, the total electricity generation increase up to 2020 is stronger than the electricity demand increase (cf. Figure 44 to Figure 49). As a result, Lithuania, Slovak Republic and - according to [EURPROG] - also Finland are going to become net electricity exporting countries by 2020, Estonia already is, and Latvia is well on the way to becoming one later.

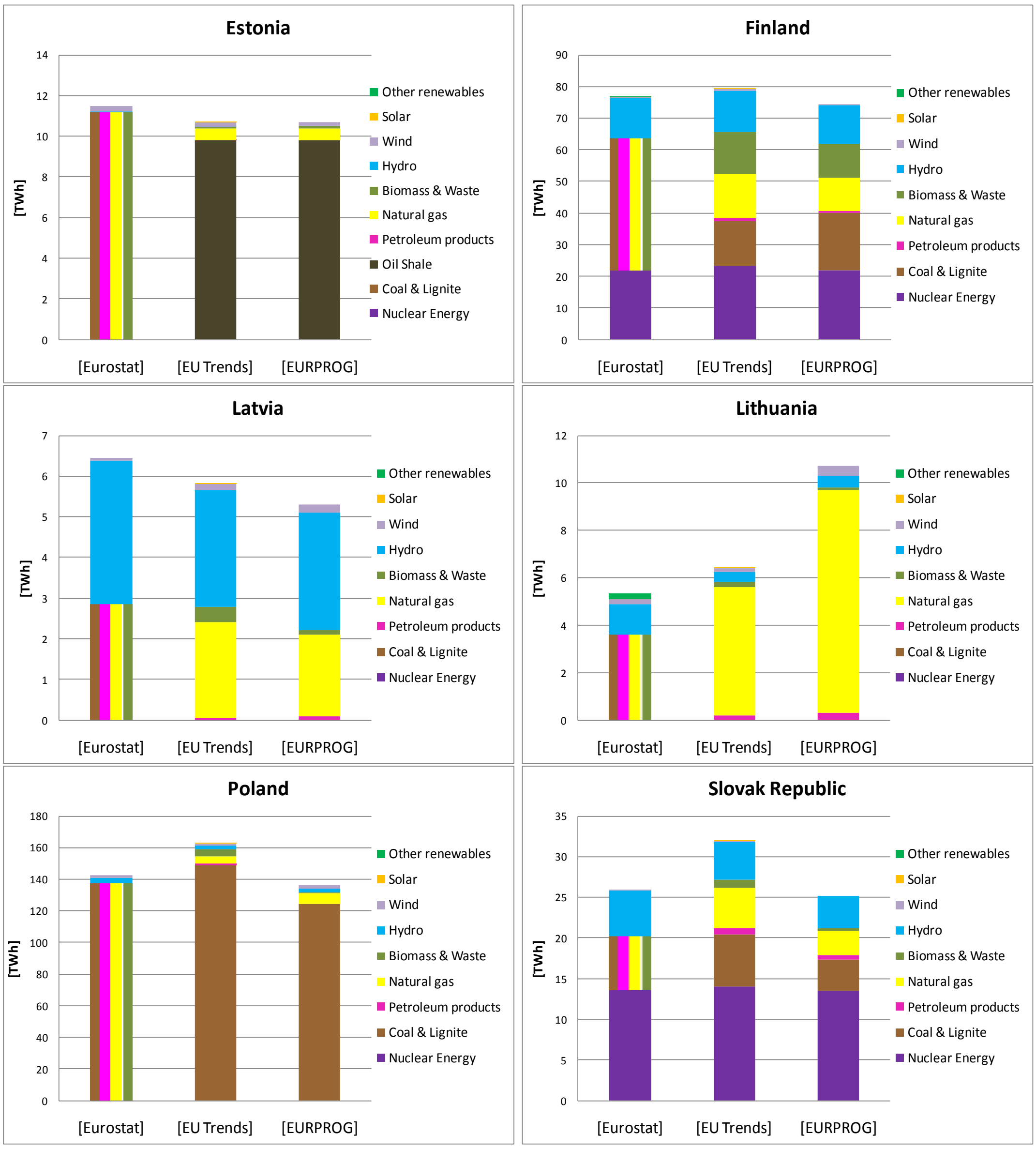


Figure 50: Electricity generation 2010 in North East European countries

In both scenarios, Lithuania is forecast to more than double its electricity generation from 2010 to 2020 (cf. Table 25). The largest absolute electricity generation increments are found either for Finland or for Poland, depending on the scenario referred to. In total, between 61.5 GW (+21%) and 77.4 GW (+29%) more electricity generation is expected in the North East European countries.

Generation by country	2010 [EU Trends] [GWh]	2010 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [GWh]	net additions until 2020 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Estonia	10,697	10,700	3,298	3,400	31%	32%
Finland	79,216	74,500	11,827	27,400	15%	37%
Latvia	5,820	5,300	3,066	3,700	53%	70%
Lithuania	6,416	10,700	7,266	14,100	113%	132%
Poland	162,542	136,100	26,606	17,400	16%	13%
Slovak Republic	31,941	25,200	9,395	11,400	29%	45%
Total	**296,632**	**262,500**	**61,458**	**77,400**	**21%**	**29%**

Table 25: Electricity generation development in North East European countries

By fuel type, largest electricity increases in the North East European countries will come from nuclear energy and, depending on which scenario to believe, either from biomass & waste power plants [EU Trends] or from wind power and natural gas [EURPROG] (see Table 26). For natural gas, though, [EU Trends] indicates decreasing electricity generation, and for coal-based electricity both studies expect declines, [EURPROG] even by 20.8 TWh (-14%).

Thanks to its higher generation growth rates compared to demand growth rates, the whole region of the North East European countries is on its way to becoming a net electricity exporter by 2020, according to [EURPROG] (see Figure 51). According to [EU Trends] it already is an electricity exporting region and will increase its electricity exports up to 2020.

Generation by fuel	2010 [EU Trends] [GWh]	2010 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [GWh]	net additions until 2020 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Nuclear Energy	37,244	35,500	38,418	46,600	103%	131%
Coal & Lignite	169,464	146,300	-338	-20,800	0%	-14%
Oil Shale	9,824	9,800	290	1,700	3%	17%
Petroleum products	2,982	1,400	-1,621	100	-54%	7%
Natural gas	32,198	32,300	-5,147	24,200	-16%	75%
Biomass & Waste	19,292	11,800	20,304	4,400	105%	37%
Hydro	23,471	22,000	1,010	1,800	4%	8%
Wind	2,141	3,400	8,179	19,200	382%	565%
Solar	16	0	166	100	1038%	n.a.
Other renewables	0	0	197	100	n.a.	n.a.
Total	**296,632**	**262,500**	**61,458**	**77,400**	**21%**	**29%**

Table 26: Electricity generation development by fuel type in North East European countries

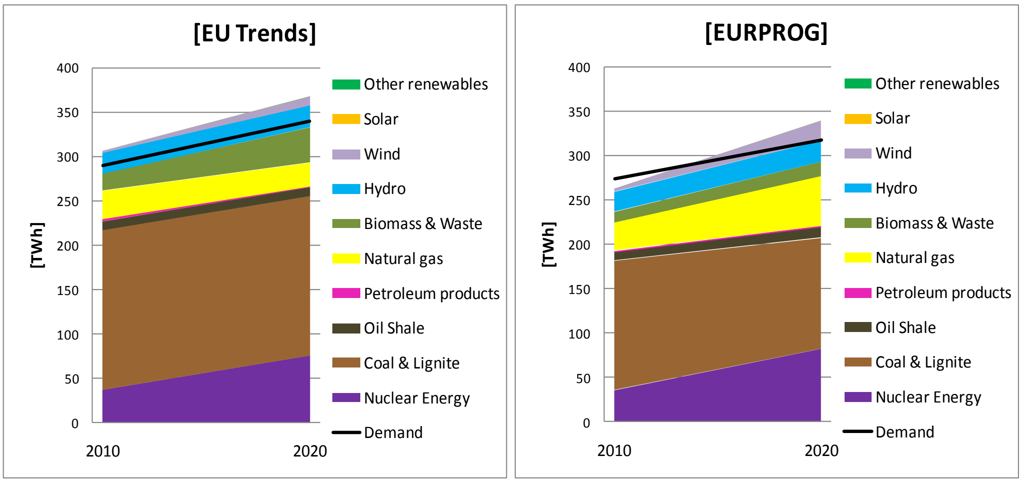


Figure 51: Electricity generation development in North East European countries

3.3.3.2 South East European countries

The following figures (Figure 52 to Figure 56) show the future development of electricity generation by fuel type up to 2020 in the South East European countries as outlined by [EU Trends] and by [EURPROG].

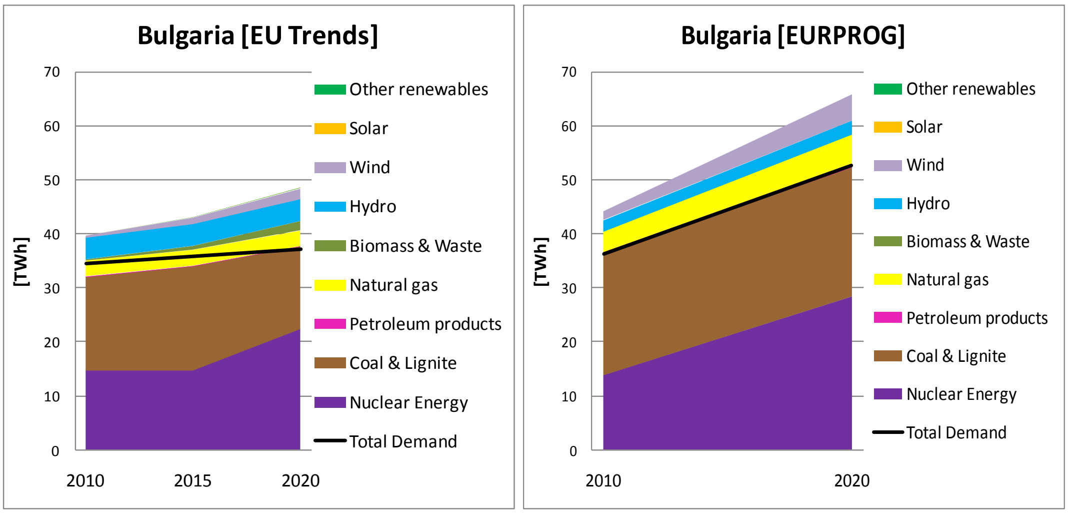


Figure 52: Electricity generation development in Bulgaria

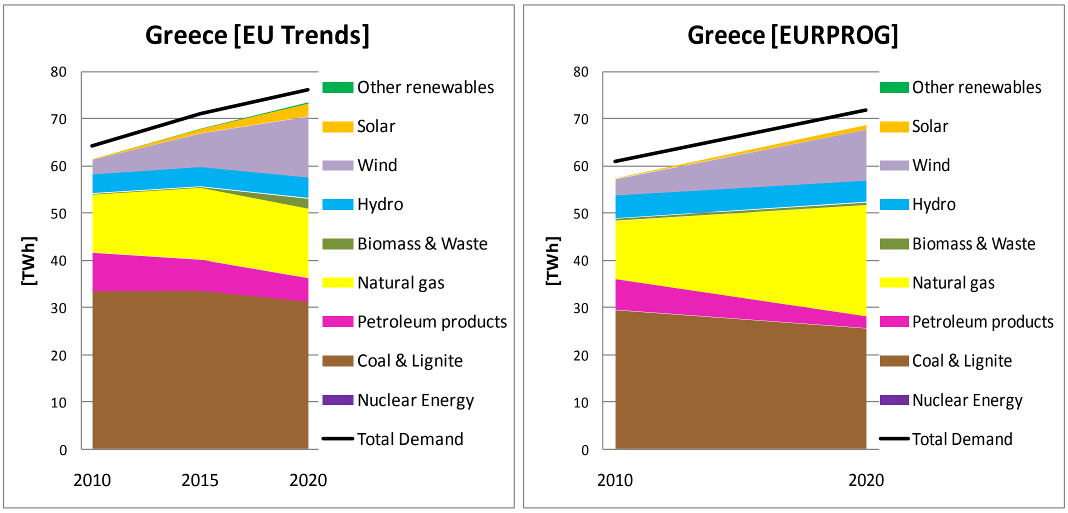


Figure 53: Electricity generation development in Greece

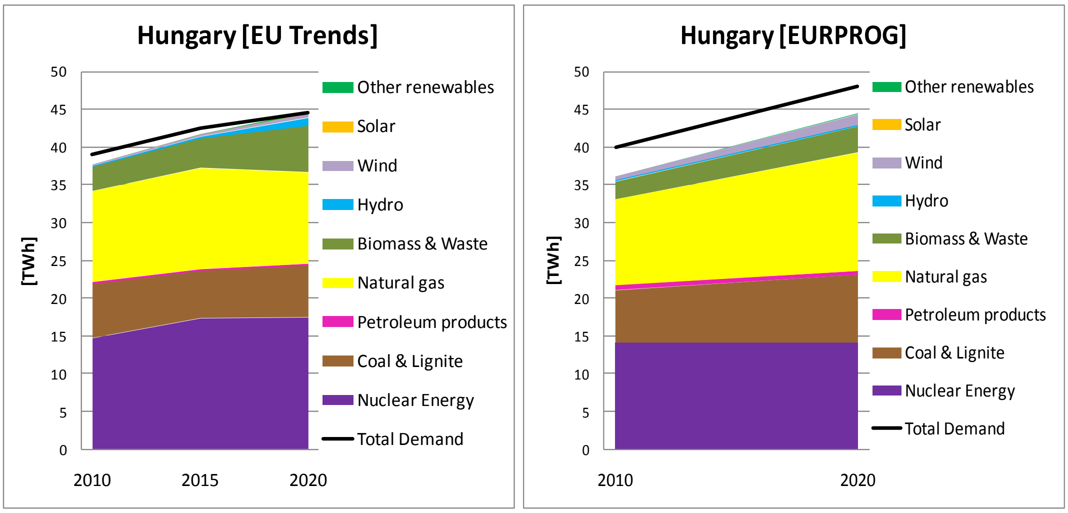


Figure 54: **Electricity generation development in Hungary**

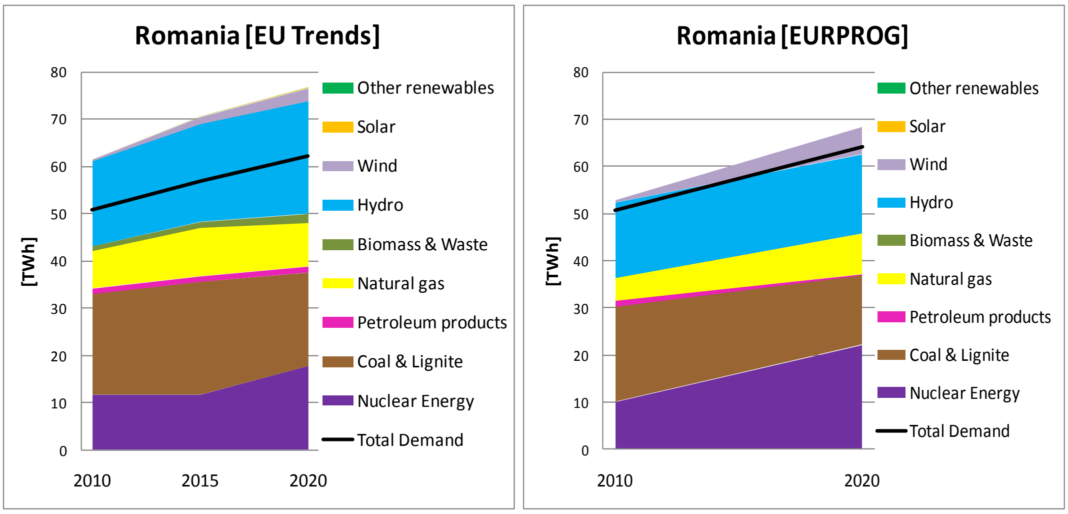


Figure 55: **Electricity generation development in Romania**

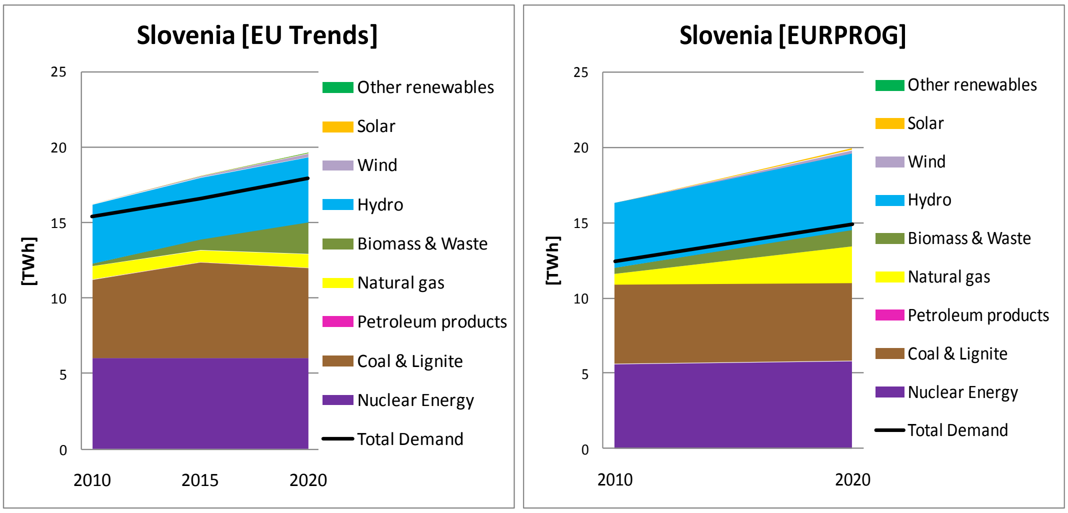


Figure 56: **Electricity generation development in Slovenia**

Also for the analysed South East European countries more or less substantial differences between the figures as given by the two data sources can be found. In particular, also the development of the composition of electricity generation by fuel type can differ quite a lot.

Except for Slovenia, the electricity generation values for 2010 already differ significantly, as shown in Figure 57, where the 2010 electricity generation figures of all South East European countries are compared with the ones by [Eurostat], to see the differing assumptions for electricity amounts in 2010 by fuel type. Again, [Eurostat]'s subsumed 'combustible fuels' category is illustrated in Figure 57 with striped blocks within the bar charts for [Eurostat].

It turns out that the 2010 generation values for Bulgaria are slightly better met by [EU Trends] whereas the 2010 values for Greece, Hungary and Romania are better matched by [EURPROG]. The same result is also confirmed when total generated electricity values for 2010 by [EU Trends] and [EURPROG] are compared with statistical values for electricity generation published by [ENTSO-E].

As a result we can assume that net electricity imports in 2010 have probably been higher in Hungary as indicated by [EU Trends] and, particularly in Romania, net electricity exports have been considerably lower than indicated by [EU Trends].

From the presented development of electricity demand figures in [EURPROG], it can be seen that electricity generation more or less keeps pace with electricity demand development for all countries (cf. Figure 52 to Figure 56). All countries are forecast to keep their status up to 2020 as either net electricity exporters (Bulgaria, Romania, Slovenia) or net electricity importers (Greece, Hungary).

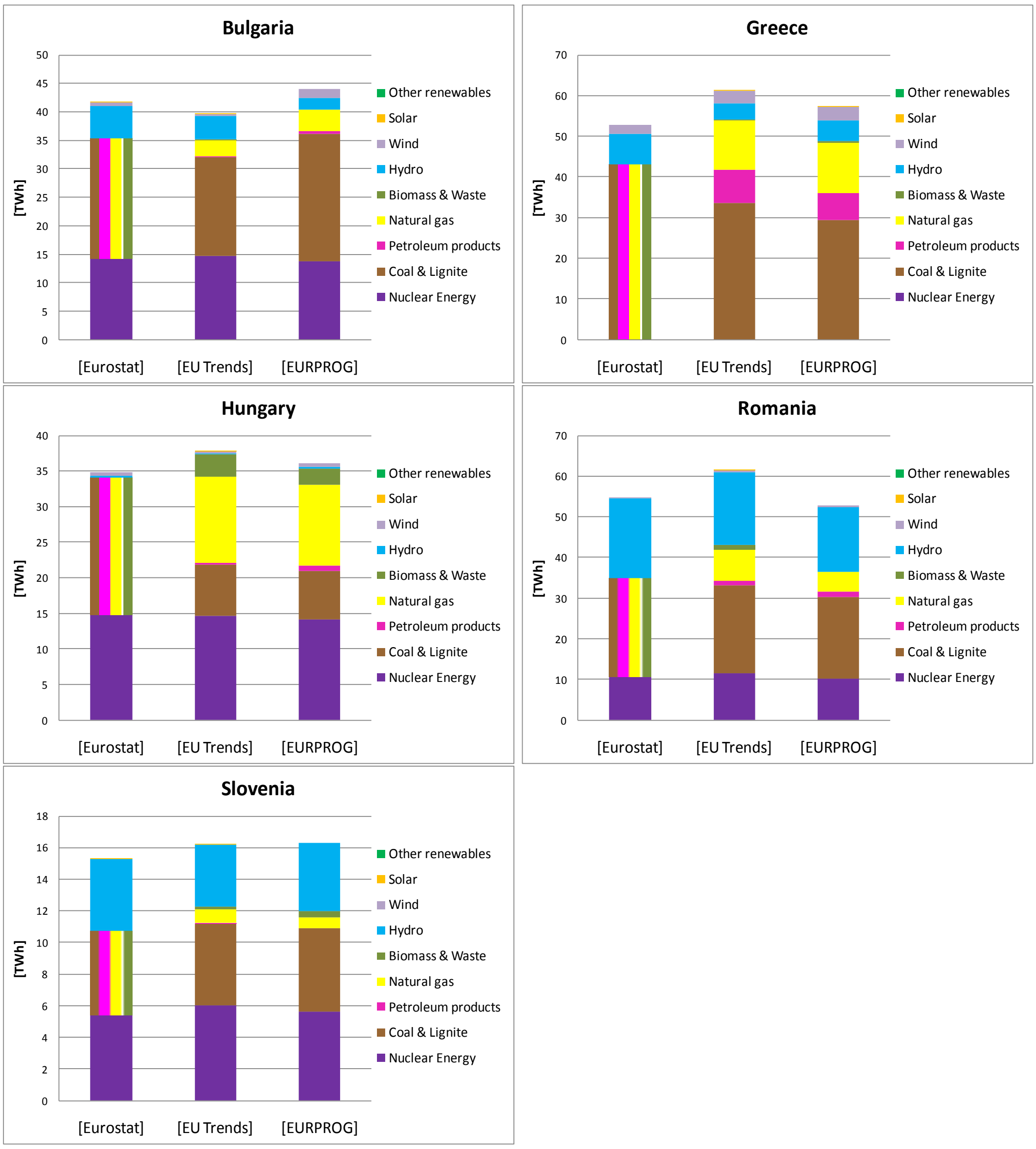


Figure 57: Electricity generation 2010 in South East European countries

In both scenarios, all countries can expect to increase their electricity generation by about 20% to 30%, except for Bulgaria which is forecast by [EURPROG] to increase generation even by 49% (cf. Table 27). The largest electricity producers at present are Greece and Romania, and the smallest is Slovenia. In total, between 46.6 TWh (+22%) and 60.5 TWh (+29%) more electricity generation is expected in the South East European countries.

Generation by country	2010 [EU Trends] [GWh]	2010 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [GWh]	net additions until 2020 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Bulgaria	39,688	44,100	8,839	21,800	22%	49%
Greece	61,331	57,300	12,046	11,300	20%	20%
Hungary	37,696	36,100	7,000	8,400	19%	23%
Romania	61,460	52,900	15,301	15,400	25%	29%
Slovenia	16,192	16,300	3,452	3,600	21%	22%
Total	**216,367**	**206,700**	**46,638**	**60,500**	**22%**	**29%**

Table 27: Electricity generation development in South East European countries

By fuel type, the largest electricity generation increases in the South East European countries will again come from nuclear energy (see Table 28), as is also the case for North East European countries (cf. above). There are enormous differences between the two scenarios regarding assumptions for future electricity additions from natural gas power plants. Like for the North East European countries, [EURPROG] is again much more optimistic for future additional electricity generation from natural gas (+22.8 TWh) up to 2020 in the South East European countries. [EU Trends] only expects +4 TWh more electricity from natural gas in 2020. Both studies expect declines in coal-based electricity of between 5.4 and 5.6 TWh by 2020.

In total, the South East European countries are now and will be in the future generating more electricity than demanded according to both scenarios and they are expected to increase their net electricity exports (see Figure 58).

Generation by fuel	2010 [EU Trends] [GWh]	2010 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [GWh]	net additions until 2020 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Nuclear Energy	47,008	43,600	16,493	26,900	35%	62%
Coal & Lignite	84,727	84,100	-5,370	-5,600	-6%	-7%
Petroleum products	9,649	9,100	-3,126	-5,400	-32%	-59%
Natural gas	35,908	33,100	3,957	22,800	11%	69%
Biomass & Waste	4,718	3,100	9,216	2,100	195%	68%
Hydro	30,141	27,600	7,630	1,700	25%	6%
Wind	4,108	6,000	14,307	16,900	348%	282%
Solar	108	100	2,948	1,000	2730%	1000%
Other renewables	0	0	583	100	n.a.	n.a.
Total	**216,367**	**206,700**	**46,638**	**60,500**	**22%**	**29%**

Table 28: Electricity generation development by fuel type in South East European countries

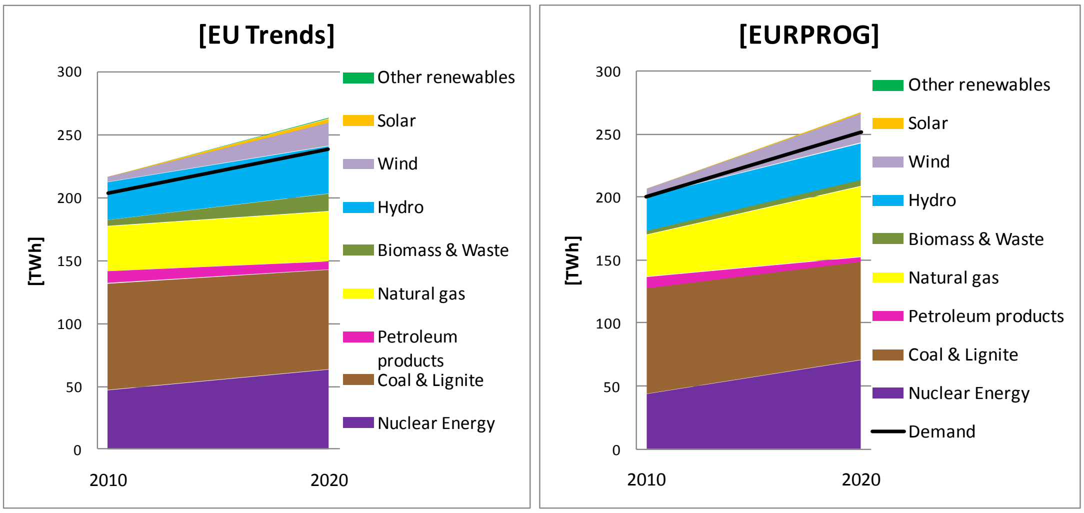


Figure 58: Electricity generation development in South East European countries

3.3.3.3 Mediterranean countries

Figure 59 and Figure 60 show the future development of electricity generation by fuel type up to 2020 in Italy and Spain as outlined by [EU Trends] and by [EURPROG].

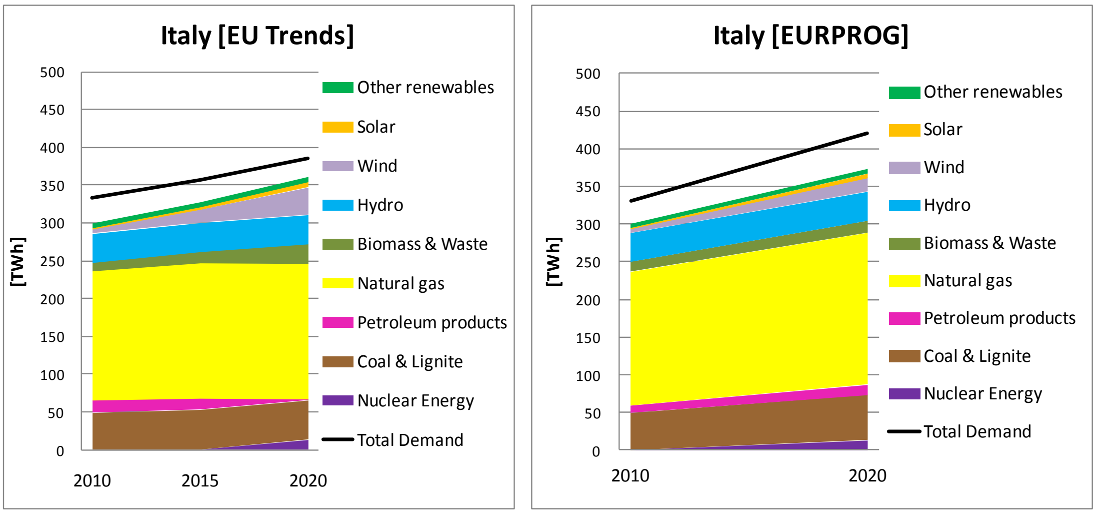


Figure 59: Electricity generation development in Italy

For Italy, total electricity generation figures by the two data sources almost agree, although the composition of electricity generation by fuel type develops differently up to 2020. And particularly the electricity demand increase up to 2020 is seen to be much lower by [EU Trends] than by [EURPORG].

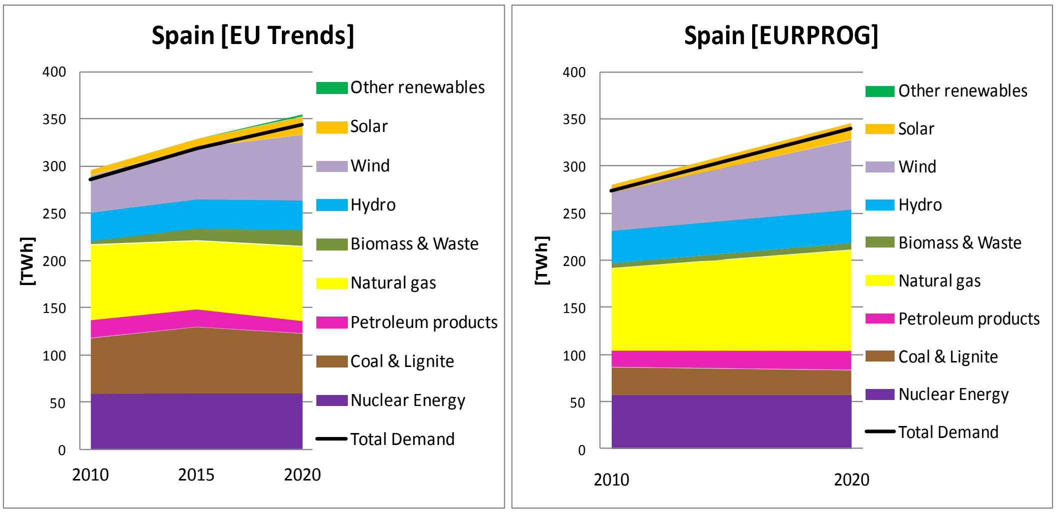


Figure 60: Electricity generation development in Spain

For Spain, too, discrepancies between the future development of electricity generation and its make-up by fuel type are apparent. Even the electricity generation values for 2010 already differ significantly for Spain, as shown by the comparison in Figure 61 with the figures from [Eurostat]. Again, [Eurostat]'s subsumed 'combustible fuels' category is illustrated in Figure 61 with striped blocks in the bar charts for [Eurostat].

It turns out that the 2010 generation value for Spain is better matched by [EURPROG] than by [EU Trends]. This is confirmed when the total electricity generated in 2010 in Spain is compared with the relevant statistical value published by [ENTSO-E].

From the presented development of electricity demand figures, it can be seen that electricity generation roughly keeps pace with electricity demand development for both countries (cf. Figure 59 and Figure 60). That's why Italy is forecast to remain a net electricity importer up to 2020 and Spain will continue to almost balance its own electricity demand with its own electricity generation.

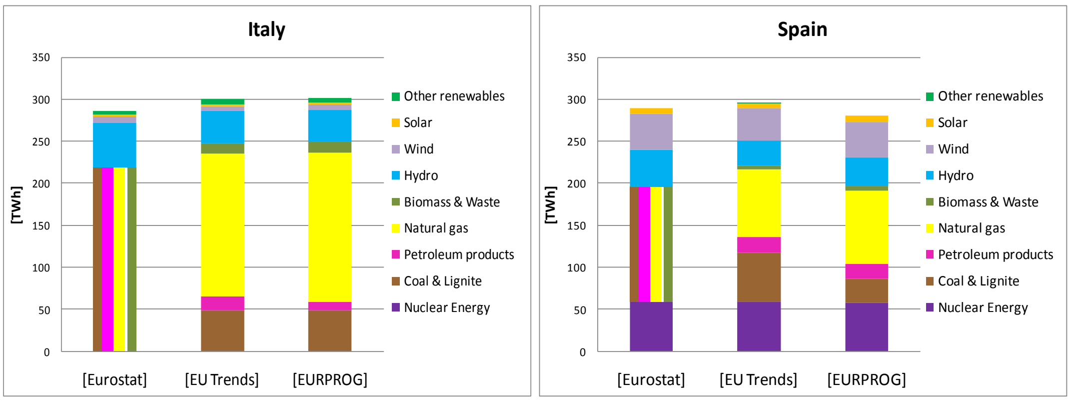


Figure 61: Electricity generation in 2010 in Mediterranean countries

[EU Trends] sees for both countries an electricity generation increase of about 20% and [EURPROG] one of about 23%-24% (cf. Table 29). In total, between 120.1 TWh and 137.1 TWh more electricity generation is expected in the Mediterranean countries.

Generation by country	2010 [EU Trends] [GWh]	2010 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [GWh]	net additions until 2020 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Italy	300,117	301,000	60,917	72,400	20%	24%
Spain	295,437	280,400	59,187	64,700	20%	23%
Total	**595,554**	**581,400**	**120,104**	**137,100**	**20%**	**24%**

Table 29: Electricity generation development in Mediterranean countries

By fuel type, the largest electricity generation increases in the Mediterranean countries are expected from wind power and solar power plants, except for [EURPROG] which also indicates large expansions of electricity generation from natural gas (+43.3 TWh, cf. Table 30). [EU Trends], however, favours substantially more electricity generation from biomass and waste. For coal-based electricity, both studies expect increases.

Generation by fuel	2010 [EU Trends] [GWh]	2010 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [GWh]	net additions until 2020 [EURPROG] [GWh]	net additions until 2020 [EU Trends] [%]	net additions until 2020 [EURPROG] [%]
Nuclear Energy	58,619	57,500	14,247	13,600	24%	24%
Coal & Lignite	107,638	78,100	7,355	7,500	7%	10%
Petroleum products	35,947	27,500	-21,131	7,100	-59%	26%
Natural gas	250,277	264,700	7,579	43,300	3%	16%
Biomass & Waste	15,960	18,100	27,991	4,700	175%	26%
Hydro	67,868	72,600	1,809	1,500	3%	2%
Wind	45,433	47,600	61,134	45,500	135%	96%
Solar	7,369	9,800	18,553	13,300	252%	136%
Other renewables	6,443	5,500	2,567	600	40%	11%
Total	**595,554**	**581,400**	**120,104**	**137,100**	**20%**	**24%**

Table 30: Electricity generation development by fuel type in Mediterranean countries

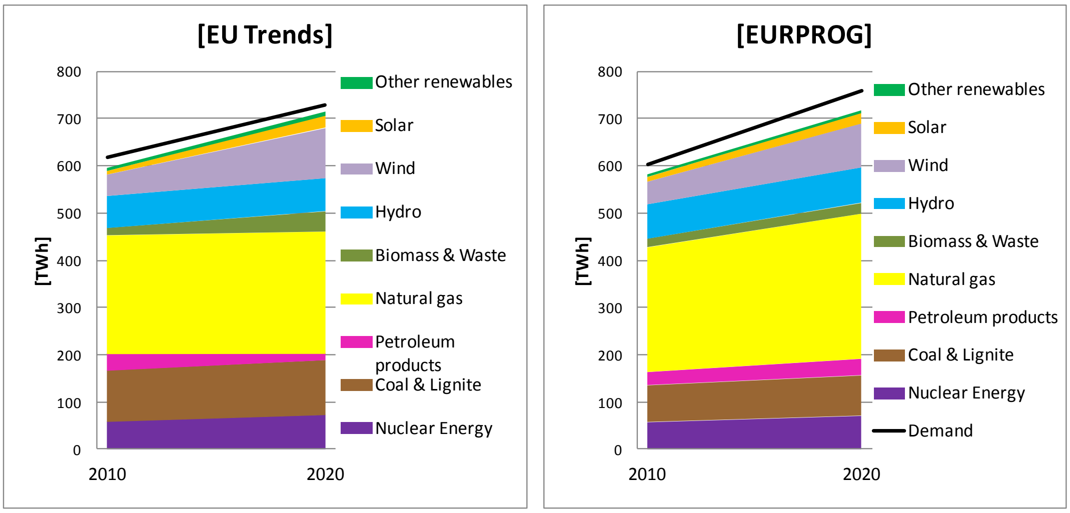


Figure 62: Electricity generation development in Mediterranean countries

3.3.3.4 Summary: Development of electricity generation

In summary, it can be stated that electricity generation is generally expected to increase in all of the selected EU countries by 2020, with the highest growth rates anticipated particularly in the Baltic countries. Otherwise, the expected growth rates do not differ too much between the regional clusters and also between the two scenarios presented by [EU Trends] and by [EURPROG] (see Table 31). [EURPROG] generally represents the slightly more optimistic view on additional future electricity generation with +26% vs. +21% by [EU Trends]) and this particularly for power from natural gas-fired power plants. Accordingly, the additional electricity from natural gas in 2020 may be up to 90.3 TWh as indicated by [EURPROG] or only 6.4 TWh according to [EU Trends].

This difference between the two studies is even greater than their total forecast discrepancy, which is 228.2 TWh additional electricity production predicted by [EU Trends] and 275 TWh predicted by [EURPROG]. [EU Trends] for its part anticipates much more electricity generation expansion from renewables, particularly from biomass & waste fuelled power plants and also more solar power generation (cf. Table 32). [EURPROG] on its part particularly predicts a reduction of electricity production from coal (-17.2 TWh). At least no significant increase of electricity generated from coal is anticipated according to [EU Trends].

Generation	2010		net additions until 2020		net additions until 2020	
	[EU Trends] [GWh]	[EURPROG] [GWh]	[EU Trends] [GWh]	[EURPROG] [GWh]	[EU Trends] [%]	[EURPROG] [%]
North East	296,632	262,500	61,458	77,400	21%	29%
South East	216,367	206,700	46,638	60,500	22%	29%
Mediterranean	595,554	581,400	120,104	137,100	20%	24%
Total	**1,108,553**	**1,050,600**	**228,200**	**275,000**	**21%**	**26%**

Table 31: Electricity generation development in all selected EU countries

Generation by fuel	2010		net additions until 2020		net additions until 2020	
	[EU Trends] [GWh]	[EURPROG] [GWh]	[EU Trends] [GWh]	[EURPROG] [GWh]	[EU Trends] [%]	[EURPROG] [%]
Nuclear Energy	142,871	136,600	69,158	87,100	48%	64%
Coal & Lignite	361,829	308,500	1,647	-18,900	0%	-6%
Oil Shale	9,824	9,800	290	1,700	3%	17%
Petroleum products	48,578	38,000	-25,878	1,800	-53%	5%
Natural gas	318,383	330,100	6,389	90,300	2%	27%
Biomass & Waste	39,970	33,000	57,511	11,200	144%	34%
Hydro	121,480	122,200	10,449	5,000	9%	4%
Wind	51,682	57,000	83,620	81,600	162%	143%
Solar	7,493	9,900	21,667	14,400	289%	145%
Other renewables	6,443	5,500	3,347	800	52%	15%
Total	**1,108,553**	**1,050,600**	**228,200**	**275,000**	**21%**	**26%**

Table 32: Electricity generation development by fuel type in all selected EU countries

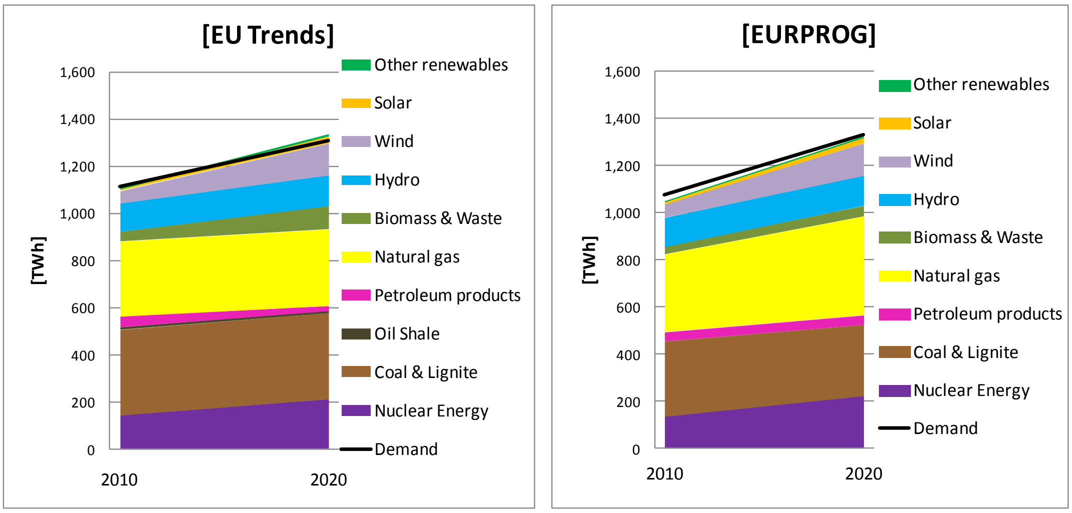


Figure 63: Electricity generation development in all selected EU countries

In total, over all selected EU countries, the electricity generation increase is outpacing the demand increase up to 2020 and this is indicated in both studies (see Figure 63). Growth rates for generation of 21% [EU Trends] and 26% [EURPROG] are to be compared with growth rates for demand of only 18% [EU Trends] and 23% [EURPROG] (cf. Table 6). The main difference is that [EU Trends] sees the countries in sum almost already now to be almost net electricity exporters whereas [EURPROG] is not expecting this before 2020.

This trend towards more and more electricity exports is mainly driven by the North East and South East European countries, which are either going to keep their status as net electricity exporting regions (as is the case for South East European countries) or are going to achieve it by2020. Net importers in 2010 are only the Mediterranean countries and it is expected that they will retain and even expand that status at least until 2020.

Combining the analysis of sections 3.3.2 and 3.3.3 and the results from the two studies, [EU Trends] and [EURPROG], regarding future development of power capacities and generation, it is noted that the development of total electricity generation and of generation capacities seems to be better determined than the composition of future electricity generation.

The quite different results from country to country but also in sum, as obtained from the two data sources, [EU Trends] and [EURPROG], cannot be explained. The reason is that neither the scenario methods nor the basis of expert judgement impacting the results of both studies are sufficiently transparent. This holds particularly for [EURPROG], for which the scenario may be obtained with different approaches and assumptions from the EURELECTRIC members in the various countries. [EU Trends] refers to a scenario framework that explicitly includes the latest climate policy measures on EU level but also the mandatory national greenhouse gas emission and energy targets set for 2020. So, to include the impact of these policies on the anticipated power plant investment behaviour in the proximity of the EU boundaries, the [EU Trends] scenario is taken as a reference for this study.

3.4 Need for Investments in New Power Capacities

In section 3.3 of this report, the future development of electricity supply is investigated. This embraces anticipated power plant retirements, net capacity additions and the associated development of electricity generation up to 2020 for all selected EU countries. In this section, the needs for new gross capacity additions up to 2020 are derived from this analysis.

Needed capacity additions are determined as net additions of capacities[4] plus the necessary replacement of power plants that are going to be retired by 2020. Regarding net additions, the two scenarios given by [EU Trends] and [EURPROG] were compared and analysed in section 3.3.2. Capacity figures of these two data sources are expressed in net electrical capacities. Power plant retirements, though, were calculated from [WEPP] as presented in section 3.3.1 and are expressed in gross electrical capacities.

In order to calculate only with comparable figures that are all expressed as net electrical capacities[4] and to maintain data consistency within datasets taken only from the same data sources, the following approach is taken:

1. For each selected EU country and for each power plant technology as classified by its fuel type, the relative capacity retirement from 2010 to 2020 as a%age as derived from [WEPP] (cf. section 3.3.1) is applied to the respective power plant capacities installed in 2010 as listed by [EU Trends]. This yields an estimate of the capacity retirement up to 2020 as given by [EU Trends]. To these '[EU Trends] capacity retirements' the net additions from the [EU Trends] Scenario are added in order to obtain '[EU Trends] gross additions of capacities by 2020' which represent the need for investments according to [EU Trends]. The results are presented in section 3.4.1

2. The same approach is applied with data of [EURPROG] instead of [EU Trends] in order to obtain '[EURPROG] gross additions of capacities by 2020' which represent the needs for investments according to [EURPROG]. These results are also presented in section 3.4.1.

3. After comparing the two scenarios, the [EU Trends] Scenario is selected due to its relevance for this study and because the methodological approach applied in [EURPROG] is not transparent enough. The needs for new capacity investments based on [EU Trends] are thus further analysed in section 3.4.2.

[4] 'Capacity net additions' should not be confused with 'net electrical capacity'. The latter term is defined for each power plant as its gross electrical capacity less the electrical power required for the operation of the power plant itself. 'Net additions' of capacities, though, refer to gross additions of new power plant capacities less decommissioned power plant capacities. 'Capacity net additions' are therefore identical to the effective overall capacity increase or decrease.

3.4.1 Need for new power plant capacities derived from [EU Trends] and [EURPROG]

The need for new power capacities by 2020 as derived from [EU Trends] and from [EURPROG] are presented in Figure 64 and Figure 65, respectively. The figures are given in net electrical power plant capacities.

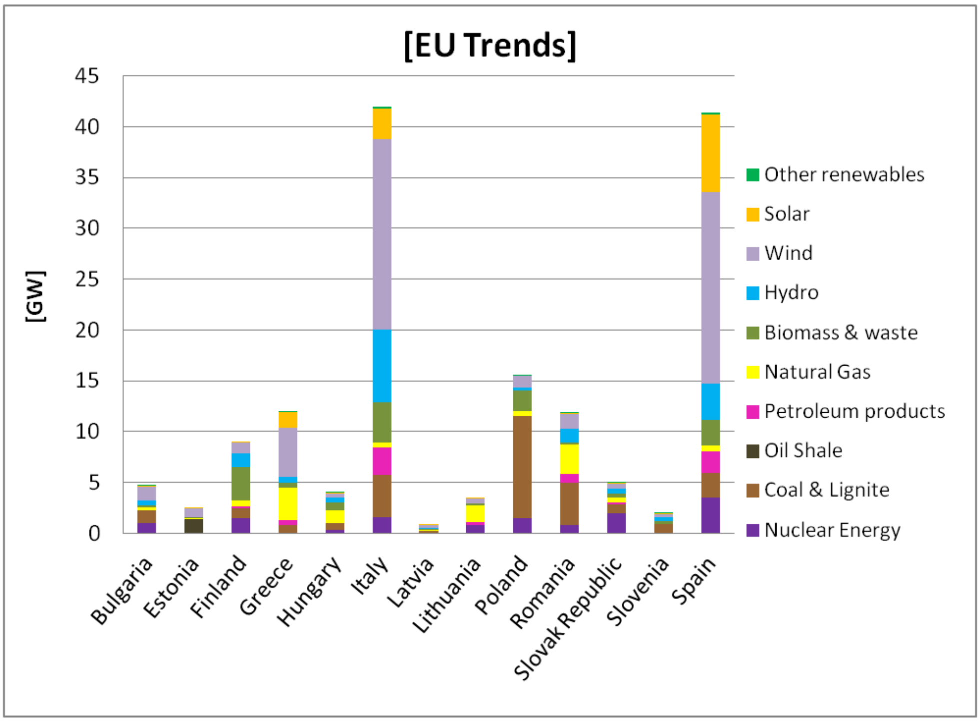


Figure 64: Need for new power plant capacities by country: [EU Trends] Scenario

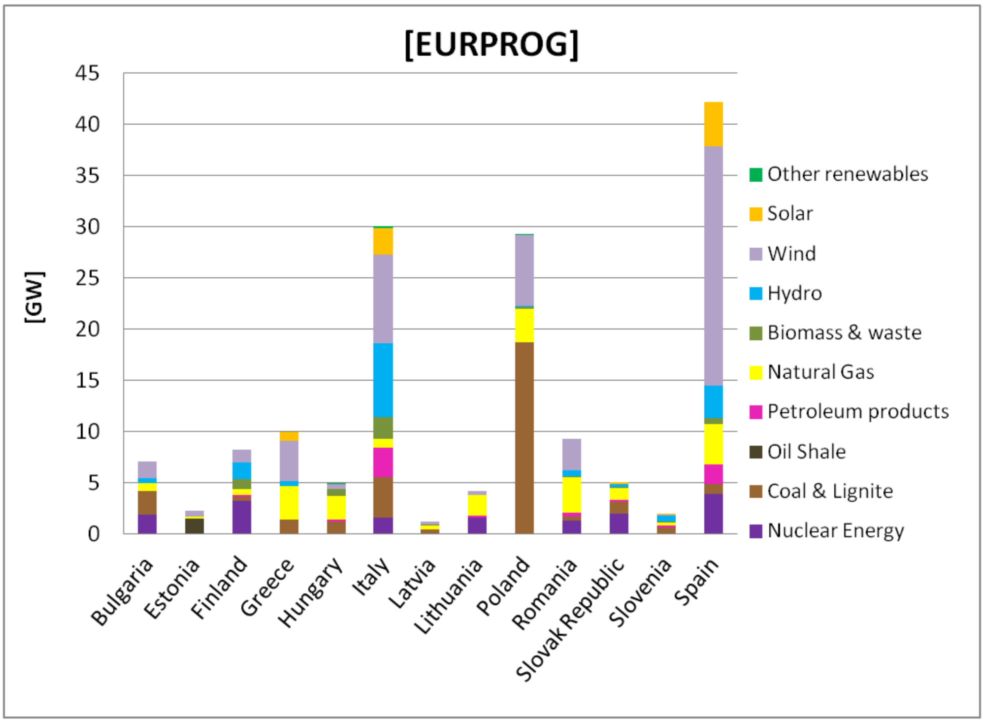


Figure 65: Need for new power plant capacities by country: [EURPROG] Scenario

At first glance, the different roles that Italy and Poland play in both scenarios become visible. [EU Trends] determined much more net additions for Italy than [EURPROG] did. Instead [EURPROG] assumes considerably more net additions for Poland so that Italy and Poland almost require the same amount of new power plant capacities at a level of about 30 GW by 2020 as calculated for the [EURPROG] Scenario. The high requirement for new power plant capacities in Spain of about 41 to 42 GW is confirmed by both scenarios. Apart from this, large differences between the two scenarios not only for the absolute amount of new power plant requirements but also for the required type of power plants are noted for almost all countries.

Instructive is an analysis of required new power plant capacities by fuel type and country, as compared for both scenarios in Table 33 and Table 34. Interestingly, the identified investment needs for power plants by almost all fuel types are not all that different between [EU Trends] and [EURPROG] if summed up over all the considered EU countries. Major differences are only obtained for investments in new natural gas fired power plants and in new biomass and waste power plants. The first are preferred by [EURPROG] by an increment of about 10.5 GW and the latter are preferred by [EU Trends] by an increment of about 9.7 GW. To a minor degree, [EU Trends] also sees more chances for solar power plant additions (increment 4.6 GW), whereas [EURPROG] foresees about 5.2 GW more investments in coal power plants (the latter particularly for Poland, cf. section 3.3.2.1). Clearly [EU Trends] anticipates generally more additions of renewable power plants whereas [EURPROG] focuses more on fossil fuel-fired power plant additions.

Despite net capacity additions, although coal power plants are in general perceived to be on a slightly decreasing trend as implied at least by [EU Trends] (and apart from the case of Poland also by [EURPROG], cf. section 3.3.2.4 and Table 24), it is the technology with the second highest capacity additions required by 2020 in the selected EU countries. More investments in terms of GW capacity are only predicted for wind power (ca. 50 GW) (see Table 33 and Table 34).

There is almost no difference between the total new power plant capacity needs between the two scenarios and these are close at 153.8 GW [EU Trends] and 155.4 GW [EURPROG].

[EU Trends] new power plant capacities [MW]	Nuclear Energy	Coal & Lignite	Oil Shale	Petroleum products	Natural Gas	Biomass & waste	Hydro	Wind	Solar	Other renewables	Total
Bulgaria	985	1,269	0	0	246	243	484	1,347	70	7	**4,651**
Estonia	0	0	1,331	0	123	118	1	822	2	0	**2,397**
Finland	1,516	957	0	168	587	3,221	1,434	1,050	76	0	**9,010**
Greece	0	746	0	537	3,227	436	609	4,799	1,526	31	**11,911**
Hungary	320	650	0	0	1,259	818	409	413	76	22	**3,967**
Italy	1,579	4,127	0	2,698	525	3,935	7,161	18,778	2,930	270	**42,003**
Latvia	0	229	0	25	25	155	73	318	8	0	**833**
Lithuania	758	0	0	314	1,666	159	26	487	36	0	**3,446**
Poland	1,515	9,987	0	0	543	2,034	255	1,177	17	16	**15,543**
Romania	752	4,183	0	923	2,823	185	1,431	1,370	156	6	**11,829**
Slovak Republic	1,912	954	0	110	481	452	458	506	27	7	**4,908**
Slovenia	0	873	0	2	0	288	439	254	47	4	**1,907**
Spain	3,471	2,420	0	2,120	619	2,530	3,548	18,898	7,589	243	**41,437**
Total	**12,808**	**26,395**	**1,331**	**6,897**	**12,124**	**14,573**	**16,328**	**50,220**	**12,560**	**606**	**153,842**
North East	**5,701**	**12,127**	**1,331**	**617**	**3,425**	**6,139**	**2,247**	**4,360**	**166**	**23**	**36,136**
South East	**2,057**	**7,721**	**0**	**1,462**	**7,555**	**1,970**	**3,372**	**8,184**	**1,875**	**70**	**34,265**
Mediterranean	**5,050**	**6,547**	**0**	**4,817**	**1,144**	**6,465**	**10,709**	**37,676**	**10,519**	**513**	**83,440**

Table 33: Need for new power plant capacities for the [EU Trends] Scenario

[EURPROG] new power plant capacities [MW]	Nuclear Energy	Coal & Lignite	Oil Shale	Petroleum products	Natural Gas	Biomass & waste	Hydro	Wind	Solar	Other renewables	Total
Bulgaria	1,900	2,325	0	0	773	0	470	1,617	0	0	**7,085**
Estonia	0	0	1,515	0	171	30	1	527	0	0	**2,244**
Finland	3,205	446	0	147	556	980	1,643	1,260	0	0	**8,237**
Greece	0	1,382	0	0	3,248	14	491	3,977	840	0	**9,952**
Hungary	0	1,241	0	129	2,360	630	30	470	0	20	**4,880**
Italy	1,579	3,935	0	2,878	928	2,111	7,161	8,670	2,580	200	**30,042**
Latvia	0	400	0	0	425	50	70	237	0	0	**1,182**
Lithuania	1,600	0	0	196	2,016	9	0	369	0	0	**4,190**
Poland	0	18,691	0	0	3,258	210	93	6,884	0	1	**29,137**
Romania	1,330	365	0	350	3,525	30	622	3,095	0	0	**9,316**
Slovak Republic	1,988	1,170	0	156	1,129	114	269	70	117	0	**5,013**
Slovenia	0	656	0	169	305	53	583	104	127	0	**1,997**
Spain	3,911	967	0	1,875	3,944	631	3,187	23,298	4,317	0	**42,130**
Total	**15,513**	**31,578**	**1,515**	**5,900**	**22,636**	**4,861**	**14,620**	**50,579**	**7,981**	**221**	**155,403**
North East	**6,793**	**20,707**	**1,515**	**500**	**7,555**	**1,392**	**2,076**	**9,347**	**117**	**1**	**50,001**
South East	**3,230**	**5,969**	**0**	**648**	**10,210**	**727**	**2,196**	**9,263**	**967**	**20**	**33,230**
Mediterranean	**5,490**	**4,903**	**0**	**4,753**	**4,871**	**2,742**	**10,348**	**31,968**	**6,897**	**200**	**72,172**

Table 34: Need for new power plant capacities for the [EURPROG] Scenario

3.4.2 Scenario for new power plant capacity requirements

The quite different results from country to country but also in sum obtained from the two data sources, [EU Trends] and [EURPROG], cannot be explained. The reason is that neither the scenario methods nor the basis of expert judgement impacting the results of the two studies are transparent enough. This holds particularly for [EURPROG], for which the scenario may be obtained with different approaches and assumptions from the EURELECTRIC members in the various countries.

[EU Trends] refers to a scenario framework that explicitly includes the latest climate policy measures on EU level but also the mandatory national greenhouse gas emission and energy targets set for 2020. This is also reflected in the fact, that according to the scenario based on [EU Trends], higher capacity requirements for low CO_2 emission technologies such as biomass power plants and solar power are identified, whereas [EURPROG] sees more new capacity requirements for fossil fuel-fired power plants. Interesting to note is that, according to both scenarios, the identified requirements for new wind power plants in the EU countries concerned are almost identical for both scenarios at more than 50 GW, but their allocation of these new capacity requirements to the countries is quite different.

This study focuses on the analysis of the impact of the European Emission Trading Scheme on power plant investments, given EU policies on national greenhouse gas emission and energy targets set for 2020. Since this is only explicitly reflected in the scenario as set out by [EU Trends], the calculated [EU Trends] Scenario for capacity investment requirements (see Table 33) is thus selected as being the relevant scenario for the purpose of this study.

According to the [EU Trends] Scenario, the total 153.8 GW capacity gap from 2010 to 2020 is expected to be filled mainly by about 50.2 GW wind power plant investments and about 26.4 GW coal power plant investments (cf. Table 33). Wind power capacity additions focus on the two Mediterranean countries Italy and Spain, whereas investments in new coal fired power plants concentrate particularly on Poland.

Apart from these two power plant technologies (wind power and coal power plants), further significant market shares for new power plant erections are predicted for hydropower (16.3 GW, with the largest shares in the two Mediterranean countries) and biomass and waste power plants (1.6 GW, with significant shares in Italy and Finland). Required new capacities for nuclear energy, solar power and natural gas fired power plants all amount to about 12 GW. New solar power capacities will be particularly concentrated in the Mediterranean countries and new natural gas power plants in South East European countries, particularly in Greece and Romania. New nuclear power plants are particularly required in the North East European countries, but also in the Mediterranean countries.

As a result of the methodology applied it turns out that Estonia is expected to build about 1.3 GW new oil shale-fired power plants, which is about 65% of its installed capacity in 2010. This is not regarded to be realistic and actually virtually no new oil shale-fired power plant investments are expected for Estonia up to 2020. But since the age of the oil shale-fired power plants in Estonia according to [WEPP] indicates substantial retirements of this type of power plant and since, in contrast, [EU Trends] implies a much lower retirement of these power plant capacities, it turns out by the applied calculation that new capacities are needed in order to fill the gap between existing decreasing capacities indicated by [WEPP] and higher total installed capacities as outlined by [EU Trends]. Such constructive vagueness is a result of the method applied.

The regional focus is illustrated by the three figures below (Figure 66 to Figure 68), which show the shares of new power plant capacity additions for each country cluster considered.

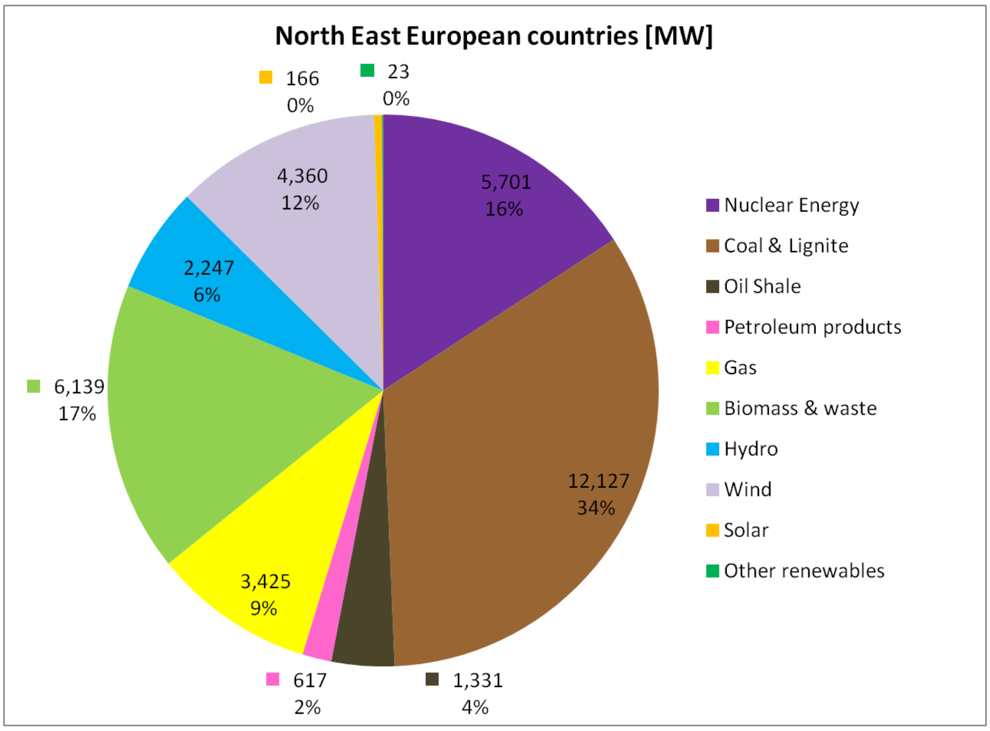


Figure 66: New power plant capacities up to 2020 in North East European countries

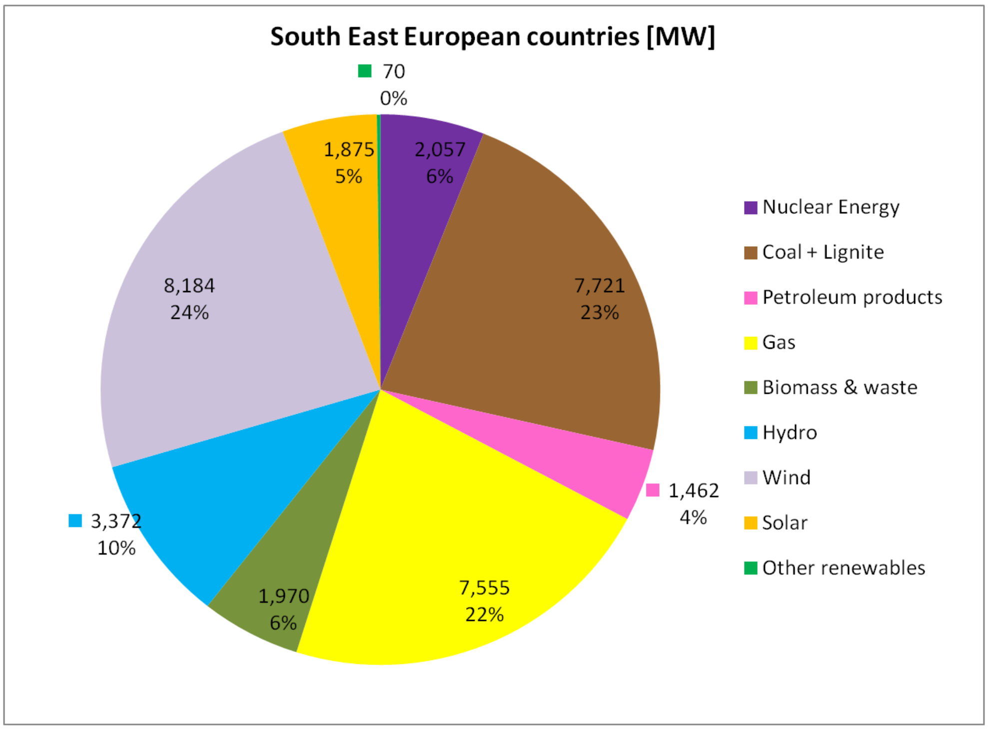


Figure 67: New power plant capacities up to 2020 in South East European countries

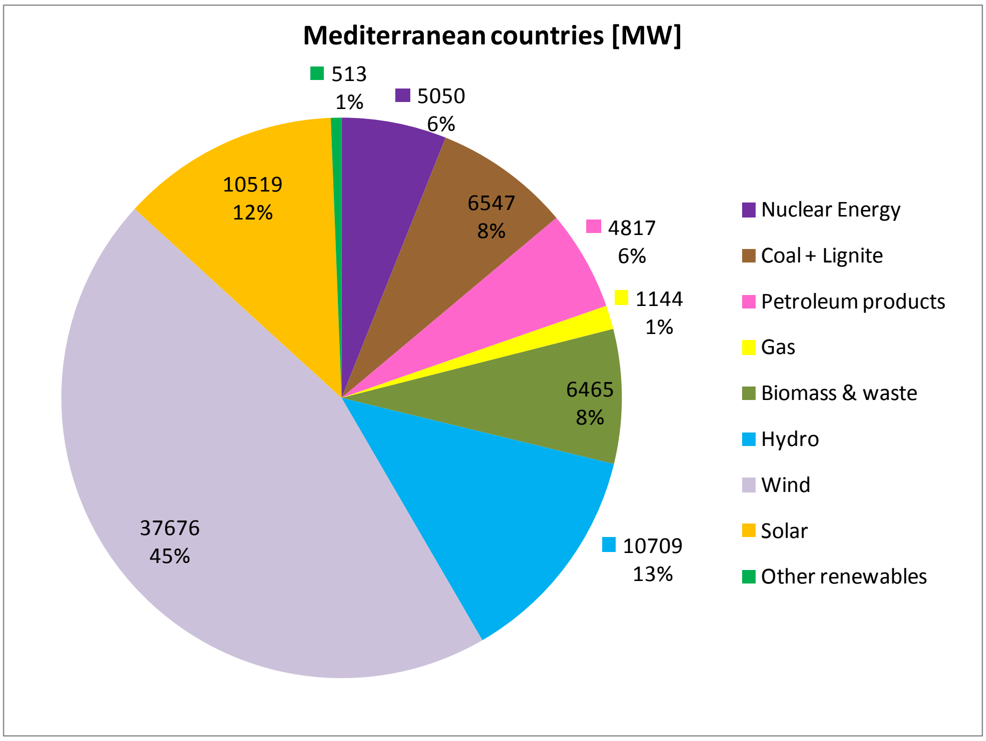


Figure 68 : New power plant capacities up to 2020 in Mediterranean countries

As shown by these three figures, power plant investments in North East European countries will be dominated by new coal power plants and in Mediterranean countries by new wind power plants. In the South East European countries both technologies, coal power plants and wind power plants, are dominant too. But additionally also new natural gas-fired power plants play a major role in South East Europe.

Finally, Figure 69 depicts the shares of the country clusters regarding the capacity gaps to be filled by 2020. 54% of new power plant capacities of the selected EU countries are required in the two Mediterranean countries, 24% in the six North East European countries and 22% in the five South East European countries. This means that the two Mediterranean countries are the main ones of the thirteen selected in which more than 50% of all new power plant capacities are expected by 2020.

This is, though, in accordance with the electricity demand of the thirteen EU countries investigated, which is also to more than 50% allocated to the two Mediterranean countries. Table 35 compares the shares that the country clusters have on the total electricity demand and on the new capacities as derived from the [EU Trends] data.

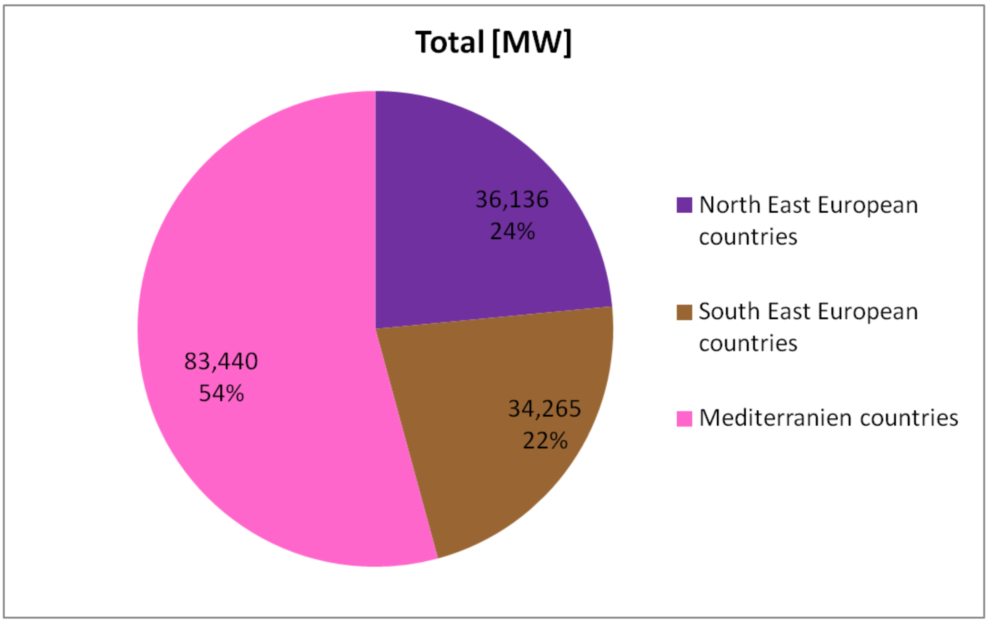


Figure 69: New power plant capacities up to 2020 by country cluster

	electricity demand	new capacities
North East	26%	23%
South East	18%	22%
Mediterranean	56%	54%
Total	**100%**	**100%**

Table 35: Electricity demand and new capacities up to 2020 by country cluster shares, as derived from [EU Trends].

3.5 Conclusions on Power Plant Capacity Needs

In this chapter the development of electricity demand and supply in the selected EU countries is investigated. The analysis is done for those particular EU member states that either already have electricity interexchange or at least have future electricity interexchange options across direct borders or overseas to non-EU countries.

For the sake of clarity, the selected EU countries are classified into three country clusters: North East European, South East European and Mediterranean countries. As it turns out ex post, the proposed clustering is reasonable in the sense that countries with similar characteristics are bundled within the clusters.

Regarding power plant capacities and their development in the selected EU countries, the analysed data sources [EU Trends] and [EURPROG] are ambiguous. This highlights the restricted predictive power of the predetermined scenarios outlined by the two studies. But also figures for 2010 already vary significantly from study to study. By comparison with statistical data, no clear preference for one or the other study can be found.

Despite comprising only two countries and having the lowest%age net capacity additions up to 2020 in relative terms (+18%), in absolute figures the Mediterranean countries will face the highest capacity net additions of about 35 GW according to [EU Trends]. In total, for all analysed EU countries, about 62 GW net additions are projected according to [EU Trends]. Positive capacity net additions focus mainly on wind power, solar power and biomass power plants. Apart from renewable technologies also nuclear power plants belong to the technologies with high capacity net additions for all selected EU countries. In contrast, fossil fuel-fired power plant capacities, particularly coal power plant capacities, are predicted to contract and capacities for power plants fuelled with petroleum products are even scheduled to almost halve by 2020.

The increase of installed power plant capacities (net additions) constitutes only one driving force for new power plant investments, the other being replacement of retiring capacities. Expected retirements of power plants up to 2020 are derived from [WEPP]. Retirement rates are highest for North East European countries (38%) followed by South East European countries (32%) and Mediterranean countries (25%). For some types of power plants, determined retirement rates are considerably higher. Apart from petroleum fuelled power plants (76%), the highest retirement rates are found for coal-fired power plants: 41% of these in the selected EU countries are going to be decommissioned by 2020.

So, although almost no capacity expansions for coal power plants can be expected, the need for new coal power plants is generally high due to the need for replacement of retiring capacities. This conclusion is drawn from the calculation of new power plant capacities that are required for filling the gap of a) retiring capacities and b) of positive net additions.

Required new power plant capacities are first calculated twice based on the two data sources that offer capacity figure estimates for all countries for 2010 and 2020: [EU Trends] and [EURPROG]. By performing this calculation for both data sources, the aforementioned discrepancies between both scenarios partly level out and there is almost no difference between the total new power plant capacity needs between the two scenarios. The remaining discrepancies concern different assessments for individual countries (particularly for Italy and Poland) as well as differences regarding the role of various power plant technologies by fuel type. [EURPROG] in particular indicates higher investment needs for natural gas-fired power plants and for fossil fuel-fired power plants, whereas [EU Trends] generally favours higher contributions of renewable technologies, particularly biomass and waste power plants but solar power plants as well.

Particularly for [EURPROG], neither the scenario methods nor the basis of expert judgement that impacts the results of the study are transparent. The [EURPROG] Scenario may have been obtained with different approaches and assumptions from the EURELECTRIC members in the various countries. Since [EU Trends] refers to a scenario framework that explicitly includes the latest climate policy measures on EU level but also the mandatory national greenhouse gas emission and energy targets set for 2020, the [EU Trends] Scenario is thus finally applied in this project to determine the requirements for new power plant capacity investments.

This main result regarding the required new power plant capacities up to 2020 is shown in Table 33. In total, a capacity gap of 153.8 GW is determined. It is predicted to be filled mainly by about 50.2 GW wind power investments and about 26.4 GW coal power plant investments. Wind power capacity additions have its focus on the two Mediterranean countries Italy and Spain, whereas investments in new coal-fired power plants are particularly high in Poland.

Apart from these two power plant technologies (wind power and coal power plants), further significant market shares for new power plant construction are predicted for hydropower (16.3 GW, with the largest shares in the two Mediterranean countries) and biomass and waste power plants (1.6 GW, with significant shares in Italy and Finland). Required new capacities for nuclear energy, solar power and natural gas-fired power plants all amount to about 12 GW. New solar power capacities will be concentrated in the Mediterranean countries and new natural gas power plants in South East European countries, particularly in Greece and Romania. New nuclear power plants are specifically required in the North East European countries, but also in the Mediterranean countries.

As a general trend, power plant investments in North East European countries will be dominated by coal power plants, in Mediterranean countries by wind power plants and in South East European countries, in addition to these two technologies, natural gas-fired power plants will play a major role. 54% of new power plant capacities of the selected EU countries are required in the two Mediterranean countries, 24% in the six North East European countries and 22% in the five South East European countries. The Mediterranean countries Italy and Spain are not only the countries with the highest identified capacity gaps in absolute terms, they are also the only net electricity importing country cluster that is going to keep its importing status, at least until 2020. As such, the Mediterranean countries are preferred candidates for electricity imports from outside the EU. But as the analysis has shown, generally all countries promise considerable potential for new power plant capacity investments up to 2020.

4. The Decision Making Model

For setting up the decision making model, first the electricity markets in the EU generally are characterised (section 4.1), as they form the background for the investment decision. Then each decision factor that influences the investment decision for new power plants is discussed (section 4.2). In this section it is also explained how the decision factors are integrated into the model. In section 4.3 the model itself is introduced.

4.1 Characteristics of Electricity Markets and Electricity Price Settings

Electricity markets determine the revenues of power plants. Features of electricity markets can thus crucially impact investment decisions for new power plants.

The European electricity market is undergoing a fundamental long term change that is mainly driven by two factors: On the one hand the ongoing liberalisation and trans-European market integration and, on the other, hand the integration of renewable energies and associated decentralisation.

Liberalisation was first introduced by an EC directive [96/92/EC] into European markets and has since been continuously strengthened on EU level. The aim is to create the framework for maximum competition and free trade for grid-bound electricity. Elements of this concept are:

- free choice of consumers to choose their electricity suppliers
- non-discriminating grid access for suppliers
- unbundling of generation, grid, trade and sales.

Since transmission and distribution of electricity tend to form natural monopolies, regulatory authorities are perceived as necessary to secure fairness and competition. Independent network system operators are responsible for smooth grid operation. They manage voltage and frequency control as well as any deviations from network schedules and from the usual system operation modes.

European electricity markets can be separated into wholesale markets and retail markets. Generators sell electricity on the wholesale electricity markets. This trade occurs on the extra high voltage (EHV) level that is usually the 380 kV grid. The price paid by the final consumers includes several other price elements, like use-of-system charges, taxes etc. which cannot be influenced by the generators. Hence, the relevant price for generators is that on the 380 kV level. But retail pricing, too, is outlined below although this is a minor influence when taking decisions on new power plants.

Participants in the wholesale markets undertake various functions, including bidding (purchasers), offering (generators), scheduling and dispatch (system operator), pricing (pricing manager) and clearing and settlement (clearing manager). Although large consumers can take part directly in the wholesale electricity markets, households and smaller consumers are usually supplied by retailers and distribution companies that purchase electricity on the wholesale market. The retail component of the market is made up of a number of complex processes that address accuracy of metering, meter reading, switching of consumers, and allocation of volumes of electricity to trading.

Trading on wholesale markets occurs in spot markets, at power exchanges and over-the-counter (OTC). Power exchanges are third parties that facilitate transactions of defined electricity products between sellers and buyers. Spot markets provide a trading platform for short term horizons, mainly day-ahead and intraday markets. The spot market closes a few hours before the actual physical delivery of the electricity. System operators use real-time markets to balance generation against consumption within very short time periods. Additionally, ancillary services are required to support reliable delivery of electricity and these are sometimes also traded on power exchanges. Power exchanges offer an anonymous market for electricity trading. Additionally, bilateral contracts can be arranged, either via power exchanges or separately. They often have a very long time horizon and limit the price and volume risks of power plant operators as well as of large consumers (price and volume risk hedging). A successful financing strategy for an investment in a new power plant often requires that large electricity volumes to be produced over the lifetime of the power plant are contracted at a profitable price even already before a decision is taken on the investment.

The costs of system operation are passed on to the consumer, depending on the grid voltage level at which the consumer withdraws electricity. The costs of the highest voltage are passed on to lower voltage levels and distributed equally to all consumers of the same level. The retail prices that consumers face are thus quite different from those prices that electricity generators can obtain on the wholesale market. Also taxes or further components of the retail electricity price have no direct impact on the revenues of the generator.

Although efforts to develop affordable electricity storage technologies have intensified in recent years, electricity is still a commodity that cannot be stored efficiently, at least not at the final consumer. Thus electricity is supplied to consumers when it is generated and the transmission system must be in balance in real time. Electricity demand varies as a function of season, day of the week and hour of the day. Wholesale electricity markets organise time-focused and location-focused matching of demand with supply at fluctuating market clearing prices.

Zonal pricing is a distinctive feature of European electricity markets, based on discrete transmission zones called control areas. The transmission system of each such area is operated and controlled by just one transmission system operator (TSO). For all EU countries investigated in this study, the control areas are congruent with the national territories. What they have in common is that no differentiation is made between the location of injected power nor are there any limits on the power that could contractually be injected into a given node of the network [KU Leuven]. The internal grid of a control area is supposed to be strong enough to cope with any scenario of internal dispatch. Rare cases of technical infeasibilities are resolved by the TSO and its costs are charged to the users of the domestic electrical system via the transmission tariffs. This model has been adopted to preclude discrimination between network users. The internal grid of each zone must be capable of handling all possible internal dispatch scenarios, or costs of rescheduling generation units to achieve a feasible dispatch within an acceptable range.

Congestion across zones is relieved by charging different zonal prices. Also congestion within the zones must be handled and is arranged by the TSOs with a redispatch process.

In Nord Pool, separate balancing markets are used to manage and price congestion [CIFE]. Sweden and Finland use ‘countertrade’ principles in which the system operator pays for power that would be competitively generated in an area but is constrained by transmission congestion. It also pays the additional amount for electricity that would normally not be competitive but needs to be brought on line to relieve congestion. The system operator recovers the revenue through system-wide transmission charges. In Norway, prices are lowered in surplus areas and raised in deficit areas until congestion is relieved. Whatever costs that the system operator incurs are recovered in a market settlement process among all market participants.

For as much operation time as possible, profitable power plants must seek to be ‘in the money’. The term ‘in the money’ characterises situations when the variable operation costs of the plant are below the achievable market prices, thus attaining profitable operation in the short term. Consequently, auctions at Power Exchanges are organised according to the so-called merit-order principle.

According to this principle, market agents submit their bids, specifying the quantity and the price they are willing to sell/buy, with no knowledge of other bids. All bids are sorted in an ascending ordering of price and are aggregated to a market demand and supply curve (see Figure 70). Intersection of the supply and the demand curve yields the market clearing price and the market clearing volume. All volumes up to the market clearing volume are transferred at the same market clearing price from all sellers that have bid at a price equal or lower to the market clearing price to all buyers that have bid at a price higher or equal to the market clearing price.

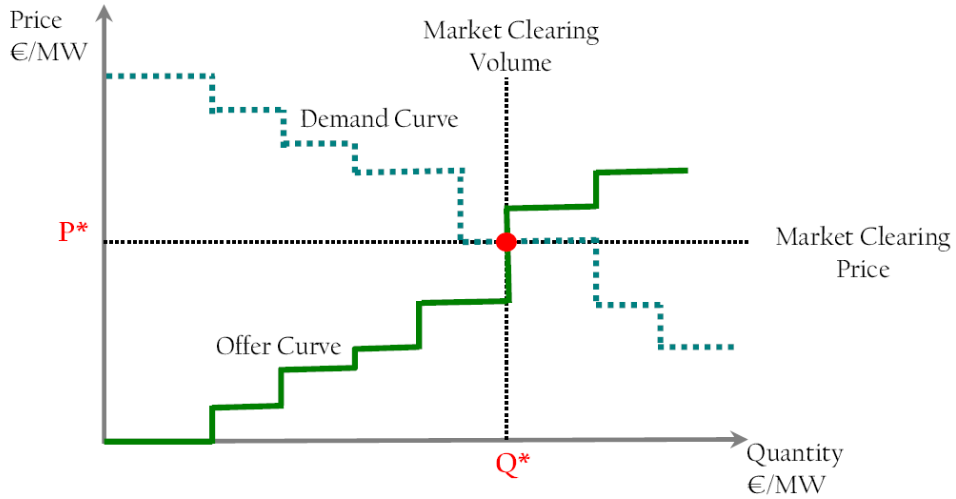


Figure 70: Market clearing at power exchange auction (from [UPC])

The merit order curve of a country is an ascending ordering of the available installed capacity in the system, based on the marginal cost of generation (€/MWh) for each unit supplying the system. Examples of the merit order curve in Spain for some years in the past are shown in Figure 71.

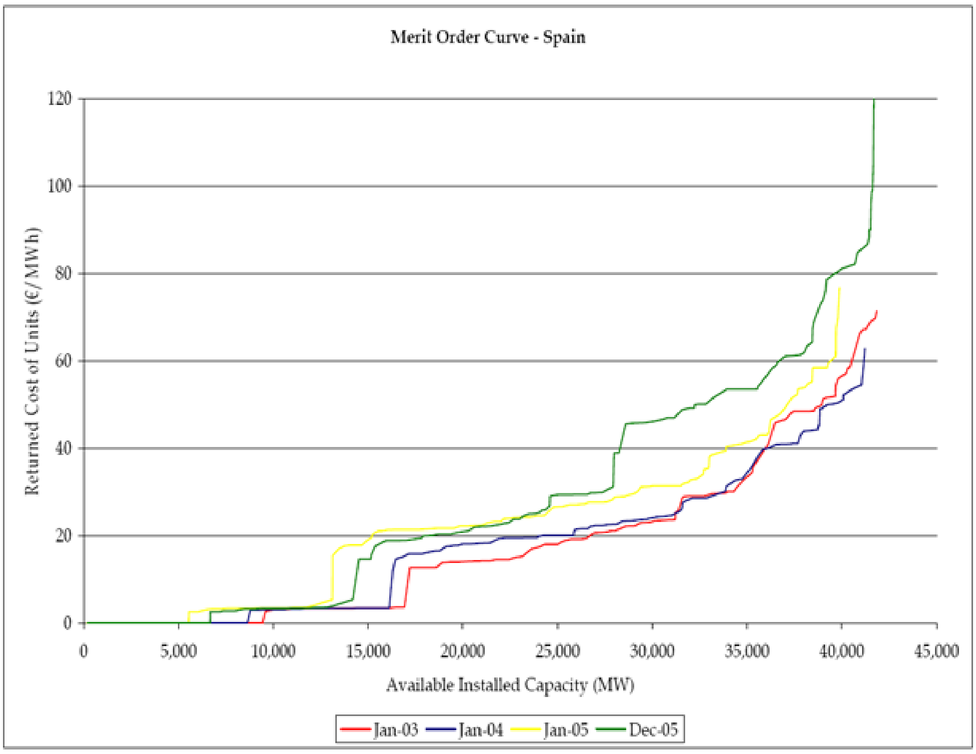


Figure 71: Merit order curves for Spain from 2003 to 2005 (from [LE])

Generators who are interested in selling their electricity production may submit their offer based on sellers expecting that the market clearing price will be higher. But over the long term, the remaining difference between market prices and marginal costs must cover also their fixed costs, including capital costs and fixed O&M costs. Fixed costs arise solely from making the power plant available, independently of its operation. Fixed costs include particularly capital expenditures (CAPEX), annualised over the life time.

Power plants should run ‘in the money’ for as many operational hours as possible during a year to quickly pay back its capital costs. Due to typical intraday load profiles, though, some power plants are required and dedicated to covering only additional peak load demand during some intraday periods, mainly around noon. Due to their low annual operational time, peak load power plants should not absorb high capital costs that would result in excessive payback times. Instead, their profitable operation during their few operational hours requires compensation by increased peak load prices.

Accordingly, wholesale electricity markets in Europe are segmented into base load and peak load periods. This is reflected at the power exchanges with different electricity products for base and peak load.

The physical nature of electricity does not allow for a true electricity spot market with immediate electricity delivery. Instead transactions are scheduled in advance of physical delivery. Buyers must provide their demand profile for the day ahead in 15 minutes time intervals, usually at 14:00 of the day before physical delivery. On the forward markets also electricity for delivery in months, quarters or years ahead can be traded.

The rising integration of renewable energy shares in the European electricity generating mix will bring about major changes for the whole market and impact all market players. The fluctuating wind and solar power supply will very probably increase price volatility on the markets. This means increasing price risks for power plant investors that can hardly be estimated in advance of taking an investment decision. Even the role of peak load and base load power plants may change fundamentally and in an unpredictable way. For instance, high solar power availability around noon may generally decrease peak prices. Furthermore, carbon dioxide (CO_2) emission certificate prices may reduce the number of operating coal power plants, leading to a scarcity of base load power and to higher base load prices.

Additionally, another very crucial uncertainty for power plant investors regards the operating hours that will remain for conventional power plants in a future market with high renewable shares. This question addresses also the market design, i.e. to which extent renewable electricity generation will have to be absorbed fully at any time by the market and whether there will be a market premium just for providing excess power plant capacities that balance fluctuating generation from renewables. The existing merit-order principle based on marginal (short term) costs may turn out not to work properly in such markets and currently it is not clear what kind of market design may follow. A return to pricing methods that were prevailing before liberalisation and are still applied for use of system tariffs may be considered as a likely scenario: Pricing based on a capacity price and an energy price, instead of a flat kWh price.

Furthermore, integration of renewable energies requires an almost completely different grid system design. The grid must become capable of connecting many decentralised facilities, of transmitting large volumes of fluctuating renewable energies over long distances within Europe and it must integrate demand-control features (smart grids), especially for system stability reasons. In the European network controlled by the European Network of Transmission System Operators for Electricity (ENTSO-E), the TSOs are responsible for grid stability. This means that new power plants to be connected have to demonstrate to the grid operator that the grid code will be complied with and system stability will not be put at risk due to the new generation capacity. In case of noncompliance, the TSO concerned could reject the grid access for a new power plant.

4.2 Investment Decision Factors

4.2.1 Economic decision factors for investment

4.2.1.1 Fuel prices

The price development of fossil fuels is of great importance for power plant investment. The predominant primary energy sources for electricity generation are lignite, coal and natural gas. Crude oil and its products, heavy and light fuel oil, play only a minor role for electricity generation. However, crude oil is still and will remain for the foreseeable future the price leader in the fuel market. The prices of all other fuels follow the price fluctuation of crude oil (see Figure 72). The price of imported natural gas is directly linked to the crude oil price in purchase contracts. Changes in fuel prices directly affect investment decisions for power plants since increased fuel prices raise the variable operating costs of a power plant.

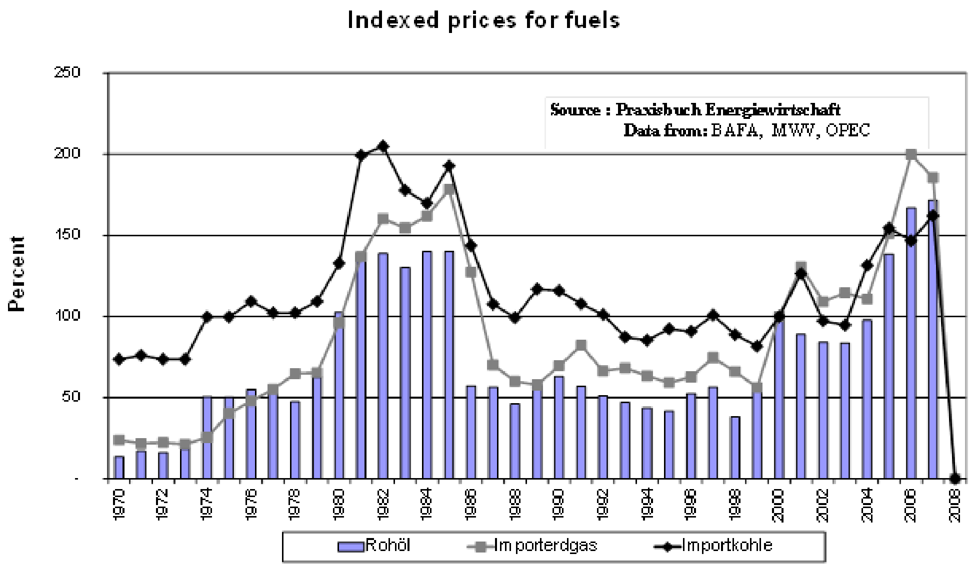


Figure 72: Indexed fossil fuel prices

The procurement options for primary energy sources differ greatly. For example, to generate electricity from lignite in a specific country, the power plant has to be close to the deposits of this energy source. This means that lignite has no global market and there is no price uncertainty for power plant operators regarding lignite prices.

Hard coal, however, competes with internationally traded hard coal that is transported to the power plants. In this case, power plant operators are bound to world market prices and they are exposed to price volatilities. As a consequence, coal is mostly procured through long-term supply contracts for defined fuel volumes at defined prices. This leads to a certain hedge against fuel price volatility although the contracts include also a clause for price indexation depending on the crude oil price. Imported coal for Central European countries is shipped from oversees to the ARA harbours (Amsterdam, Rotterdam, Antwerp). Statistics for CIF prices (incl. cost, insurance, freight) of hard coal are available. It must be noted, however, that the CIF prices also include the freight rates for overseas shipment, which are extremely volatile and often amount to half of the coal CIF price (cf. Figure 73). Hence, countries with indigenous coal resources, like Poland, have a distinct price advantage. Also the storability of coal can uncouple the procurement of coal and its use for electricity generation to some extent.

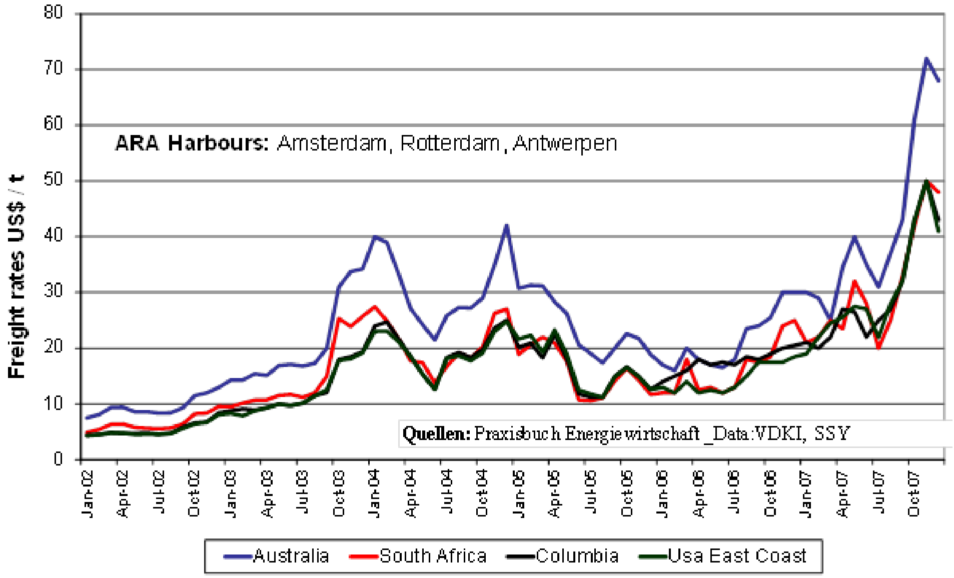


Figure 73: Freight rates for coal

Natural gas prices have similar characteristics to electricity prices (cf. section 4.2.1.5 below). Because of short-term trading transactions for natural gas, these prices have higher volatility and price spikes compared to coal. They also exhibit, alongside the use of natural gas for electricity generation, a seasonal behaviour because of its use for heating.

Another issue is the long-term availability of fossil fuels. Their increasing scarcity may result in fuel price increases. Projections for the long term availability of crude oil are hard to predict and the development of the crude oil market in the future is very uncertain, with significant pricing pressure also on the natural gas and coal markets. Reserve-to-production ratios for coal and lignite are currently at around 150 years. This indicates that at least there will be no short-term supply shortages on the coal market, even in the event of rising coal demand on electricity markets.

Uncertainty regarding the development of fuel prices results in imprecise planning criteria for power utilities. An increasing demand for gas due to European CO_2 emissions trading is another market risk. Similarly, rising electricity demand can boost fuel prices. Uncertainty regarding fuel prices is considered in the decision making model through three different scenarios as described in more detail in section 5.1.2.

4.2.1.2 Prices for CO_2 allowances

As with fuel prices, likewise the price for CO_2 allowances has to be considered as an uncertainty when generating electricity in thermal power plants. EU allowances (EUAs) for CO_2 have been traded since the adoption of European CO_2 emissions trading on the future and spot markets of electricity stock exchanges in EU countries. For each trading day, electricity stock exchanges publish a reference price per tonne for the Europe-wide trading of EUAs.

To determine the prices of CO_2 allowances, the fixed reduction target is relevant. The costs of CO_2 abatement as well as the demand for emission allowances are higher the stricter the target. In future, this may lead to rising prices for CO_2 allowances and the variable costs of emission-intensive power generation technologies may be forced up. On the other hand, a possible shortage of CO_2 allowances would have the effect of pushing up CO_2 prices, leading to a change in the competitive relationships in the electricity generation sector. A surge in demand for natural gas due to its lower CO_2 content compared to coal cannot be excluded because coal-fired power plants are and will remain responsible for most of the CO_2 emissions in the energy sector.

Since the inception of CO_2 trading, each ton of emitted CO_2 has acquired a market value. This is independent of whether emission rights have to be bought on the market or are allocated gratis. Accordingly, power utilities in the EU have included the CO_2 market value in their actions and calculations. It is only to be expected that, since the adoption of CO_2 emissions trading, this market value has also been factored into electricity prices.

With full auctioning of CO_2 allowances in the 3rd trading period starting in 2013, energy utilities have to purchase all their CO_2 allowances. This will turn windfall profits from allocated CO_2 emission rights into operative costs and will thus more directly assign a carbon burden to the competing power technologies. It is expected that the market value of CO_2 is already fully taken into account in the electricity market, which is why an increase in electricity prices is not expected due to the change to full auctioning.

Nevertheless, the actual level of ETS prices does impact electricity prices. The interlinkage of prices for fuel, CO_2 allowances and electricity has to be considered under the aspect of uncertainty. The price trend for CO_2 allowances and the resulting costs for power plant projects remain unsure, leading to uncertainty among potential investors. Given the long lifetime of power plants it is important that reduction targets are set far into the future to assess the development of costs for CO_2 allowances. In the decision making model, the uncertainty of prices for CO_2 allowances is taken into account by analyzing scenarios for different CO_2 price developments (see section 5.1.1)

4.2.1.3 Electricity demand

Electricity demand is of particular interest for the future electricity market and hence for investments in power plants. The total demand as well as the peak load demand change over the years and have an impact on electricity prices and therefore on the profitability of new investments. Development of electricity demand is influenced by various factors:

- population development
- overall economic development
- development of the sectoral structures of the economy
- development of electricity prices (partly subject to environmental policy requirements)
- development of specific consumption of electrical appliances (for example energy efficiency and lifetime of electrical appliances)
- development of energy consuming equipment and its use
- development of coverage of new electrical appliances
- development of energy efficiency standards for new equipment.

From the viewpoint of the power plant investor, the anticipated electricity demand is reflected in expectations regarding future electricity prices. But the constraints and conditions for electricity demand and prices have no bearing on the decision on whether to install the new power plant inside or outside the EU. The reason is that in both cases the power plant will supply the same market in the EU country concerned. In general, the investor will seek to reduce demand risk by selling a preferably large part of future electricity generation before even taking the investment decision, via bilateral contracts with customers.

4.2.1.4 Prices of power plants and availability of labour and capital

In recent years, prices for power plants have risen rapidly. The reasons are the high demand for new power plants to replace aging ones, the increase in prices for materials such as steel and copper, and the additional cost of measures to improve efficiency. Ten years ago, steel prices were still about 300 €/t. In 2011, they attained a price of about 600 €/t. The price trend for copper is somewhat similar. The energy efficiency of power plants has to be increased steadily due to high primary energy prices and costs for CO_2

allowances. Therefore, new steam power plants, for example, are designed for ultra-super critical (USC) steam conditions (260 bar/620°C). But this requires high temperature-resistant materials that are costlier and increase construction costs. Boiler manufactures try to compensate for the cost increase by exploiting economies of scale with larger power plant units, which has the effect of lowering specific investment costs the larger the power plant.

If demand for power plants increases as expected over the next few years, due to new and replacement investments, this will have a considerable impact on investment decisions. The construction costs for coal-fired power plants with USC conditions rated at 800 MW are in the order of about 2000 €/kW. The specific costs of gas-fired combined cycle gas turbine (CCGT) power plants are in a range of about 700 €/kW. The actual costs of power plants depend on the current market situation and on free capacities of providers as well as on pricing aspects of the manufacturers of power plant components. Also local aspects (labour costs for workers) may be relevant. Furthermore, uncertainties about future exchange rates can have an impact on the investment costs if power plant components are obtained from outside the EU. As investors act internationally with global investment activities in different countries, they can limit currency risks through hedging short-term transactions in major currencies in the foreign currency forward or future market. For longer periods, it is possible to hedge with a series of long-dated forward contracts or with a currency swap. Since hedging against currency risks is manageable for an international investor, it is not explicitly considered in the decision making model.

The costs for power plant hardware are considered in the decision-making model as specific power plant costs in Euros per kilowatt. These prices are fixed for different types of power plants because investors will choose their EPC contractors (Engineering Procurement and Construction) regardless of the country where the power plant is built. However, prices for construction works are considered through specific manpower costs in the respective countries. The same applies to working staff during the operation period. Accordingly, these aspects are factored into the decision-making model.

4.2.1.5 Electricity prices

Today, electrical energy can neither be stored directly nor be substituted by other energy sources to any great extent, so supply must balance demand in the national grid at all times. This results in short-term inelastic electricity demand and in highly fluctuating electricity prices which is expressed by their volatility. In particular, a seasonal variation is observed: in northern Europe, electricity prices are higher in winter due to the usually higher level of demand in this season. In addition, electricity prices also exhibit characteristic daily and weekly patterns in the spot market. The high volatility and the occurrence of extreme price spikes are among the stochastic characteristics of electricity prices, referred to as the mean-reversion process. Mean-reversion describes the tendency of electricity prices to return to their long-term average after fluctuations.

The wholesale price of electricity is established on the future and spot markets of electricity stock exchanges of individual EU countries. Forward contracts at these stock exchanges provide an opportunity to hedge against price uncertainties in advance. Price volatility can be reduced and only little mean-reversion can be achieved.

Overall, the introduction of wholesale markets leads to an increased competitive situation for individual power plants themselves. Since electricity prices vary greatly, the financial returns of power plants are subject to high uncertainty. Revenues from the electricity prices are the primary income source of power utilities which have to recover all their costs with these. Thus, covering the full costs of electricity generation by electricity prices is a fundamental prerequisite for long-term investments in power plants.

In general, consumers may buy electricity either at the power exchange or over the counter with bilateral contracts with power generators or suppliers. Buying electricity from the power exchange may bring advantages. However, it might be a risky undertaking due to volume and price risks. Optimised procurement of electricity is achieved with a portfolio management by combining several products of the market as shown in the figure below. This approach is usually taken by large consumers and traders.

The same approach will be applied by potential investors of new power plants, especially for projects outside the EU. They will try to secure the bulk of their production with bilateral contracts with large consumers and traders of electricity with portfolio management in order to mitigate risk caused by price volatility on the power exchange (see Figure 74). This will also be a security requirement for loans from banks, which usually finance the major part of the capital expenditure for new power plants.

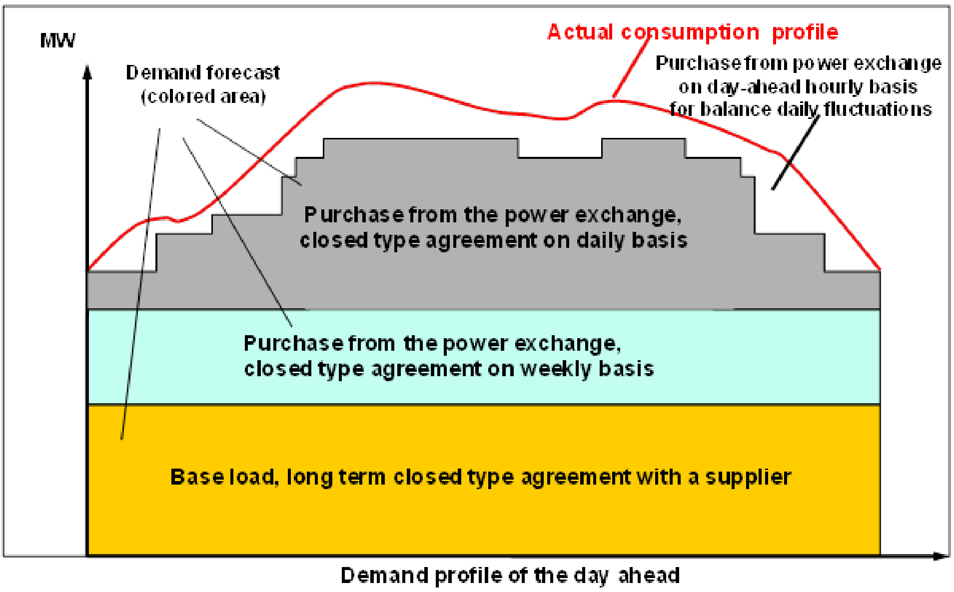


Figure 74: Example of portfolio management

Competing power plants inside and outside the EU will supply their generated electricity to the same EU market. As the prices are volatile, and predictions are practically impossible, the plant with the lower electricity generation costs will have a competitive advantage. Therefore it is sufficient to compare only the relevant electricity generation costs of the power plants.

4.2.1.6 Taxes

Taxes relevant for power plant investors are corporate tax and fuel taxation. In general, these tax rates could differ between all the countries considered. For EU countries, though, fuel taxation has been harmonized. According to the Council Directive [2003/96/EC], EU member states are exempted from taxation on energy products used to produce electricity, i.e. on fuel taxes for power generation. However, outside the EU, additional taxes on hard coal, lignite and natural gas may be in place for power plant operators.

Electricity taxation is not dependent on the country of power plant installation but rather on the country where electricity is consumed, which in our investment analysis is always the EU country of each EU/non-EU country pair under consideration. Thus electricity taxes do not result in any discrimination of investments outside or inside the EU. Electricity taxes have no direct impact on wholesale electricity prices which determine the revenues for the power plant operator. Electricity taxes are therefore not further taken into account in this study.

Corporate taxes affect the rate of return, in particular the rate of return on equity (ROE). A project must provide a certain pre-tax return to satisfy the expected after-tax return on ROE. Therefore, corporate taxes influence the discount rate to be applied in the decision making model. Since corporate tax rates vary considerably by country, the discount rates applied in the decision making model generally differ for each country. Taxation conditions could change over time, posing a risk to investors that must be covered by the expected rate of return on investment. Uncertainty regarding tax rates can be taken into account in the model by conducting sensitivity analyses in cases where the current rate seems to be very low.

4.2.1.7 Financial risks from financing the investment

There were sharp drops in both electricity demand and prices at the start of the financial crisis in 2008 while credit conditions for power plant projects became more stringent as the creditors required a considerably higher equity portion on the CAPEX. This resulted in a loss of attractiveness for investments in such plants. There was thus an incentive to keep older, depreciated plants running and to postpone investments in new ones, despite the poor efficiency of the aging plants.

Also impacted was the profitability of renewable energies during the economic crisis. Due to their high capital cost and falling fuel prices, they were put in a worse position by the economic crisis vis-à-vis conventional electricity generation technologies. The energy sector, however, is far less exposed to fluctuations in sales than other industries due to electricity demand elasticity being generally low. Thus, the risk assessment by investors may be lower.

Generally there are always funding risks, so the capital needed for a project may not be available. For example, equity participants might fail to contribute their determined amount or it may not be possible to raise the target amount in the market. Another funding risk is re-financing, which occurs if the period of initial funding does not match the duration of the project. As funding is an essential part of project financing, it is sometimes difficult to reduce the risk of not finding funding. The option of seeking capital from a broad range of sources is a way of mitigating this risk. In addition to funding risk, interest rate fluctuations present a significant risk for highly-leveraged power plant financing arrangements. Arranging for long-term financing at fixed rates mitigates the risk inherent in floating rates. Furthermore, investors can enter into interest rate swaps to hedge against interest fluctuations.

Loans for power plant projects have usually a debt maturity of about 15 years with a fixed interest rate. There is usually no need for prolongation of the loan.

4.2.2 Non-tangible decision factors

The main non-tangible decision factors are for instance:

- risks related to the longevity of this investment
- associated technology innovation risks
- political risks
- non-acceptance by the public
- plant availability.

Some of these factors can be taken into account in monetary terms via a risk premium. Others can only be assessed through sensitivity or risk analyses. The factors are discussed in the following.

4.2.2.1 Longevity of the project and associated technological risks

Power plant projects are designed for a life of 35 years based on prevailing or foreseeable market conditions. Throughout this period, the invested capital is tied up in the project. Changes in market conditions may adversely impact the project’s profitability. Over the past thirty years, for instance, emission standards have become more stringent, the electricity market has been deregulated and carbon emissions have turned into a cost factor.

These types of risks are addressed in the decision-making model with a ‘venture premium’ on the return on equity. The usual magnitude of venture premiums for a power generation project is in the range of the risk-free rate of return. For details see section 4.2.4.

4.2.2.2 Technology development

Power plants projects are designed to the state-of-the-art prevailing at the time and built for a life of 35 years. Throughout this period, the invested capital is tied up in the project but technological innovations may have an adverse impact on the project's profitability.

Power plant technologies are continuously improving, especially for renewable energies, but also for thermal power plants. Further increases of efficiency factors, cost reduction, pollutant abatement and progress on safety aspects are expected. Coal-fired power plants with modern technology, for example, are able to reduce CO_2 emissions by 2.4 million tonnes per year and fuel costs by 2.4% with only one%age point higher efficiency. Supercritical coal-fired power plants are already state of the art. Electricity generation costs, the development of electricity prices and the political framework are other drivers for technological advancement. The initial focus was on increasing the installed capacity. But to reduce greenhouse gas emissions, improved fuel efficiency and thus a rise in the efficiency factor of thermal power plants are objectives.

Nevertheless, the race of technologies for fastest development and highest efficiencies presents a problem. At the time of an investment, it is possible that other technologies will get ahead. Since investments in power plants are long term, once spent, capital is locked in, resulting in sunk costs for the investor. The potential benefits of new technologies may finally imply lower electricity prices.

4.2.2.3 Power plant unavailability

For thermal power plants, there are two reasons for their non-availability. For inspections and repair works power plants have to be shut down so they are not always available. Usually this is done during off-peak times and the outage can be estimated quite well. That is rerffered to as 'planned non-availability'. On the other hand there can also be unscheduled, forced power plant outages. These result in a sudden shortfall in supply and a change of market price. Accidents, fires or other failures lead to unscheduled power plant outages. These are always subject to uncertainty. In addition, the probability of an outage depends on the age, size and type of the power plant. For example, by replacing older components with improved components both availability and lifetime are optimised.

Statistics are compiled on power plant availability (e.g. Analysis of unavailability of thermal power plants – [VGB TW]). These are taken into account in the decision making model by assuming equivalent operation hours (EOH) for the various plants types. EOH are defined approximately as hours of the year minus hours of non-availability.

4.2.2.4 Investment security and political risks due to plant location

Depending on the location there might be country-specific risks, examples of which include civil unrest, guerrilla sabotage of projects, work stoppages, any other form of force majeure, exchange controls, monetary policy, inflationary conditions, corruption, political encroachment, etc. The country risk serves as the ceiling for a project's risk rating. For an example, credit rating agencies place ceilings on specific project ratings through the sovereign credit rating that the agency assigns to the country. This means that no project can have a higher credit rating than that of the country concerned. Specific mitigation might include political risk insurance against force majeure events or allocating risk to local companies.

Political risks on the other hand are sometimes the ones of most significance faced by investors because of the likelihood of sudden political change, which can jeopardise projects at a critical stage. Such risks include changes of a country's political landscape, like change of administration, as well as changes in national policies and regulatory frameworks. Power plant schemes, especially in developing countries, continue to face significant risks, albeit in more subtle forms like price regulation, restrictions on work permits for foreign managers, renegotiation of contracts and even buyouts.

Political risks are covered in the decision-making model through a 'country-specific risk premium' added to the risk-free rate of return on equity (ROE), as described in more detail in section 4.2.4. The risk premium thus depends on the country in which the investment is made.

4.2.2.5 Public resistance or acceptance

Construction projects of conventional power plants often experience considerable public resistance. The acceptance for any new power plant has decreased in industrial countries. Citizens' protests may even result in stopping a power plant project completely. Public resistance or acceptance may differ in the countries considered and may therefore impact the decision on power plant location. When decisions are taken on investments in power plants, the aspect of public resistance or acceptance is considered in the same way as country-specific risks and political risks (4.2.4.). The investor will adapt the risk premium to mitigate the risk.

4.2.3 Appraisal of capital investment under uncertainty

Investment risks can also be managed partly by applying hedging strategies (see 4.2.5), but any remaining risks have to be absorbed by an adequate appraisal of the risks of capital investment. This is reflected in the expectations on return on investment. From a portfolio of risky investments, the expected returns are adjusted upwards to an amount that would cover expected losses due to possible defaults of some of the investments in the portfolio. Formally, this is implemented via the risk premium put on top of the expectations on return from a risk-less investment. The risk premium is the incentive necessary for allocation of capital to more risky investments rather than just investing in less risky ventures.

Apart from hedging and the risk premium approach, a third way of risk assessment is sensitivity/scenario analysis. Whereas the risk premium incorporates the expectancy value of the risk, the remaining risk attributable to the spread around the expectancy could be covered by scenario analysis. This is usually done by deriving not only a most expected scenario but also a best case and a worst case scenario for the investment. Applying the above described investment appraisal approach for different scenarios will give the investor a picture of the range of potential future developments. Usually, real investment behaviour tends to be risk averse, i.e. a more risk avoiding investment is favoured compared to a more promising but risky investment. Thus an investor would like the investment to yield a minimum expected return even in the worst case scenario.

In a scenario, a consistent combination of variables is analysed. In our case of power plant investment appraisal, such a set of variables that make up a self-contained scenario includes fuel price paths and emissions trading scheme price paths, since these correlate with each other (see section 5.1). Thus the scenarios defined and analysed with the model contain dedicated assumptions for the future CO_2 price and fuel price developments (in real terms).

Sensitivity analysis is a subset of scenario analysis where the effect of specific variables on the return is analysed. Sensitivity analysis would mean studying, for instance, the variation of the expected inflation rate on the outcome of the investment appraisal. Both methods – scenario analysis and sensitivity analysis – may be applied using the decision making model to test the robustness of the investment appraisals.

4.2.4 Usual level of return on investment - weighted average costs of capital

Investments for power plants are usually financed by a combination of own capital of the investors (equity) and bank loans. Accordingly, the expected return on investment (ROI) is a weighted average of the return on equity and the interest on the bank loans. As such, the ROI defines the imputed costs of capital for the total investment, called weighted average costs of capital (WACC). Banks usually require an equity share of about 30% of the capital expenditures for power plant projects while 70% is covered by loans from bank consortiums. The interest rate for long term bank loans within the EU can be considered as quite stable in the range of about 5% to 6% in nominal terms or about 3%age points in real terms (on top of inflation). It can be further assumed that, due to the magnitude of the investments that are of an order of a billion or billions of Euros, only financially strong investors will be able to invest, who will have access to and possess credibility in the financial market. Hence, favourable conditions for bank credits can be achieved by such investors also for projects in neighbouring EU countries.

Table 36 below shows typical conditions for WACC for power plant projects. We are of the opinion that the crucial factor for the investor is the return on equity (ROE) he is expecting from the project. The return on equity can be broken down into four components:

- The *risk-free rate of return* can be assumed as equal to the bank interest rate.
- The *venture premium* is typical for power plant projects, considering the risks of a long-term investment and related technology risks. This is also in the range of the risk-free rate of return.
- The *country-specific risk premium* considers the economic and political situation in each country.
- Also to be factored in is the *corporate tax rate*.

It is noted that the WACC is used in the investment appraisal as discount rate.

Item	Equity	Loan	Comments
Asset shares	30%	70%	Typical conditions
Rates in nominal terms after tax			
Risk free rate of return	*6.0 %/a*	*6.0 %/a*	Typical within EU
Venture premium	*5.0 %/a*	*n.a*	Typical for PP projects
Risk premium	*3.0 %/a*	*n.a.*	Country specific
Cost of capital in nominal terms, after tax	14.0 %/a	6.0 %/a	
WACC after tax	**8.4** %/a		
Corporate tax, nominal	4.7 %/a	*n.a.*	Country specific
Cost of capital in nominal terms, before tax	18.6 %/a	6.0 %/a	
***WACC$_n$* in nominal terms, before tax**	**9.77** %/a		Country specific
./. Expected Inflation rate	2.40 %/a		
***WACC$_r$* inflation adjusted**	**7.20** %/a		Discount rate

Table 36: Example of typical weighted average cost of capital (WACC) of power plant projects

We are of the opinion that the first two components – risk-free return and venture premium – are common within the EU for power plant projects and will not significantly vary. A more challenging task is to define country specific risks. This can be done by identifying the breakeven point of benefits vs. risks as proposed in the model.

4.2.5 Hedging strategies for new power generation plants

Investors and corporations use hedging techniques to reduce their exposure to various risks. Hedging against investment risk means employing strategic instruments in the market to offset the risk of any adverse price movements. The foundations of hedging in the electricity market are the same as for the purely financial market. However, since the market is not as liquid, the contracts being offered are not as extensive.

Futures and forward markets are important hedging instruments in the development of efficient electricity markets. However, financial hedging instruments appear to have a much shorter time horizon than the term of the investment in power plants. This leaves a substantial residual risk to investors. Seeking to hedge short-term electricity price risks, they cannot rely on these markets to help mitigate such risks.

The requirement of investors to hedge against uncertain future electricity prices remains, if financial markets are not a practical tool for hedging against short-term risk and volatile electricity prices. Contract hedges between investors and consumers might provide a more promising basis for hedging the risks associated with developing new power plants. In most countries, though, consumers' interest in signing long-term contracts is very limited. Such long-term arrangements are more in the interest of industrial customers to stabilise their input costs. But as the existence of surplus capacity and relatively low electricity prices have discouraged long-term contracts since liberalisation of the electricity markets, even the larger consumers rely mainly on three-year contracts rather than signing long-term contracts.

For the sake of completeness, organisational hedges are mentioned. For future investments, today's investors pay greater attention to companies with stable revenue flows and a good customer base. Following liberalisation, companies had to restructure to mitigate investment risks. A strategy for companies making a significant investment in electricity generation to hedge against the risk of volatile fuel prices is to acquire companies which trade in fuels in order to hedge fuel cost risks with power generation. Mergers are one mechanism to obtain more stable cash flows as a source of finance for capital-intensive investments. Higher equity financing is a way to cover more risky investments but at higher funding costs.

4.2.6 Technical preconditions and risks

4.2.6.1 Technical concepts for power plants

The following power plant concepts are considered in the study:

- steam power plant fired with lignite, for base load duty
- steam power plant fired with hard coal, for base load duty
- combined cycle gas turbine (CCGT), for base load and for intermediate load duty
- Open cycle gas turbine (GT) for peak load.

The technical concepts of these plants are briefly described below.

Steam power plant
A simplified heat flow diagram of a typical steam power plant is depicted in the figure below. In the table under the diagram, the main technical parameters are indicated of subcritical, supercritical and ultra-supercritical cycle concepts.

The plant's main components are:

- steam generator
- flue gas cleaning system, limestone gypsum
- water-steam cycle
- steam turbine and generator
- condenser cooling system (CCS) with cooling tower
- auxiliary and ancillary systems

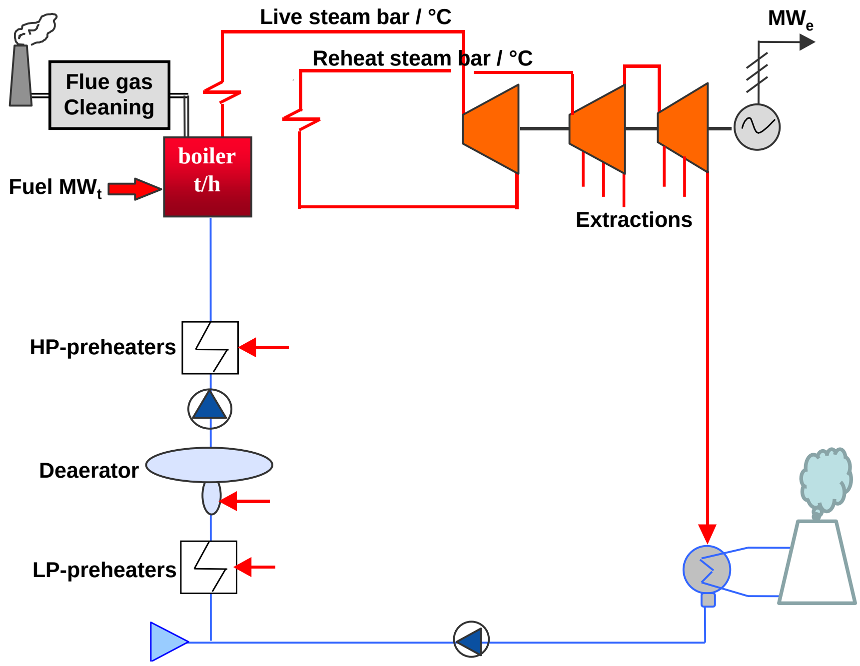


Figure 75: Simplified heat flow diagram of a steam power plant

Item	Unit	Lignite		Hard coal	
Steam conditions	-	SubC	USC	SubC	USC
Live steam	bar / °C	180/535	285 / 600	180/535	285 / 600
Reheat steam	bar / °C	42 / 535	60 / 620	42 / 535	60 / 620
Ratet capacity, gross	MW	900	1100	600	800
own consumption	%	4.50%	4.50%	7.00%	7.40%
Efficiency, net	%	40.00%	43.20%	41.00%	45.60%

Table 37: Typical technical parameters of steam power plants

Subcritical steam power plants are expected to remain the main choice in countries with low fuel prices due to their simplicity, perceived higher reliability, lower investment cost and lower technical risk. However, rising fuel prices and the need for lower carbon emissions triggered by carbon trading schemes have opened opportunities for an increase in the application of supercritical (SC) and ultra-supercritical (USC) steam cycles.

Hence, power plants with ultra-super critical steam parameters will be the base case for EU countries. Furthermore, the plants concepts will allow retrofitting with CCS systems.

Lignite-fired steam power plants are typical base load plants. They are quite inflexible in operation as start-up takes some hours. Due to the high sulphur content of the fuel referred to the calorific value, the cost to acquire carbon certificates is very high.

New hard coal-fired steam power plants will also be operated for base load duty. The costs for carbon certificates are still high.

The availability of steam power plants built to state-of-the-art designs is high. The annual planned outage time for overhauls and maintenance is about 4 to 5 weeks. Forced outages are very rare. Full availability for 7,500 equivalent full load operation hours is guaranteed.

The preparation phase for coal-fired plants, with studies, permit procedures and tendering is estimated as about one year and the actual construction time about four years.

Combined cycle gas turbine power plants
In CCGT power plants, the exhaust heat from the gas turbine at about 500°C is utilised to generate high pressure (HP) steam in a heat recovery steam generator (HRSG), which is then expanded in a steam turbine to generate electricity. The total electrical generation capacity is made up of the contributions from the gas turbine and the steam turbine.

The schematic in Figure 76 shows the configuration of a combined cycle gas turbine plant, comprising a gas turbine with downstream HRSG and a steam turbine. The HRSG can be a single or double pressure design. The HRSG may also be equipped with supplementary firing as shown in the schematic. The gas turbine and the steam turbine each have their own generator. There are also ‘single shaft arrangements’ where the gas turbine, steam turbine and generator are arranged on one common shaft.

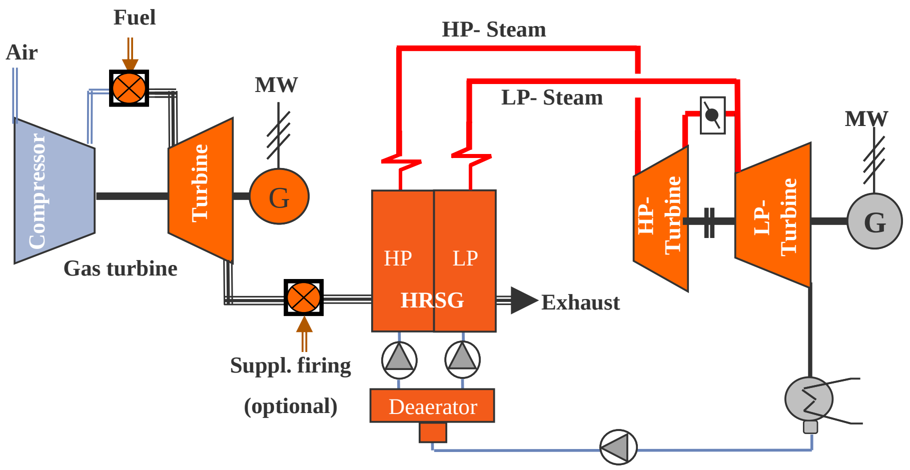


Figure 76: Simplified heat flow diagram of a CCGT power plant

Item	Unit	
Number of units	-	2
Rated capacity per unit	MW	400
own consumption	%	1.50%
Efficiency, net	%	55.30%
Live steam	bar / °C	105 bar / 500°C

Table 38: Main technical parameters of CCGT power plants

The operation mode of CCGT power plants can be base load or intermediate load. They are very flexible in operation as start-up to full load takes less than one hour. This means they will be operated in future for balancing transient grid loadings caused by fluctuations of supply from wind and solar power plants.

This is, though, in itself a substantial risk as planning of their operation time on grid will be hardly predictable. This means they have to cover their costs by providing mainly back-up power.

The output and also the efficiency of CCGT power plants as well as of open cycle turbine power plants depend on the ambient temperature. Part load operation of gas turbines is feasible up to 60% of full load.

As most components for CCGT power plants are prefabricated, the construction time is about two years.

4.2.6.2 Technical concepts for power grids

Generally, the basic structure of a power system relies on synchronous connections between generators which operate all at the same frequency. One of the great achievements of the last century has been the evolution of large synchronous high voltage alternating current (HVAC) power grids, in which all interconnected systems maintain the same precise frequency.

Alongside synchronous interconnection of power systems via HVAC linkage, coupling of different power systems can be done by high voltage direct current (HVDC) connections. HVDC schemes permit asynchronous coupling of power systems, meaning for systems which operate at different frequencies or are otherwise incompatible to allow them to exchange power without requiring the tight coordination of a synchronous network.

4.2.6.2.1 HVAC connections

HVAC transmission technology is the main option for power transfer. The specific costs per kilometre for a typical 400 kV double circuit overhead line (OHL) vary widely from 0.43m €/km to 1.4m €/km, depending on the route and climatic conditions. For this study, the costs of 0.43m €/km has been considered as adequate for general cost assessments of HVAC lines. This covers material and construction costs as well as landowners' compensation payments. Investments in necessary upgrades or extensions of involved local substations are not taken into account and these come on top of the investment costs for new HVAC connections.

4.2.6.2.2 HVDC connections

In principle, there are two types of HVDC connections:

- LCC technology (based on line commutated converters)
- VSC technology (based on voltage source converters).

LCC technology has been developed in the past 50 years, being the classical technology. By taking the present trend in HVDC technology into account, the VSC type is considered as the technology of choice for future projects. Implementation of VSC systems into the existing transmission networks is more uncritical compared to the conventional HVDC technology. A main advantage of VSC over LCC technology is segregated regulation of active and reactive power. Reactive power compensation can support the partially weak networks even if no active power is transmitted via the HVDC system. This could be particularly important for HVDC applications in the Maghreb and Balkan states. Moreover only VSC systems are able to use XLPE cables which are considered as the more sophisticated cable technology vis-á-vis mass impregnated cables. A typical configuration for HVDC systems is a bi-polar configuration. The HVDC voltage is selected dependent on the transmission capacity.

Regarding HVDC interconnection of power systems there are two typical arrangements:

- '***HVDC cable***': Long-distance point-to-point HVDC lines with an HVDC/HVAC converter station at each end of the HVDC line, mostly bi-pole schemes for transmission lines and mono-pole for submarine cable connections; An HVDC cable link can be a feasible option for offshore interconnection.
- '***HVDC b2b***': Both converters in one location without any significant HVDC line in between: this is called an HVDC back-to-back scheme (HVDC b2b). HVDC b2b links are only applicable for onshore interconnections.

These two types of HVDC schemes not only enable the interconnection of asynchronous power systems, but are in some cases also an alternative to usual HVAC links for interconnection of synchronous power systems. One case is linkage over a very long distance of more than about 700 km, which is preferably (i.e. more cheaply) realized with an HVDC connection. For offshore links, HVDC cable links are the technology of choice at already much lower distances (ca. 80 km). The reason is that the usual HVAC cables cannot be used offshore for distances over more than about 80 km.

Costs for HVDC links are typically much higher than for HVAC links. As a result of investigations and analysis of existing projects, the main cost items for HVDC technology are best approximated accordingly:

- converter station costs: 0.22m €/MW
- cable costs: 1m €/km
- cable laying costs: 0.8m €/km.

Investments needed for upgrading existing local AC systems and their capacity for integrating HVDC links are not taken into account in these cost estimates. But all “converter station costs” comprising all components, like switchgear, filters, converters and transformers, are taken into account. Two converter stations per project are required and two XLPE cables per transmission line. As a result of the growing demand for HVDC technology and the high occupancy of cable factories and cable laying ships, prices have risen in recent years. Another cost factor for offshore projects is the depth of the sea and the resulting complexity of cable-laying. This is for instance a particular issue for the very deep Mediterranean Sea and is taken into account in the above cost estimate.

4.2.6.2.3 Interconnection technology of choice

In summary, the type of interconnection – HVAC, HVDC OHL/cable, HVDC b2b – to be used depends on whether the power systems are synchronous or asynchronous, over what distance they are to be linked and via which media (onshore/offshore). In addition, cost efficiency plays an important role. Generally, for each power transmission project, an individual assessment must be made to identify the optimum technology. Nevertheless, Table 39 gives an indication of the usual technology of choice for different configurations of power system interconnection.

<table>
<tr><th rowspan="2">distance of link [km]</th><th colspan="2">link of asynchronous power systems</th><th colspan="2">link of synchronous power systems</th></tr>
<tr><th>onshore</th><th>offshore</th><th>onshore</th><th>offshore</th></tr>
<tr><td>0-80</td><td rowspan="2">HVDC b2b or OHL</td><td>HVDC cable</td><td>HVAC</td><td>HVAC</td></tr>
<tr><td>80-700</td><td>HVDC cable</td><td>HVAC</td><td>HVDC cable</td></tr>
<tr><td>700 and more</td><td>HVDC OHL</td><td>HVDC cable</td><td>HVDC OHL</td><td>HVDC cable</td></tr>
</table>

Table 39: Usually applied technology for interconnection of power systems

4.2.6.2.4 Synchronous zones

There are several synchronous zones involved in the network areas of the countries analysed in this study (see Figure 77). They are introduced in the following. Based on the clustering of the EU countries under investigation, namely North East European countries, South East European countries and Mediterranean countries, also the operational status of the high voltage networks in the different regions is presented.

ENTSO-E RG CE

ENTSO-E Regional Group Continental Europe (ENTSO-E RG CE) is the association of transmission system operators in continental Europe (formerly UCTE, see Figure 77). The ENTSO-E RG CE is the largest interconnected system in Europe. The Continental European interconnected system was designed in order to implement principles of solidarity and economy and was developed progressively starting from the interconnection of Austria, Belgium, Germany, Switzerland, France, Italy, Luxembourg and Netherlands in the 50s.

The system has developed into the present highly meshed network that provides transmission corridors for electricity from generation in-feeds to points of consumption, and allows acquisition of power from neighbouring control areas from the available reserves of partners to make good capacity shortfalls.

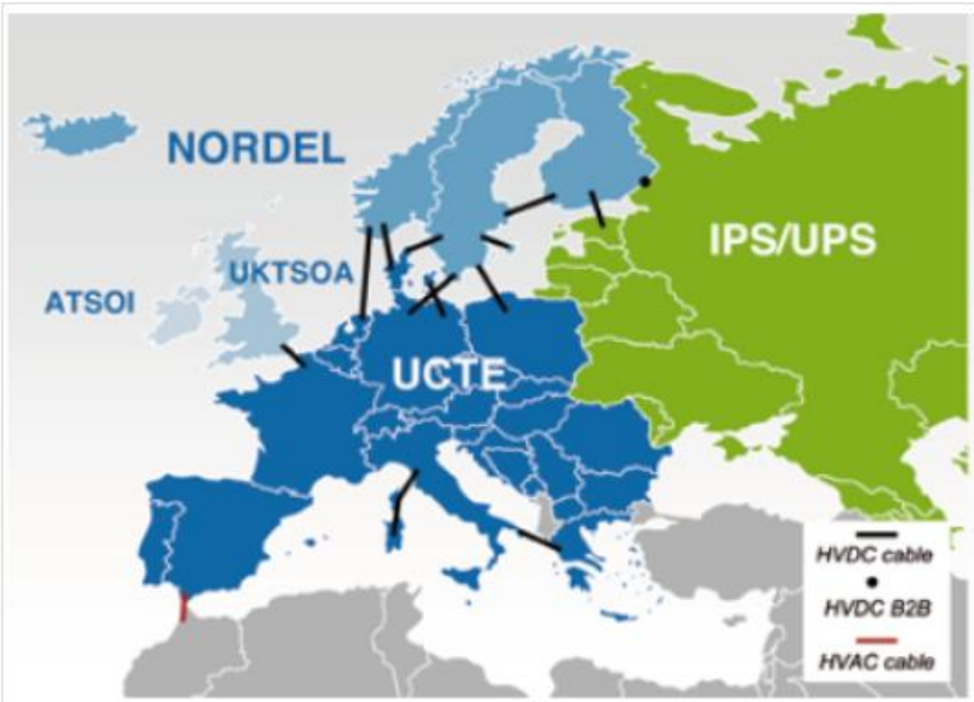


Figure 77: Overview of ENTSO-E RG CE (Former UCTE) and IPS/UPS synchronous zones

The principle of operation in the ENTSO-E RG CE is that each TSO is responsible for managing the security of operation of its own networks in a subsidiary way in compliance with the European Grid Connection Network Codes (the equivalent of the former UCTE Operational Handbook). Each TSO is responsible for instituting procedures to ensure reliability in its control area, from planning to real-time operation, including contingency and emergency conditions. Coordination between TSOs contributes to enhancing the shared solidarity to cope with the operational risks inherent to interconnected systems, to prevent disturbances, to provide assistance in the event of failures to mitigate their impact, and to provide restoration strategies and coordinated actions after a collapse.

The ***South East European countries*** Bulgaria, Greece, Hungary, Romania and Slovenia all operate synchronously within the ENTSO-E RG CE.
The non-EU countries in this area, Bosnia-Herzegovina, Croatia, Macedonia (FYROM), Montenegro and Serbia are part of this regional group as well and also operate synchronously within the ENTSO-E RG CE. The Albanian grid is not officialy part of the ENTSO-E group, but is operated synchronously as well.

There is also a working group working on inclusion of the Turkish grid into the ENTSO-E RG CE via existing power lines to Greece and Romania. Turkey would decouple itself from its other surrounding countries and join the ENTSO-E grid permanently. At present, this configuration is established on a trial basis that will lead to full implementation if this is successful.

The ***Mediterranean countries*** Italy and Spain are operating synchronously within the ENTSO-E RG CE. Special consideration has to be given to the interconnections between Mediterranean countries and the Maghreb countries (Morocco, Algeria and Tunisia). Presently, Maghreb countries operate synchronously with Spain through two 400 kV HVAC submarine cable connections between Spain and Morocco. The Spanish TSO REE is responsible for the operation of the Maghreb countries in parallel with ENTSO-E RG CE. Special protection schemes are in place to ensure that the Maghreb countries are disconnected from Spain in case of emergency, so as not to jeopardize the security of operation in ENTSO-E RG CE.

From the electrical system point of view, the ***North East European countries*** are in different synchronous operation zones. Estonia, Latvia and Lithuania are included in the BRELL synchronous operation zone (Belarus-Russia-Kaliningrad-Estonia-Latvia-Lithuania) which is a part of the IPS/UPS (see below) interconnected system. Estonia is asynchronously interconnected by an HVDC back-to-back link to Finland. Additionally, it is to be noted that the IPS of Russian Kaliningrad is tightly interconnected to the IPS of the Baltic States. The latter are now part of the European ENTSO-E but are synchronously interconnected with the IPS/UPS system.

Poland and the Slovak Republic are integrated into the Regional Group Continental Europe (RG CE) of the European Network of Transmission System Operators for Electricity (ENTSO-E). Finland is included in the Nordic Group of ENTSO-E. Finland is asynchronously interconnected via an HVDC back-to-back link to the IPS/UPS system (Russia) and via an HVDC cable connection to Estonia, the Estlink.

IPS/UPS
Apart from ENTSO-E, another major synchronously operating zone is the Interconnected Power System/Unified Power System (IPS/UPS) (see Figure 77). The IPS/UPS is a power union presently comprising the synchronously operated power systems of 13 countries: Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Mongolia, Russia, Ukraine and Uzbekistan (Figure 78). It is actually based on the

former USSR Unified Power System originally set up in the mid-50s of the last century and continuously extended up to now.

Synchronous operation of the power systems of Commonwealth of Independent States (CIS) countries is coordinated centrally by the Electric Power Council of the CIS (EPC CIS). Within the framework of the EPC CIS, the Commission on Operative-Technological Coordination of parallel operation of the power systems of the CIS and Baltic countries (COTC) establishes recommendatory principles of technological interaction and develops corresponding documents, the operation rules.

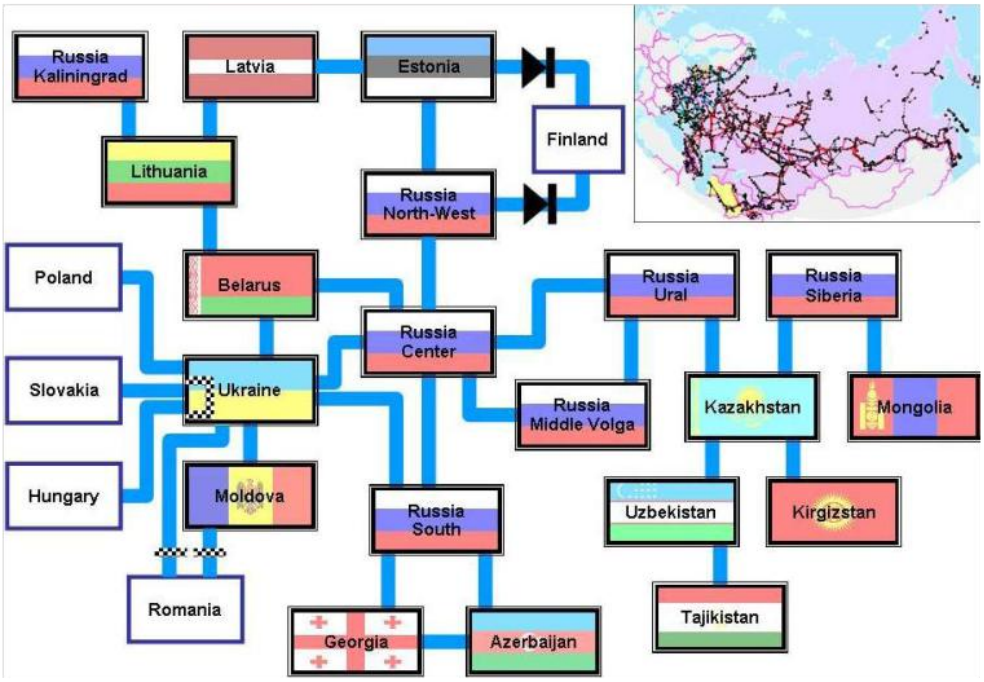


Figure 78: IPS/UPS system synchronous zone

Cooperation of the Baltic power systems with the power systems of CIS countries is performed within the framework of the BRELL Committee, which was established on the basis of multilateral international agreement between the TSOs of Belarus, Russia, Estonia, Latvia and Lithuania signed in 2002.

IPS/UPS is the world’s most geographically extended power system, spanning over eight time zones. Such vast territory implies certain specific features of the power system, such as:

- comprises internally almost balanced regional power systems connected mostly by congested links
- makes extensive use of long-distance EHV transmission lines up to 1150 kV
- uses automatic emergency control systems (in certain cases the N-1 criterion is only satisfied by the automatic emergency control system).

All power systems comprising the IPS/UPS are structurally allocated to 14 power regions:

- 6 IPSs in Russia: North West, Centre, Middle Volga, South, Ural, and Siberia
- Baltic States: Estonia, Latvia, and Lithuania
- Ukraine and Moldova
- Central Asia: Kazakhstan, Kirghiz Republic and Uzbekistan
- individual power systems of other countries: Azerbaijan, Belarus, Georgia and Mongolia.

Each power system regulates the active power balance with or without frequency deviation correction, with or without automatic systems. The UPS of Russia regulates frequency throughout synchronous zone.

Since 2003, the western part of the Ukrainian power system, the ‘Burshtyn TPP Island’, has been disconnected from the rest of the system and operates synchronously with ENTSO-E RG CE. There are connections to Bulgaria, Hungary, Poland and Slovakia. A passive island scheme is also in operation between Romania and Moldova.
The ENTSO-E RG CE has a system extension project group for system integration of Ukraine/Moldova on a long-term basis. So planned investments in HVDC connections risk becoming redundant after system integration.

Synchronous coupling to ENTSO-E
ENTSO-E and IPS/UPS have differing operating characteristics. Between 2005 and 2008, an extensive study on synchronous interconnection between IPS/UPS and ENTSO-E RG was undertaken. The results of the study showed that, although theoretically possible, synchronous coupling of the two systems may be considered only on a long-term perspective. A number of technical, operational and organisational measures have to be implemented, and the legal framework has to be established too. The implementation phase for carrying out the identified measures and creating the necessary conditions has been recognised as a long process. On a short time scale, the construction of asynchronous links (HVDC connections) may also be considered for system coupling. This certainly deserves further consideration and investigation by the stakeholders concerned.

The ENTSO-E RG CE has two system extension project groups for dealing with system integration and extension issues: Project Group Albania and Project Group Ukraine/Moldova. On a mid-term perspective (10 years), there are no other plans to extend the ENTSO-E RG CE synchronous operation zone by adding other power systems.

4.2.7 Regulatory environment in EU member states

The regulatory environment in the member states (MS) regarding energy and electricity markets is largely determined by the energy policy of the EU. Relevant directives on electricity generation are implemented in the legislation of each EU country. Climate and environmental policies provide a further legal framework that has to be considered before making investment decisions for power plants.

Generally, for the transition to liberalised electricity markets, it is likely that politics and markets have to be adjusted several times before a long-term stable situation is attained. Future energy policy development can hardly be predicted in detail but the general political vision for the EU is clearly stated in the green paper 'A European Strategy for Sustainable, Competitive and Secure Energy' [GreenPaper]. Sustainable energy development is the overarching goal. The Energy Roadmap 2050 adopted by the European Commission in 2011 [COM(2011) 885 final] sets the basis and strategy for developing the long-term European energy framework. The mission statement for the EU energy policy comprises the following four main goals as also anchored in the Treaty of Lisbon of 2007:

- integration of energy markets towards an efficient and competitive internal market
- security of energy supply
- enhancement of energy efficiency and energy savings
- development of new and renewable energy sources.

The enhancement and extension of the interconnection of European energy networks is stated as a further objective for achieving these goals. The main components of EU legislation that are relevant for power plant investment decisions concern environmental legislation and the Third Energy Package on the European internal energy market.

4.2.7.1 Environmental legislation

The most important environmental legislation that directly affects power plants comprises the following EU directives:

- The Large Combustion Plant (LCP) Directive [2001/80/EC]
- The Integrated Pollution Prevention and Control (IPPC) Directive [2008/1/EC]
- The Industrial Emission (IE) Directive [2010/75/EU]
- The Emissions Trading Scheme (ETS) Directive [2009/29/EC]

Large Combustion Plant Directive

The aim of the Large Combustion Plant Directive [2001/80/EC] is to cut gaseous pollutant emissions to the air, such as sulphur dioxide (SO_2), oxides of nitrogen (NO_x) and particulate matter. The LCP Directive applies to large combustion plants with a thermal input of at least 50 MW. It includes all large power plants running on solid, liquid or gaseous fuel. The LCP Directive stipulates that concentration-based Emission Limit Values (ELVs) have to be fulfilled for all new and existing plants. The ELVs to be applied depend on fuel, capacity and age of the combustion plant.

For new power plants authorised after 27 November 2002, compliance with a set of ELVs as laid down in Part B of the LCP Directive must be fulfilled (see Table 40). Concrete implementation of the LCP Directive by member states may even stipulate tighter ELVs. Of the EU countries concerned, for new plants tighter limits are only in place in Finland for NO_x emissions [ENTEC].

<table>
<tr><th colspan="2">All values are mg/m³</th><th colspan="3">Gaseous (3 Vol. % O2)</th><th colspan="3">Liquid (3 Vol. % O2)</th><th colspan="3">Solid (6 Vol. % O2)</th></tr>
<tr><th colspan="2">Load [MW]</th><th>≤ 100</th><th>≤ 300</th><th>> 300</th><th>≤ 100</th><th>≤ 300</th><th>> 300</th><th>≤ 100</th><th>≤ 300</th><th>> 300</th></tr>
<tr><td rowspan="5">SO2</td><td>General</td><td colspan="3">35</td><td>850</td><td>400-200*</td><td>200</td><td>850</td><td colspan="2">200</td></tr>
<tr><td>Biomass</td><td colspan="3"></td><td colspan="3" rowspan="4"></td><td colspan="3">200</td></tr>
<tr><td>Liquefied gas</td><td colspan="3">5</td><td colspan="3" rowspan="3"></td></tr>
<tr><td>Coke oven</td><td colspan="3">400</td></tr>
<tr><td>Blast furnace</td><td colspan="3">200</td></tr>
<tr><td rowspan="5">NOx</td><td>General</td><td colspan="3">200</td><td>400</td><td colspan="2">200</td><td>400</td><td colspan="2">200</td></tr>
<tr><td>Biomass</td><td colspan="3"></td><td colspan="3" rowspan="3"></td><td>400</td><td>300</td><td>200</td></tr>
<tr><td>Natural gas</td><td colspan="2">150</td><td>100</td><td colspan="3" rowspan="3"></td></tr>
<tr><td>GT natural gas</td><td colspan="3">50</td></tr>
<tr><td>Gas turbine</td><td colspan="3">120</td><td colspan="3">120</td></tr>
<tr><td rowspan="3">Dust</td><td>General</td><td colspan="3">5</td><td>50</td><td colspan="2">30</td><td>50</td><td colspan="2">30</td></tr>
<tr><td>Blast furnace</td><td colspan="3">10</td><td colspan="3" rowspan="2"></td><td colspan="3" rowspan="2"></td></tr>
<tr><td>Steel industry</td><td colspan="3">30</td></tr>
</table>

**linear descending*

Table 40: Emission limits for new power plants under the LCP Directive [RENA]

Integrated Pollution Prevention and Control Directive

The Integrated Pollution Prevention and Control Directive [2008/1/EC] was adopted in 2008 and repealed its predecessor version of 1996 [96/61/EC]. It requires that industrial activities with a high pollution potential must have a permit to ensure certain environmental conditions are met. The IPPC Directive applies to a variety of industrial activities, including the energy sector and combustion installations with a thermal input of at least 50 MW.

The IPPC Directive is a framework directive aiming at a high level of protection for the environment as a whole. As such, it covers all environmental media. The IPPC licensing system regulates effluent discharge, emissions to air, waste management, noise and other environmental impacts from specified activities by one integrated permit.

As a central principle of the IPPC Directive, installations to be operated under integrated permits must comply with environmental standards that are based on Best Available Technologies (BAT). Thus the IPPC Directive also provides for information exchange on BAT that results in the BAT Reference Documents (BREF) to be adopted by the European Commission. Permit stipulations must take into account the installation’s technical characteristics, its geographical location and local environmental conditions. To receive a permit, an industrial or agricultural installation must meet certain basic obligations [2008/1/EC]. In particular, it must:

- employ all appropriate pollution-prevention measures, namely the best available technologies that generate the least waste, use less hazardous substances, enable the substances generated to be recovered and recycled, etc.
- prevent all large-scale pollution
- prevent, recycle or dispose of waste in the least polluting way possible
- use energy efficiently
- ensure accident prevention and damage limitation
- return sites to their original state when the activity is over.

In addition, the decision to issue a permit must contain a number of specific requirements, including:

- emission limit values for polluting substances (except for greenhouse gases if the emission trading scheme applies - see below)
- any required soil, water and air protection measures
- waste management
- measures to be taken in exceptional circumstances, like leaks, malfunctions, temporary or permanent stoppages, etc.
- minimisation of long-distance or transboundary pollution
- monitoring of emission releases
- all other appropriate measures.

Industrial Emissions Directive
The Industrial Emissions (IE) Directive adopted in 2010 streamlines and enhances EU policy on industrial emissions. It came into force on 6 January 2011 and has to be implemented by national legislation by member states by 7 January 2013. The directive recasts seven other directives - among them the LCP Directive and IPPC Directive - and replaces them as of 7 January 2014. Only the LCP Directive will be repealed with effect from 1 January 2016.

The aim of the IE Directive is to reduce harmful industrial emissions across the EU, in particular through better application of Best Available Technologies. Like with the IPPC Directive, the IE Directive is permit based and aims at an integrated permit approach that takes into account the entire environmental performance of the plant covering, for example, emissions to air, water and land, generation of waste, use of raw materials, energy efficiency, noise, prevention of accidents, and restoration of the site upon closure. The permit conditions, including ELVs, must be based on BAT, as defined in the IPPC Directive.

The IE Directive will introduce stricter EU-wide ELVs for SO_2, NO_x and particulates in agreement with BAT levels from [LCP BREF 2006]. BAT reference documents have to be updated and adopted by the Commission within time periods of not more than eight years. For combustion plants in the energy sector, the IE Directive holds when the plant’s thermal input is at least 50 MW.

If, due to geographical location or local environmental conditions or the technical characteristics of the installation, the achievement of usual BAT-induced emission levels would lead to disproportionately higher costs compared to the environmental benefits, the licensing authorities are allowed to set less strict emission limit values in specific cases.

For new plants, the standards enter into force on 7 January 2013. The new ELVs for new large combustion plants are listed in Table 41.

Fuel & Technology	Input	NO_X	SO_2	CO	Dust
	MW(th)	mg/Nm³	mg/Nm³	mg/Nm³	mg/Nm³
Pulverised Lignite	50-100	400	400		20
Coal and Lignite and other Solid fuels	50-100	300	400		20
Coal and Lignite and other Solid fuels	100-300	200	200		20
Coal and Lignite and other Solid fuels	>300	150	150		10
Pulverised Lignite	>300	200	150		10
Coal and Lignite and other Solid fuels using fluidized bed combustion	>300		200		10
Biomass	50-100	250	200		20
Biomass	100-300	200	200		20
Biomass	>300	150	150		20
Peat	50-100	250	300		20
Peat	100-300	200	300		20
Peat using fluidized bed combustion	100-300	200	250		20
Peat	>300	150	150		20
Peat using fluidized bed combustion	>300	150	200		20
Liquid fuels (General)	50-100	300	350		20
Liquid fuels (General)	100-300	150	200		20
Liquid fuels (General)	>300	100	150		10
Liquid (Distillate) (Gas Turbine)	50-100	50	350	100	
Liquid (Distillate) (Gas Turbine)	100-300	50	200	100	
Liquid (Distillate) (Gas Turbine)	>300	50	150	100	
Nat. Gas (General)	50-100	100	35	100	5
Nat. Gas (General)	100-300	100	35	100	5
Nat. Gas (General)	>300	100	35	100	5
Nat. Gas (Gas Turbine)	N/A	50	N/A	100	
Nat. Gas (Gas Turbine & Eff. > 35%)	N/A		N/A	100	
Nat. Gas (Gas Engines)	N/A	75	N/A	100	

Table 41: ELVs for new power plants from 2013 on, as required by the IE Directive

The strict environmental standards usually favour gas-fired power plants. As a consequence of the IE Directive, all coal-fired units must have efficient electrostatic precipitation units or baghouse/fabric filters (cf. [IEA CCC]) plus flue gas desulphurisation units or equivalent technology to reduce SO_2 emissions down to 150-400 mg/m^3 (depending on plant size) or to achieve over 92% removal (depending on plant size and age). Furthermore, all coal-fired units must use low-NO_x burners and/or selective catalytic reduction/ selective non catalytic reduction to reduce NO_x emissions below 150-300 mg/m^3.

Emissions Trading Scheme Directive
Reduction of CO_2 emissions and other greenhouse gases (GHG) is not covered by the industrial emissions control regime described above, but is regulated separately. The ETS is the central instrument of the EU for controlling GHG emissions, particularly for those from power plants. The ETS covers inter alia all combustion installations with a rated maximum thermal input of at least 20 MW. The principle of the ETS is to cap the overall allowed GHG emissions and trade emission rights in order to economically optimise the EU-wide emission reduction efforts.

The ETS was launched with Directive [2003/87/EC] in 2005, and is organised into trading periods. With the ongoing second trading period from 2008 to 2012, the reduction commitment of 8% (compared to 1990 levels) of the Kyoto Protocol is pursued. Also burden-sharing among the EU MS is regulated. Each MS has its own emission cap. Most EU emission allowances (EUA) were allocated free of charge among the MSs according to national allocation plans (NAP). Only less than 4% of total EUA amounts were auctioned in phase 2. Since 2008, not only the 27 EU MSs but also Iceland, Liechtenstein and Norway take part in the ETS. Alongside emissions from the energy sector, emissions from some selected industries, too, fall under the ETS.

With Directive [2008/101/EC] aviation activities were included into the ETS. Directive [2009/29/EC] improved and extended the ETS for the third trading period, which is scheduled from 2013 to 2020. The scope was extended to include some further industries, to include further types of GHGs and to include rules for carbon capture and storage. About 43% of the EU’s total GHG emissions will be covered by the ETS by 2013. For power plant operators, the transition to the third operation period brings about some fundamental changes.

The European Council of March 2007 made a firm commitment to reduce the overall greenhouse gas emissions of the Community by at least 20 % below 1990 levels by 2020. With Directive [2009/29/EC], the EU provided for the contribution of the EU ETS to reach that target. The overall reduction target of the EU is subdivided by sectors depending on whether a sector falls under the ETS or not. For all ETS sectors, an overall emission reduction of in total 21% from 2005 to 2020 was defined. Accordingly, the EU-wide emission budget for all ETS sectors in total will be capped and gradually reduced. In case of an international agreement with the EU on stricter emission reduction targets of more than 20% by 2020, the ETS Directive provides for appropriate tightening of the ETS emission reduction targets.

Although free allocation of some EUAs is defined by EU-wide allocation rules, auctioning will become the basic principle for assigning EUAs. From 2013 on more than 50% of EUAs will be auctioned. This auctioned share will be steadily increased up to 100% in 2027.

The auctioning principle holds particularly for the energy sector. All power plants have to fully auction their emission rights. Only ten new MSs were given the option of exempting themselves until 2019 from the 'full auctioning' rule and continuing to allocate free of charge a limited number of emission allowances to existing power plants. These MSs are Bulgaria, Cyprus, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland and Romania. The revised ETS Directive stipulates that, even when this derogation is granted, the level of free allocation in 2013 may not exceed 70% of the allowances needed to cover emissions for the supply of electricity to domestic consumers. In each year following 2013, this%age has to decrease to zero in 2020. Most important: for new power plants no derogations at all are provided and full auctioning of EUAs is required from 2013 onwards.

Although the ETS cap is defined for the whole EU, each MS auctions its allocated share of emission rights. Determination of the volume of emission rights of each MS follows a certain procedure: Firstly, emission amounts dedicated for free allocation according to the EU-wide allocation rules are deducted from the total ETS cap. Secondly, a further 5% of emission rights is held back as a reserve for new market entrants. The remaining emission rights are dedicated for auctioning and allocated to the MSs. 88% of the auctioned emission rights is allocated to the MSs according to their shares in the EU emission inventory from 2005. A further 10% is allocated to specific MSs according to burden sharing rules for solidarity reasons. A further 2% is allocated to those MSs that had already attained in 2005 20% emission reductions compared to 1990.

The requirements under the ETS for new power plants in the EU are taken into account in the model by including the full costs from auctioning and acquisition of the EUAs. Accordant CO_2 price scenarios are taken from EC documents (see 5.1.1). For non-EU countries, no CO_2 emission costs are taken into account, which may lead to a specific competitive advantage, which is investigated in this study.

<u>Use of credits from the project based mechanisms CDM and JI</u>
Directive 2004/101/EC (the so-called ‘Linking Directive) allows participants in the EU ETS to use credits generated from the Kyoto Protocol’s project-based mechanisms CDM (Clean Development Mechanism) and JI (Joint Implementation) for fulfilling their obligations under the trading scheme.

CDM and JI have in common that they enable investments in emission reduction projects, like renewable energy and energy efficiency measures, abroad in countries that are also party to the Kyoto Protocol. In the case of JI, these investments are undertaken in countries which in turn have an emission reduction obligation. In the case of CDM, these projects are implemented in countries with no obligation (developing countries).

For every ton of CO_2 that is reduced by a CDM or JI project, a carbon certificate is issued that can be used in the EU ETS. In the case of CDM these credits are called Certified Emission Reductions (CERs). In JI projects Emission Reduction Units (ERUs) are generated. The idea is that emission reductions achieved with CDM or JI projects can be more cost-efficient for EU ETS participants in comparison to implementing more expensive emission reductions within the EU.

The use of CERs and ERUs in the second trading period is allowed and remaining unused credits from this period can be transferred for use in the third trading period. Also credits from pre-2012 registered CDM projects that will be generated after 2012 can be used. In any case, the use of CERs is restricted to 50% of the reduction effort. However for the third trading period, the ETS Directive restricts the use of CERS and ERUs from <u>new</u> CDM and JI projects that have been registered post-2012 unless:

- a satisfactory international agreement on climate change is approved by the Community
  or, in the absence of such an agreement
- the EU enters into a bilateral agreement with a country.

An exemption is the acceptance of credits from new projects implemented in Least Developed Countries (LDCs) after 2012. These can be used in the third trading period even in the absence of such agreements as listed above. However, among the non-EU countries contiguous with the EU there are no LDCs.

As there has been neither an international agreement up to now nor have there been any EU agreements with third countries, the use of CERs and ERUs from new projects registered beyond 2013 is currently prohibited for the third trading period.

4.2.7.2 Third Energy Package

The liberalisation of the European energy markets was triggered already in 1996 with a first energy package. It mandated all MSs to provide for a competitive electricity market. The main contents of the second energy package brought the obligation for vertically integrated power utilities to unbundle under company law and organisationally. It would see electricity generating companies separated from their transmission networks. Furthermore, MSs were mandated to establish a regulation authority and implement a system for regulated grid access.

The third legislative package for an internal EU gas and electricity market was adopted in July 2009 and came into force in March 2011. The third energy package comprises:

- Directive [2009/72/EC] concerning common rules for the internal market in electricity
- Directive [2009/73/EC] concerning common rules for the internal market in natural gas

- Regulation [2009/713/EC] establishing an Agency for the Cooperation of Energy Regulators (ACER)
- Regulation [2009/714/EC] on conditions for access to the network for cross-border exchanges in electricity
- Regulation [2009/715/EC] on conditions for access to the natural gas transmission networks.

The energy package aims at bringing energy markets closer to the ideal of one competitive and fully integrated market. Basic elements are:

- public service obligations and customer protection
- structural separation between transmission activities and production/supply activities of vertically integrated companies (further unbundling regulation)
- empowering and independence of national, sector-specific regulators
- new tools to harmonise market and network operation rules at pan-European level
- establishment of the institutional framework for ACER and ENTSOs.

With regard to natural gas markets, Directive [2009/73/EC] redefines rules and measures applying to natural gas markets to increase market transparency and guarantee fair competition and appropriate consumer protection.

With regard to electricity markets the Directive [2009/72/EC] introduces common rules for the generation, transmission, distribution and supply of electricity. Persons from third countries are allowed to control or operate a transmission system only if they comply with the requirements of effective separation that apply inside the Community. For unbundling, the Directive grants MSs a choice between three possible models:

- Ownership Unbundling (OU)
- Independent System Operator (ISO)
- Independent Transmission System Operator (ITO)

The unbundling initiative shall facilitate non-discriminatory access to transmission networks and fair competition between suppliers. It shall furthermore stimulate investment in interconnectors which may negatively impact the market share of the vertically related supplier.

With OU, the TSO owns and manages the transmission network. The supplier shall have no control on the TSO and shall only be allowed to hold minority shares but with no voting rights and no rights in appointment of TSO administrators. A Member State has the right to opt for full OU in its territory. Where a Member State has exercised that right, an undertaking does not have the right to set up an ISO or an ITO. Furthermore, an undertaking performing any of the functions of generation or supply cannot directly or indirectly exercise control or any right over a transmission system operator from a Member State that has opted for full ownership unbundling [Säcker].

According to the ISO model, the vertically integrated company still owns the transmission network. Effective unbundling is based on a pillar of organisational measures and measures relating to the governance of transmission system operators and on a pillar of measures relating to investment, connecting new production capacities to the network and market integration through regional cooperation [Säcker].

The independence of the transmission operator should also, inter alia, be ensured through certain 'cooling-off' periods during which no management or other relevant activity giving access to the same information as could have been obtained in a managerial position is exercised in the vertically integrated undertaking.

The establishment of an ITO is a third alternative for the unbundling mechanisms. Unlike an ISO, an ITO must not be broken off from the vertically integrated company. Instead strict rules shall guarantee the independence of the ITO from the remaining part of the company. Independence implies separation of assets, installations and staff, and must be implemented by company law. Commercial and financial business transactions between the two parties must be in accordance with usual market conditions and must be made fully transparent to the regulatory authority. Additionally, an ITO is required to establish a non-discrimination programme to guarantee non-discriminatory grid access rules and processes.

Apart from unbundling requirements, all European TSOs organised under ENTSO are mandated to undertake trans-European cooperation and common planning to establish a European supergrid. Furthermore, TSOs should facilitate the participation of final customers and final customers' aggregators in reserve and balancing markets [Säcker].

Cross-border trade

The EU regulation for cross-border electricity trade provides access to the network for cross-border exchanges to create an internal market for electricity and an increase of cross-border electricity flows. Because the demand for cross-border power transfer can exceed transmission capacities, the regulation sets an auction system for non-discriminatory access to transmission capacities. According to [2009/714/EC], the conditions of the auction process are formulated for management of congestion problems and should provide correct economic signals to transmission system operators and market participants in a market-based mechanism.

The cross-border capacity trade for electricity transmission in the ENTSO-E area is transacted directly between the TSOs concerned, who have to coordinate their congestion management in regional clusters. Some TSOs, though, have established common platforms to simplify and centralize the allocation procedure, e.g. the CASC.EU. This auction office trades the cross-border transmission capacity for Central Western Europe, the borders of Italy, Northern Switzerland and parts of Scandinavia [CASC]. Transmission system operators that are not allied in overarching trade platforms organize their allocations together with the appropriate TSO of the bordering country. In this case, they set up joint ventures to transact the capacity allocation business or come to an agreement that one of the operators organizes the allocation system.

The TSOs have to undertake temporal segmentation of the ATCs they provide. The allocated capacities are set in yearly, monthly, daily and intraday periods, although there are variants. Some TSOs also have quarterly and weekly periods for their auctions. The structure of the quantity of the allocation per time unit is determined by the TSO. Every relevant item of information on tendered values, registration for the bidding process, net availability as well as conditions and allocation principles have to be published by the TSOs, and these are mostly available on their websites.

The volume of the overall available capacity can be assigned in two ways. Long-term rights are often allocated in the explicit market where only the transmission right can be acquired whereas short-term rights (day ahead and intraday) are mostly auctioned in the implicit market, also known as market coupling or market splitting. In this case, the transmission right is brought together with the electricity. The implicit market was established to maximize the benefit of the capacity and the generation market, and to make use of price signals that result in an easier power flow from low-price areas to high-price areas [MAR].

In the allocation procedure, the tendered capacity is awarded to the highest bid. Just before the allocated timeframe for the use of the transmission capacity, the owner has to inform the TSO of the extent to which he will use his option. Potential vacancies of the net capacity will be offered again in the next window of opportunity. It is also possible to trade transfer rights in the secondary market, although the TSOs can prohibit this procedure.

Revenues from capacity auctions are shared by the TSOs concerned and have to be reinvested in new cross-border transmission lines, maintenance and operation of existing capacities or implementing net cost reductions, although there are exceptions that apply under specific conditions.

With its Third Energy Package and subsequent legislation, the EU has established an obligatory inter-TSO compensation mechanism (ITC) [THINK]. Under the ITC, TSOs are compensated for all costs incurred as a result of hosting cross-border flows of electricity on their networks by those TSOs from whose systems cross-border flows originate or where they end. The costs shall be established on the basis of the forward-looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate share of the cost of existing infrastructure.

The concrete ITC methodology currently applied is laid down in Regulation 838/2010. Its central element is an ITC fund which shall provide (separately calculated) compensation payments. The fund is calculated and distributed annually based on an ex-post analysis. Contributions to the fund are determined based on TSOs' "proportion to the absolute value of net flows onto and from their national transmission system as a share of the sum of the absolute value of net flows onto and from all national transmission systems". Thus the larger the imbalance between import and export flows of a country, the larger will be its payment into the fund.

Third country import and export flows, termed perimeter flows, shall contribute to the fund. The "perimeter fee" is fixed annually per MWh transit. The unit price perimeter fee for 2012 is 0.80 €/MWh.

4.2.8 Regulatory environment in non-EU countries

Among the analysed non-EU countries, the regulatory environments for investments in new power plants are generally specific for each country. However, for the members of the European Energy Community (EEC), the EEC treaty provides a common regulatory basis for PP investment conditions and for electricity transmission. Thus the EEC and its relevance for the analysed PP investment situations are introduced in 4.2.8.1.

The EEC is particularly relevant for regulating the market for (international) electricity transmission. Whether access to the grid and to transmission capacities for electricity transfer into the EU is possible without discrimination and at reasonable conditions is of vital interest for a potential PP investor (cf. section 4.2.8.2).

For non-EU countries, less strict environmental regulation for power plants may be in force compared to EU power plants. This may allow power plants to be installed without some of the environmental protection features required by EU legislation or without paying attention to carbon costs. This issue is discussed in 4.2.8.3. Also the impact of policies on the supply of renewable energy in the targeted market in the EU is analysed in this section.

4.2.8.1 Energy Community

The Energy Community (EEC) lays down a legal framework between the European Union and South East European as well as other countries contiguous to the EU. Its purpose is to extend the European internal energy market to other countries.

The EEC Treaty was signed in 2005 by the European Community and then nine Contractual Parties from South East Europe (cf. Figure 79). Following ratification, the Treaty came into force on 1 July 2006. In Dec 2009 the Energy Community Ministerial Council decided on the accession of Moldova and Ukraine. With this decision, the geographical concept of the Western Balkans, with which the process was initially linked, lost its validity. Today, the motive behind the Energy Community Treaty is rather the import of EU energy policy into non-EU countries. [EEC]

Figure 79: Map of the Contractual Parties of the EEC

Among the non-EU countries analysed in this study, the European Energy Community provides a common regulatory basis for:

- Albania
- Bosnia and Herzegovina
- Croatia
- FYROM (Former Yugoslav Republic of Macedonia)
- Moldova
- Montenegro
- Serbia
- Ukraine

Turkey is among the countries with an observer status but its membership is desired on the part of Turkey as well as on the part of the EU. Thus it can be assumed that potential power plant investments in Turkey even now and certainly in the foreseeable future will have to comply with EEC rules so as not to run the risk of turning into stranded investments after Turkey's accession to the Energy Community. For this reason, our analysis of the investment conditions in Turkey considers the situation of Turkey as already being a member of the Energy Community.

Aims of the Treaty establishing the Energy Community

According to Article 2, the task of the Energy Community is to structure the relationships between the parties and create a legal and economic framework in relation to Network Energy in order to [EEC-LF_2010]:

- create a stable regulatory and market framework capable of **attracting investment** in gas networks, power generation, and transmission and distribution networks

- create a **single regulatory space** for trade in Network Energy as needed to match the geographic extent of the product markets concerned

- enhance the **security of supply** of the single regulatory space

- improve the **environmental situation** in relation to Network Energy and related energy efficiency, foster the use of renewable energy, and set out the conditions for energy trading in the single regulatory space

- develop Network Energy market **competition** over a broader geographic spread and exploit economies of scale.

To facilitate this process, the Treaty establishing the Energy Community defines the institutional setting and equips its stakeholders with specific rights and duties.

Commitments by the Parties under the Treaty

As regards the commitments undertaken by the Parties to the Energy Community, Article 3 of the Treaty establishes a three-tier structure which may be described as the Treaty's concentric circles:

The first, innermost circle in Title II of the Treaty "**The Extension of the Acquis Communautaire**" addresses the Contractual Parties alone. Under the Treaty, they have agreed to implement core parts of the EC acquis communautaire, both sector-specific and in general. The Energy Community acquis comprises the core EU energy legislation in the areas of electricity, gas, environment, competition, renewables and energy efficiency. Furthermore, Articles 24 and 25 of the Treaty allow for adaptation of the acquis and implementing amendments made to it in the course of evolution of EC law. After its coming into force, the Energy Community acquis has been extended to include new energy policy areas as well as to replace older acts by newer, revised ones. Separate acquis outline the several energy fields [EEC].

Title II also requires the Contractual Parties to adopt development plans with a view to bringing their energy sectors in line with generally applicable standards of the EC.

The second circle in Title III of the Treaty “**Mechanism for operation of Network Energy Markets**” addresses the Contractual Parties as well as seven EU member states connected to the region, namely Austria, Bulgaria, Greece, Hungary, Italy, Romania and Slovenia. Title III contains provisions for creating mechanisms for long-distance transportation of Network Energy, adopting security of supply statements and promoting high levels of energy provisions to citizens. It also urges harmonization of market designs, mutual recognition of licenses and fostering free establishment of companies, fostering development in the areas of renewable energy sources and energy efficiency, as well as providing a framework for safeguarding measures in the event of a sudden crisis. For the greater part, the provisions in Title III require implementation through measures taken or to be taken by the competent Energy Community institutions.

Finally, the third circle in Title IV of the Treaty “**The Creation of a Single Energy Market**” addresses the Contractual Parties as well as the entire European Community, i.e. all Parties. Basically, it provides for the free movement of network energy and allows for further measures to be taken with a view to creating a single energy market. Furthermore, Title IV establishes an external energy trade policy and provides for a mechanism of mutual assistance between the Parties in the event of energy disruption. Further Titles (V-XII) refer to the organizational structures, such as the institutions of the community, the decision making process, implementation, regulatory aspects and dispute settlement [EEC].

The Acquis Communautaire of the EEC

The Acquis Communautaire of the EEC includes (among others) the following EU Directives and Regulation:

ACQUIS COMMUNAUTAIRE ELECTRICITY

- **Directive 2003/54/EC** concerning common rules for the internal market in electricity
- **Regulation (EC) No 1228/2003** on conditions for access to the network for cross-border exchanges in electricity, incl. amending **Decision 2006/770/EC**.
- **Directive 2005/89/EC** concerning measures to safeguard security of electricity supply and infrastructure investment
- **Directive 2001/77/EC** on the promotion of electricity produced from renewable energy sources in the internal electricity market

The Ministerial Council, furthermore, adopted the **third legislative package for an internal EU gas and electricity market** (cf. section 4.2.7.2) in October 2011. The general implementation deadline is set for 1 January 2015, only **Article 11 of Directive 2009/72/EC** (regarding ‘certification in relation to third countries’) shall apply from 1 January 2017. With regard to the EU regulation regarding cross-border electricity trading and congestion management, the Permanent High Level Group of the Energy Community drafted recently a decision to implement EU Regulation 838/2010 (cf. section 4.2.7.2 above) by 1 January 2013 for all Energy Community Members.

ACQUIS COMMUNAUTAIRE ENVIRONMENT

The acquis on environment shall be implemented insofar as it affects network energy. It includes inter alia:

- **Directive 85/337/EEC** on the assessment of the effects of certain public and private projects on the environment, as well as **Directive 97/11/EC** amending Directive 85/337/EEC
- Directive **2003/35/EC** providing for public participation in respect of the drawing up of certain plans and programs relating to the environment and amending with regard to public participation and access to justice Directives 85/337/EEC and 96/61/EC.
- **Directive 2001/80/EC** on the limitation of emissions of certain pollutants into the air from large combustion plants (LCP Directive)
- Each Contracting Party shall endeavour to implement **Directive 96/61/EC** concerning integrated pollution prevention and control (IPPC Directive), codified by **Directive 2008/1/EC** (cf. section 4.2.7.1).

In May 2012, all Contractual Parties noted the major challenges entailed in implementation of the LCP Directive [EEC_taskforce], which must be implemented after a transitional period by the end of 2017. Problems of implementation concern, though, particularly retrofits and environmental adjustments of existing plants, which is hampered mainly by lack of finance. Most important: According to Article 15 of the treaty, construction and operation of new power plants shall comply with the acquis communautaire on the environment by when this treaty comes into force, i.e. since 2006.

According to Article 13 of the Treaty, the Contractual Parties recognise the importance of the Kyoto Protocol and shall endeavour to accede it. Although no explicit access to the EU ETS is mentioned in the Treaty, Article 13 represents the political commitment of the Contractual Parties to enhance climate protection standards. This may send a signal to potential power plant investors that further limitations to CO_2 emissions are planned for the EEC countries.

ACQUIS COMMUNAUTAIRE COMPETITION

The competition acquis shall be implemented insofar as trading of network energy between the Contractual Parties may be affected. It rests on three pillars:

1. A prohibition on cartels corresponding to **Article 81** of the EC Treaty.
2. A prohibition on abuses of dominant positions corresponding to **Article 82** of the EC Treaty.
3. A prohibition on state aid corresponding to **Article 87** of the EC Treaty.

Moreover, the principles of the EC Treaty regarding public undertakings and undertakings to which special or exclusive rights have been granted, in particular **Article 86(1) and (2) EC**, apply to the Contractual Parties. These articles prohibit state-organised restrictions of competition and defend undertakings with special missions that provide services of general economic interest (SGEI). Generally, the entire liberalisation of the electricity market is to be concluded by January 2015.

The regulations and structures for cross-border capacity trade within the ENTSO-E union have also been adopted by the Energy Community in its decision No. 2008/02/MC-EnC and therefore apply for the member states [EEC-LF_2008]. As a consequence for power plant investments in these countries, a transparent and non-discriminatory grid access as practised within the EU and described above can be assumed.

However, there are some pending dispute cases that concern the lack of or incorrect implementation or application of the EEC rules in some EEC members. Disputes are managed within a so-called dispute settlement mechanism to enforce the obligations assumed by the Parties that signed the Treaty. The most prominent example with regard to the focus of this study is the dispute settlement formulated by the Energy Community Secretariat in January 2011 (CASES NO. 01-06/11). Albania, Bosnia and Herzegovina, Croatia, the former Yugoslav Republic of Macedonia, Montenegro and Serbia are requested to adopt a common coordinated congestion management method and procedure for the allocation of transmission capacity to the market. This obligation was due as from 31 December 2009.

COMPLIANCE WITH GENERALLY APPLICABLE STANDARDS OF THE EUROPEAN COMMUNITY

Within one year of the date of entry into force of this Treaty, the Secretariat shall draw up a list of the Generally Applicable Standards of the European Community, to be submitted to the Ministerial Council for adoption. The Contractual Parties shall, within one year of the adoption of the list, set up development plans to bring their Network Energy sectors into line with these Generally Applicable Standards of the European Community. "Generally Applicable Standards of the European Community" shall refer to any technical system standard that is applied within the European Community and is necessary for operating network systems safely and efficiently, including aspects of transmission, cross-border connections, modulation and general technical system security standards [EEC].

Meaning of the EEC for PP investments and electricity import to EU.
The countries of the Energy Community regulate their grid access for new power plants on the basis of relevant EU regulations. The respective directive 2009/72/EC concerning the common rules for the internal market in electricity describes non-discriminatory grid access for new power plants and was adopted by the EEC.

The TSOs have to organise a transparent procedure to check if the grid capacity is sufficient for a requested power plant capacity and justify their result by submitting calculations, pertinent data and evaluation criteria. Furthermore, in case of a refusal, the TSO has to provide relevant information on the measures that would have to be taken to extend the grid system to gain grid access. In general, only insufficient grid capacity can lead to a negative response.

Originating from this regulation, a non-discriminatory access for IPPs in the member states of the Energy Community can be regarded as assured. Furthermore, the EEC implies non-discrimination rules for transmission capacity booking and for transmission pricing. It is assumed that deficiencies and disputes on implementation of the common EEC rules will have been resolved within the period under investigation, i.e. by 2020, and are thus not considered further in this study.

For electricity export from EEC countries into EU countries, the EEC treaty is of supreme importance, because this provides for an intergovernmental connection agreement that generally allows transmission links between the countries concerned with the EU.

4.2.8.2 Electricity market regulations in non-EU countries

Electricity markets in the member states of the Energy Community are on their way to implementation of European Standards (cf. 4.2.8.1 above). For non-EU countries not being a member of the Energy Community, the following regulations concerning cross-border electricity flows and capacity allocation exist:

Considering **Turkey** it can be said that the country is an observer of the EEC and expressed its interest in a full membership of the Energy Community [EEC-OBS]. Additionally, Turkey is in the linking process to the ENTSO-E grid and establishes an capacity auction system following the European idea of liberalisation [TTOEU][TCBETL][TEIAS-ENTSOE]. The new Electricity Market Import and Export Regulation provides that wholesale companies are eligible for import/export of electricity and capacity allocation procedures are managed by the TSO TEİAŞ. Furthermore, synchronous connections capacity to the ENTSO-E region is allocated by explicit auctions and over-the-counter trade of the capacities is permitted. The period of allocation of whole or some portion of capacity an interconnection line to a single user shall not be more than one year. The allocation method generally underlies the principle of non-discriminatory conducts, the development of competition and appropriateness of method with liberal market aspects [TEIAS][NARUC].

The Baltic electricity network is highly integrated into the power system of **Russia**, which currently helps the Baltic countries to maintain supply adequacy. However, a long term political goal is for the Baltic countries to desynchronise from the Russian network and synchronise to the EU network. The timing of desynchronisation from the Russian network is unlikely to take place before 2020 [ELFORSK].

The EU set up a Baltic Energy Market Interconnection Plan (BEMIP) for integration of the Baltic States into the EU energy networks. The target year for the full implementation of a common Baltic electricity market integrated with Nord Pool has been fixed at the year 2015 [CESI]. It shall be consistent then with the key elements of the Nordic market design, which inter alia include:

- implicit auction between Baltic countries and towards Nordic countries on a single trading platform
- market transparency according to EU standards
- harmonized network tariffs for generators
- a common position and trading principles towards third countries.

In the long term, physical transactions from suppliers of non-EU countries like Russia and Belarus might be envisaged through participation to the power exchange or by means of bilateral contracts, provided that ‘reciprocity’ in the market rules as well as in the environmental and safety standards is ensured [CESI].

Electricity markets in Russia are completely different designed than those in EU countries. This complicates electricity exports from Russia. Russia applies the nodal pricing model (ca. 8000 nodes in Russia), where each node is assigned to an own price. This limits hedging possibilities via financial contracts. Furthermore, the Russian electricity market is an ‘energy and capacity’ market. As a result, the exporter’s capacity payment depends on the forecast exports during peak hours. Capacity has to be reserved in advance on a monthly basis and has to be paid regardless of whether the capacity is used. Additionally, trading is complicated by different market designs and trading cycles in the Russian day-ahead markets compared to the Nordic market design [LUT].

There is no general framework on conditions for cross-border power trade that count for all bordering countries of Russia. A free access to cross-border capacities is not given and there is no explicit or implicit auction mechanism of transmission capacity [Fortum][EURELEC][DMOERF]. Eurelectric and the CIS Electric Power Council are in a dialogue for establishing compatible market rules. However a commitment from the EU and **CIS** to prioritise the development of the functionality of the cross-border trade is lacking [Fortum].

The bilateral trade between Finland and Russia is arranged with one Russian exporter (Inter Rao, 1300 MW) and two Finish importers (RAO Nordic Oy, 980 MW and Inter Green Renewables and Trading AB, 320 MW). In addition, 100 MW is available for direct trade at Nord Pool Spot [LUT] and about +/- 100 MW for automatic frequency regulation in the Finish system [Inter Rao]. Power transmissions are only feasible from Russia to the Finish market [19] [20]. Free access to cross-border capacities is in practice not available due to the balancing responsibility on the borders assigned to Inter Rao. A market based allocation of cross-border capacity is missing [Fortum].

Electricity markets in the **Maghreb** countries are characterised by the so-called ‘single buyer’ model. In the single buyer system, the producer and the eligible customer contract on a certain volume [EUI]. Then the single buyer, which is usually the TSO, buys the electricity from the producer at the price agreed between them minus the cost of transport and distribution. The electricity is then resold to the buyer at the price primarily agreed with the producer. In the case where the single buyer does not have a duty to buy, negotiated or regulated Third Party Access (TPA) applies. The single buyer model raises important problems of transparency and accounting unbundling [EUI].

However during recent years Maghreb countries modernised their electricity market regulations in the course of the envisaged overall strategy of Mediterranean countries to close the Mediterranean Energy Ring (MEDRING).

In **Algeria** the electricity law (n°02-01 for electricity and gas distribution) for the liberalisation of the Algerian electricity market was approved in 2002 [CREG]. The Law lays down all the provisions for the unbundling of the former vertically integrated utility, SONELGAZ, as well as the role of each market actor and the market model. The transmission system is operated by one single grid operator (article 29). The system operator shall work in a transparent and not discriminatory way. The law does however not clearly state how the electricity trading and the allocation of transmission capacity are to be organised [CREAD]. An auction mechanism does not exist [MEDREG 2011].

An independent Regulatory Commission for Electricity and Gas (Commission de régulation de l’électricité et du gaz, CREG) was established. CREG shall (art. 113) oversee the competitive and transparent functioning of the electricity market. The regulator has the power to approve the system operator rules. In addition he also has the power to ask for modifications before approval. Article 128 of the law on electricity states that operators have to agree with the CREG sale and purchase contracts of electricity. This provision permits CREG to know the exact quantity and nature of the electricity sold in the market [CREAD].

The power generation sector was opened to private and public operators (articles 6 and 7 of the electricity law) [CREG]. The law introduces competition in the electricity generation segment, by principally permitting any natural or legal person to install electricity generation capacities. A formal permission by the regulatory commission for each new power plant over 25 MW is required [CREAD].

Article 85 of the electricity law explicitly allows the export and import of electricity, which can be performed by any legal or natural person [CREG]. The transit tariff is set by bilateral negotiations [MEDREG 2011]. International electricity transactions have to be confirmed by the regulatory commission (CREG), which can refuse export activities if they have strong negative impacts on the national Algerian electricity supply (i.e. if demand cannot be satisfied). Power plants that have been constructed exclusively for the export of electricity are exempted from this reservation (article 86) [CREG] – a clause that opens a legal door for pure export projects, such as Desertec. However, transmission lines for export purposes only must not be owned by private entities [CREAD].

According to the law, the state electricity and gas monopoly SONELGAZ, which is also responsible for operation, management and development of the grid, shall unbundle its activities [CREG]. As a consequence, the company SONELGAZ has been restructured in the form of a holding company. SONELGAZ/O.S. (Operateur Système) is responsible for the operation and planning of the grid, but is not the owner. The network assets are owned and utilised by SONELGAZ/GRTE, Gestionnaire réseau de transport électricité [MEDRING_UP1]. SONELGAZ/O.S. as well as SONELGAZ/GRTE are 100% subsidiaries of the SONELGAZ holding [UIR].

The Algerian law of finance from 2009 constitutes a regulatory barrier for international investors. Its article 58 stipulates that all the economic activities in Algeria have to be done in partnership with Algerian shareholders. Foreign trade companies can only hold up to 70% of the capital of a company in Algeria. For all other economic activities, foreign companies are allowed to have a domestic maximum share of 49% of the capital [LDF_2009] [GTAI].

In **Tunisia**, private power generation projects are allowed since 1996. The Tunisian state-owned electricity company (STEG) declared its intention to create a North African electricity market, and to integrate it into the European. The progressive integration of the Algerian, Morocco and Tunisian electricity markets in the internal EU electricity market project is a follow-up to the Protocol Agreement signed in Rome by the three Maghreb countries and the EC in 2003. The objectives are:

- Harmonizing the legislative and regulatory framework as well as the industrial structure of the beneficiary countries to create a market of electricity.
- Make them compatible, for a second time, with European standards in order to integrate this market with the EU one.

The National Agency for Energy Management (ANME) established by the Law No. 2004-72 of 2 August 2004, has, as part of its mandate, responsibility for regulating the energy sector in the country. [REEEP] In February 2009 a new law was passed committing STEG to buy electrical surplus generated by self-producers from renewable energy and to lease them its transmission system to transport the surplus from an establishment to another within the same group.

The Tunisian electricity sector is managed by vertically integrated utilities. Currently, the main actor is STEG, being the exclusive electricity distributor and TSO. STEG also owns a large part of the existing power generation facilities [MEDRING_UP1]. STEG has exclusive rights to import and export electricity [GENI]. The current Tunisian legal framework provides only for the production of electricity for own needs or intended for sale to STEG. It does not provide for private production of electricity to be sold directly on the market or exported [CONS].

Law No. 2009-7 allows power auto-production from renewable energy with a right to sell to STEG up to 30% of power generated at a price equivalent to high tariff prices [ANME]. Auto-producers are allowed to use the national grid to transport power to point of consumption, on payment of a transport fee, currently set at 0.005 DT / kWh [ANME]. The new electricity transport contract allows self-producers to use sub-contracting in order to ensure electricity production [ANME]. Decree No. 2009-2773 is fixing the conditions for power transport, the surplus sale to STEG and upper limits of these surpluses. The prices are set by order of the Minister of Energy [ANME].

A major obstacle for the creation and development of regional electricity trading in the Mediterranean area is the lack of shared rules on capacity allocation, congestion management and inter-TSO compensation mechanisms. The setting up of shared rules on the above issues is a mandatory prerequisite for the free trading both between SEMC (Southern and Eastern Mediterranean Countries) and with the NMC (Northern Mediterranean Countries) [MEDRING_UP1].

In order to develop interconnection capacities, the **IMME Project** (Intégration des Marchés Maghrébins de l'Electricité) has been launched. IMME supports the development of an integrated electricity market between Algeria, Morocco and Tunisia and between these three Maghreb countries and the EU, through the harmonization of their legislative and regulatory framework. The project focuses on the development of an integrated electricity market among these three Maghreb countries, through the adoption of a strategy, together with a plan of action, that will help them adapt their legislative and regulatory framework. It also enhances the technical knowledge of the different actors, including regulators and ministries, with a view to creating a market that is compatible with the legislative framework of the EU electricity market. These objectives motivated the signature of the "Algiers Declaration" on 20 June 2010 by the three Energy Ministers of Morocco, Algeria and Tunisia, in the presence of the Energy Commissioner of the EU. According to the Algiers Declaration the signing countries inter alia

- reaffirm their desire to pursue the reforms of the national energy sectors,
- pursue actions designed to harmonise the legislative and regulatory frameworks and the technical and economic conditions required to create a viable electricity market in and between the three Maghreb countries and their integration into the European Union market,
- agree that access to the networks must be non-discriminatory and transparent, and subject to appropriate pricing,

- invite the network managers to draft a set of common rules to facilitate cross-border trade in electricity,
- emphasize the importance of developing new and renewable energies, of promoting energy efficiency and of safeguarding the environment within the framework of electricity market integration, pursuing a sustainable development approach,
- approve the Action Plan appended to the declaration,
- mandate the permanent High Level Group to set up a monitoring committee responsible for its implementation.

The second action of the IMME action plan is set out as follows: "To set up in each country appropriate regulation authorities" [EEAS].

4.2.8.3 Environmental policies

Environmental regulation in non-EU countries may stipulate considerably different emission limit standards for power plants compared to the respective EU standards. Particularly if the non-EU ELVs are low, one may suppose a competitive advantage to install a low technology power plant in the non-EU country instead of a high tech power plant within the EU. Installation of the power plant outside the EU would save investment costs for installation of excess air cleaning devices or other environmental protection installations.

However, in fact for investments into new power plants, there exist environmental standards defined by World Bank that are implicitly effective if national standards within a country are low. The reason is that for a power plant investment it is common and essential to be financed by an international bank consortium. These credit consortiums are mainly established for large exposures, to minimize and share the risks that come along with such a large investment. Otherwise, risks would be too high for a single lender in the case of a power plant investment. The World Bank standards are the internationally accepted standards that each power plant investment usually has to fulfil in order to become bankable.

From a comparison of the World Bank ELV standards (see Table 42) with the ELV standards for new EU power plants as set by the EU IE Directive (cf. Table 41) it becomes evident, that EU standards fulfil the World Bank standards. But on the other hand, World Bank standards are high enough to urge for ambitious technologies. Fulfilling the only little more stringent EU standards means only marginal additional investment costs for the EU power plant compared to the non-EU power plant, if any additional costs at all. Therefore equal investment costs for power plants within and beyond the EU are used in the calculation model.

Item	IFC World Bank	
	NDA	DA
	mg / Nm^3	
Excess O_2 in dry flue gas	3%	3%
Particulate matter (PM)	50	30
Sulfur dioxide expressed as SO_2	200 - 850	200
Sulfur oxides SO_2 and SO_3 expressed as SO_2	-	-
Nitrogen oxides expressed as NO_2	400	200
Carbon monoxide CO	-	-

Notes: DA: Degraded airshed (Region w ith poor air quality), NDA: Non-degraded airshed

Table 42: World Bank emission limit standards for power plant investments

In non-EU countries a potential investor may be concerned particularly about the following questions:

- According to which rules is grid access approved? Is grid access possible without discrimination?
- Which regulatory rules govern transmission costs for electricity imports into EU?
- According to which rules can transmission capacities for electricity import into EU be booked? Is there access? And without discrimination?
- Are (intergovernmental) connection agreements existing that allow for electricity import into EU?
- Is environmental regulation for new PP investments in non-EU countries a lower or higher burden compared to PP investments within the EU?

Is environmental regulation for new PP investments in non-EU countries a lower or higher burden compared to PP investments within the EU?

4.3 The Decision Making Model

4.3.1 General assumptions

The core task of the study is to compare power plant projects within an EU country and alternatively in a neighbouring non-EU country. Either power plant will supply its entire electricity production to the electricity markets of the respective EU country. The objective is to evaluate which of the two options is from the point of view of the potential investor economically the most favourable. The model for such a decision making process will thus represent the view of an international investor, who decides for the power plant investment to be within or outside the EU.

Since the market offers different prices and revenues for base and peak load power plants within each pair of investment alternatives only power plants with the same load characteristics are compared. This reflects that investment in a base load power plant does not compete with investment in a peak load power plant. For power plants with the same load characteristics, effective electricity prices as well as revenues for both regarded investment alternatives are the same.

As already explained in 4.2.1.5 competitive power plants inside and outside EU shall supply their electricity to the same market. Thus, the plant with the lowest electricity generation costs will have a competitive advantage, Hence, the criterion for economic viability is *electricity generation cos*t. The project with the lowest electricity generation costs will be the preferred investment from the viewpoint of the investor.

Generally, each investor is different with regard to his risk-proclivity but also with regard to his individual assessment, emphasis and expectations of investment risks and success factors. Nevertheless a certain standard investor is defined for this study in order to make the decision process transparent under a given set of assumptions about the investor.

Due to the magnitude of the investment we assume that, the potential investor is characterised to be active internationally with global investment activities in different countries. He has therefore access to international suppliers in the power plant business and is also creditworthy for international creditors. It is thus assumed that the investor will obtain favourable bank credit conditions as described in section 4.2.4.

The discount rate is the weighted average costs of capital (‘WACC’, see section 4.2.4). The investment is financed with an equity share of 30% and 70% bank loans. In our approach, we assume that the investor will obtain the same interest rate for the debt part of the investment regardless of the location of the power plant project.

The actual variable in the WACC is the investor’s expectation on the rate of return on equity (ROE) after tax.

We divide the total expected rate of return on equity in the following components.

- a *risk free return rate* which is identical to the bank interest rate
- a *venture premium* which is typical for power plant investments in EU countries considering the long life cycle and the associated technology risks of the project
- a *country specific risk premium* which is dependent on the specific invest risk situation of the regarded non-EU country. This may also include some credit default insurance.

The model calculates all payment series during the life time of the investment in 2010 Euros, in real terms using as discount rate WACC also in real terms (see 4.2.4). Escalation rates for O&M costs are also in real terms.

Additionally, the investor's expectations on return shall also be independent on taxation, after corporate tax. If taxation in a country is higher, the investor's claim on the return before tax is higher. Since corporate tax rates are different in all countries, also the expected return and thus the WACC will be different for all countries (cf. Table 46).

The investment decision is determined by the comparison of the levelized costs of electricity (LEC) for the pairs of investment options (EU/non-EU). The lower LEC indicates the more competitive is the investment, provided that no qualitative objections are found. Qualitative aspects on the investment decisions, which could not be integrated in the LEC figures, are taken into account via a decision tree (see section 4.3.4).Finally, a ranking of the remaining power plant options is determined for each country according to their LEC.

The model provides also the unique possibility for the calculation of the *break-even point of the LEC* for a power plant in the non-EU country and that in the respective EU country based on the following philosophy: The main benefit for investment outside EU is avoided CO_2 costs. This means, outside the EU the investor can increase his ROE up to a limit where this benefit is balanced by higher returns. If this ROE is not attractive enough for the investor there will be no incentive for investing outside EU: This is done in the model with 'goal seek option' of MS-Excel by changing the 'country specific risk premium' in the WACC.

4.3.2 Levelized electricity costs

The Consultant has developed an integrated user-friendly model in MS-Excel. The model calculates the levelized electricity generation cost (LEC) applying the NPV method based on the following formula:

$$LEC = \frac{CAPEX + \sum_{t-1}^{t=n} \frac{OPEX_t}{(1+i)^t}}{\sum_{t=1}^{t=n} \frac{W_e}{(1+i)^t}} \quad \left[\frac{€}{\text{MWh}}\right]$$

Where:

CAPEX:	Capital expenditures (CAPEX)
$OPEX_t$:	Operating expenses for each year of the life time
W_e:	Electricity production for each year of the life time
i:	Discount rate = WACC
t:	Year of operation
n:	Live time of the project

4.3.3 The structure of the decision making model

The model is designed to calculate up to 5 power plant options for each country inside and outside EU, which are:

- Steam power plant fired with lignite for base load duty
- Steam power plant fired with hard coal for base load duty
- CCGT power plant fired with natural gas for base load
- CCGT power plant fired with natural gas for intermediate load duty
- Open cycle gas turbine power plant for peak duty.

For base load power plants 7,500 full load equivalent operating hours per year are assumed. For intermediate load (CCGT) the assumption is 4,500 full load hours and for the peak load GT 1,250 full load hours. The analysed power plants and their features and technical characteristics are shown in Table 43.

	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
Rated power output, gross	MW	1,100	800	800	800	150
Consumption auxiliaries	%	4.5%	7.4%	1.5%	1.5%	1.0%
Electric efficiency, net	%	43.2%	45.6%	55.3%	55.3%	38.0%
Specific CO_2 emission factors	$g/kWh_{th\ (LCV)}$	404	342	202	202	202
Equivalent operating hours	h / a	7,500	7,500	7,500	4,500	1,250
Lifetime	a	35	35	25	25	25
Operating staff	full time persons	80	70	35	35	20
Specific person years for construction works	full time persons/a	675	675	375	375	150
Construction time	a	5.0	4.0	2.5	2.5	1.0

Table 43: Characterisation of power plants analysed for this study

One file ‘Input’ contains all inputs to the model and hands them over to each country file. In each country file the NPC and LEC are calculated for all feasible power plant options and for all three scenarios A, B and C. The results from the country files are then transmitted to a ‘Results’ file for country-wise comparison and analysis of results.

In the NPC and LEC calculation all kind of costs are taken into account that an investor has to consider in its investment decision. The economic and technical input parameters and the concept of the model are illustrated in Figure 80.

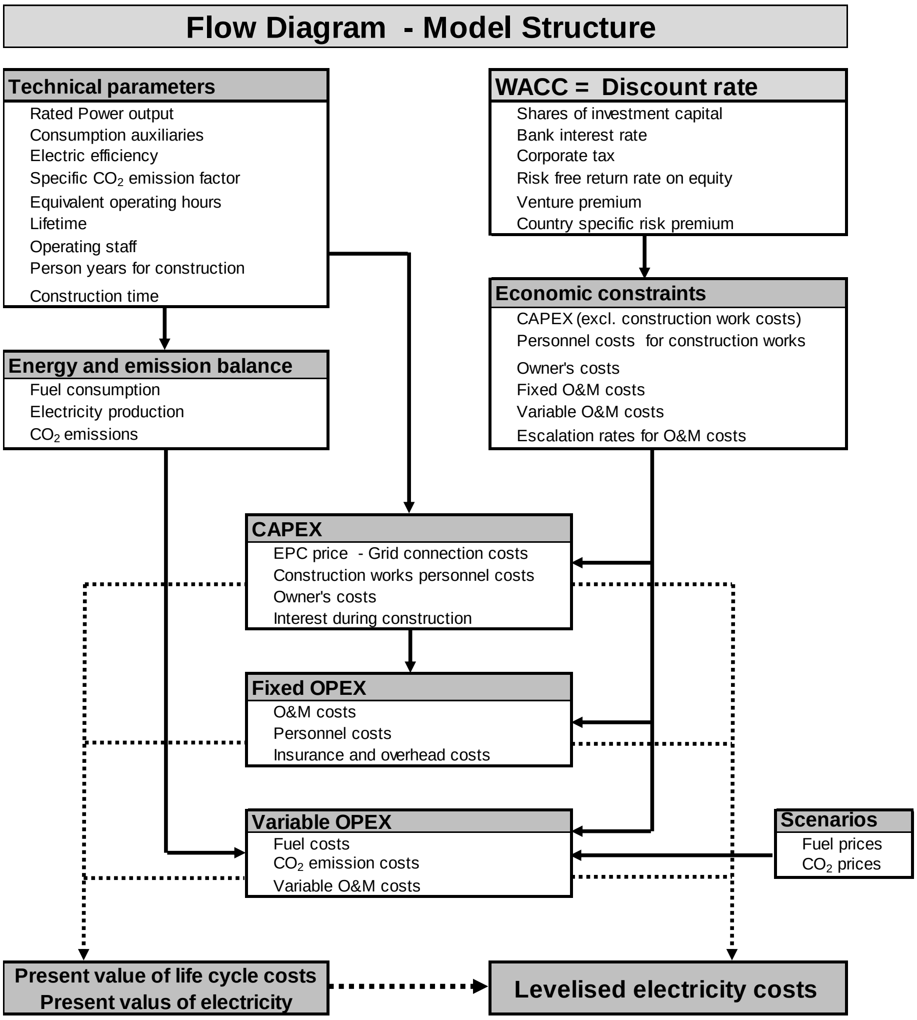


Figure 80: Structure of the decision making model

Technical parameters that are specifying the power plants are mainly those given in Table 43. The main economic parameters for the power plants are listed in Table 44.

	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
Specific CAPEX[1]	€ / kW	1,975	1,720	600	600	450
Owner's costs[2]	%	10%	10%	10%	10%	10%
Fixed O&M[2]	% / a	1.5%	1.5%	1.0%	1.0%	0.5%
Insurance(of equipment)/overhead[2]	% / a	0.5%	0.5%	0.5%	0.5%	0.5%
Variable O&M	€ / MWh$_e$	1.70	1.00	3.00	3.00	4.50

Table 44: Assumed economical parameters by power plant type[5,6]

The CAPEX is broken down in EPC cost, owner’s expenditures, and interest during construction. Additionally, in order to consider possible country-specific differences in construction costs, the costs for construction site personnel are considered separately. For this purpose, country-specific labour costs for construction site staff are considered, as derived from data from [Eurostat_lab] (see Table 45).

[5] without construction works
[6] referred to EPC (inclusive CAPEX for construction)

For the calculation of annual OPEX, also the labour costs for local operating staff are considered to be individual for each country according to typical figures in the energy sector derived from [Eurostat_lab]. Wages as of 2013 (in €(2010)/person/year) are still on quite different levels among the countries considered (see Table 45).

It is assumed, that within the EU cost of labour will assimilate over time, at least until 2050. Accordingly, different escalation rates are underlying in the model in order to arrive at the same level in 2050.

country	wages escalation operating staff %/a real	annual costs for wages construction €/pers./a 2013	annual costs for wages operating staff €/pers./a 2013	escalation of OPEX %/a real	risk premium after tax %/a on top of infl.	corporate tax %/a
BG	5.6%	5,542	14,638	1.0%	0.0%	10%
EE	4.8%	16,102	19,098	1.0%	0.0%	21%
ES	0.8%	35,995	81,930	1.0%	0.0%	30%
FI	2.0%	52,778	51,875	1.0%	0.0%	25%
GR	1.0%	28,788	74,967	1.0%	0.0%	20%
HU	3.8%	11,869	27,259	1.0%	0.0%	19%
IT	1.3%	36,420	66,447	1.0%	0.0%	28%
LT	5.1%	10,688	17,360	1.0%	0.0%	15%
LV	5.1%	10,663	17,103	1.0%	0.0%	15%
PL	4.2%	13,818	23,563	1.0%	0.0%	19%
RO	5.1%	7,337	17,038	1.0%	0.0%	16%
SI	2.7%	22,284	40,296	1.0%	0.0%	20%
SK	4.1%	14,752	24,804	1.0%	0.0%	19%

Table 45: Country-specific model inputs

Apart from labour costs for power plant operation, further parts of the fixed OPEX concern fixed O&M and overhead and insurance costs, which are given as a rate on the EPC price (cf. Table 44). Variable OPEX includes mainly fuel costs and CO_2 costs, derived from scenario-specific fuel prices and ETS prices. Additionally also variable O&M expenses are considered, given as specific values in €/MWh_e. They are particularly high for gas turbines which require more O&M efforts than steam turbines.

Based on all the above the model calculates the OPEX and the present values of all payment series during the lifetime of the project and finally the LEC.

The LEC are calculated in €/MWh as composite generation cost including all costs items and as marginal cost including only the variable cost items.

In brief, the model does the following operations:

- Power and energy balance
- The *LE*C is the present value of the total costs divided with the present value of the electricity production during the life time.
- Discounting time is commissioning year of the power plant.

- The calculation is conducted in real terms based on 2010 Euros.
- The CAPEX includes also interest during construction
- Each item of the OPEX considers also escalation in real terms, or respectively the assumed real price paths for ETS prices and fuel prices.
- The LEC are calculated as composite generation cost including all costs items and as marginal cost including only the variable cost items.

All country-specific inputs to the model are marked in orange in Figure 80 and listed in Table 45 (apart from the scenario specific inputs which are described in 5.1 and in Annex I and Annex II). Interestingly to see in Table 45 is the difference in the corporate tax rates applied among the regarded EU countries, which range from 10% in Bulgaria to 30% in Spain. Tax rates crucially increase the cost of capital, as becomes visible from Table 46.

	Unit	$WACC_n$ after tax nominal	$WACC_n$ before tax nominal	$WACC_r$ before tax on top of infl.
BG - Bulgaria	% / a	6.76 %/a	7.12 %/a	4.61 %/a
EE - Estonia	% / a	6.76 %/a	7.63 %/a	5.11 %/a
ES - Espania	% / a	6.76 %/a	8.16 %/a	5.63 %/a
FI - Finland	% / a	6.76 %/a	7.82 %/a	5.29 %/a
GR - Greece	% / a	6.76 %/a	7.58 %/a	5.05 %/a
HU - Hungary	% / a	6.76 %/a	7.53 %/a	5.01 %/a
IT - Italy	% / a	6.76 %/a	8.00 %/a	5.47 %/a
LT - Lithuania	% / a	6.76 %/a	7.33 %/a	4.82 %/a
LV - Latvia	% / a	6.76 %/a	7.33 %/a	4.82 %/a
PL - Poland	% / a	6.76 %/a	7.53 %/a	5.01 %/a
RO - Romania	% / a	6.76 %/a	7.38 %/a	4.86 %/a
SI - Slovenia	% / a	6.76 %/a	7.58 %/a	5.05 %/a
SK - Slovakia	% / a	6.76 %/a	7.53 %/a	5.01 %/a
Average	% / a	6.76 %/a	7.58 %/a	5.06 %/a

Table 46: Weighted average cost of capital (WACC) for all analysed countries

4.3.4 Decision tree for non-monetary tangible factors and risks

With levelized costs of electricity all economically quantifiable impacts on investment decisions are evaluated. Even risks which are often hard to quantify can be approximately integrated quantitatively via estimated appropriate risk premiums.

However, many factors that impact an investment decision for a new power plant can hardly be expressed in monetary terms. This may particularly concern technical preconditions for an investment, but also simple facts, i.e. the local unavailability of lignite fuel. Such factors often represent criterions that would lead to the exclusion of investment opportunities, independent on its microeconomic analysis.

For the inclusion of such factors a decision tree is set up. With the decision tree all those investment options shall be filtered off that are either technically not feasible or are clearly far from being a viable option or competitively realisable. The following factors are considered and applied in the decision tree:

- feasible connectivity to ENTSO-E network
- availability of fuel, particularly of lignite
- politically caused investment obstacles

Feasible connectivity to ENTSO-E network
Power plants outside EU must be interconnected to the ENTSO-E network. The feasibility of a connection of a power plant in a non-EU country to the grid of a neighboured EU country is thoroughly described in section 4.2.6.2.

The preconditions depend on the grid features of the EU country on the one hand and on the grid features of the non-EU country on the other hand. Additionally, the distance of a transmission line as well as the geographic conditions determine which type of power system coupling could be a feasible option, if any at all.

Interconnections usually involve high capital expenditures and the feasibility depends on the specific case. Furthermore, in many cases, interconnection between countries inside and outside the ENTSO-E grid may only be feasible in combination with dedicated grid enhancement measures in the regarded EU country as well as within the ENTSO-E grid.

The cost for interconnection and reinforcement of the grid are in most case prohibitively high and have an adverse impact on the economic viability of the investment.

Interconnections overseas such like from North Africa to South Europe or from Balkan countries to Italy are heavily dependent on the distance to overcome. Apart from the Strait of Gibraltar and perhaps apart from the shortest trace between Albania and Italy, all other regarded over-sea connections require HVDC coupling, causing additional crucial capital cost expenses. Those costs are taken into account in the model. But with the decision tree those transmission options are excluded, for which a priori a realistic technical solution is clearly not achievable.

Additionally, the number of asynchronous couplings to a synchronous European grid zone may be a factor which influences the project feasibility. This is because the balance of the whole system is heavily impacted by each HVDC link and particularly by the interaction of the links with the HVAC networks. That means for the model that according to a priority ranking only some of the theoretically feasible links are opted in for the model.

Concerning such rankings the [TYNDP 2012] released recently in July 2012 by ENTSO-E is of great importance. It covers different 20-years-scenarios for the development of the ENTSO-E grid. Each scenario displays a valid generation adequacy assessment, encompassing jointly all foreseeable futures and matching EU 202020 targets (see [SOAF 2012]). [TYNDP

2012] also proposes generic planning standards that shall hold for the future development of the network. Also an iterative analysis of market studies and network modelling was performed that indicates not only technical but also economic priorities.

Due to the role of the TYNDP within the EU policy and for the official network development planning, the TYNDP has highest relevance for the real expectable future grid development. Depending on the analysis of the [TYNDP 2012] some of the regarded interconnections are thus either highlighted or excluded within the decision tree (see section 6.1.1.2).

Availability of fuel
Fuel availability plays particularly a role for the case of lignite. Due to its relatively high transport cost, the use of lignite is economically feasible only for power plants in the neighbourhood of lignite deposits. In the following EU countries are currently lignite power plants in operation: Bulgaria, Greece, Hungary, Poland, Romania, Slovenia, Slovakia and Spain. As mentioned below, however in Spain no new coal power plant at all is considered to be feasible according to the political plan. Countries where new lignite power plants are feasible are therefore regarded:

Bulgaria, Greece, Hungary, Poland, Romania, Slovenia, Slovakia

Also the availability of natural gas can be a critical factor that may exclude in some countries a feasible natural gas power plant project. Important for the power plant investor is to have natural gas pipeline capacities available that are large enough to transport enough gas amounts to the power plant and that are moreover not yet contracted for the delivery of other consumers. Thus the available reserves of free natural gas pipeline capacities is be a criterion in the decision tree.

In countries with ambient natural gas reserves, such as Algeria, gas delivery for a power plant may not be a problem, in general. However in countries with only very little natural gas reserves like in Morocco an affordable gas supply at sufficient volumes may be an insurmountable obstacle for a natural gas power plant venture. The capital costs for installing a pipeline over very long distances dedicated for the supply of the power plant are usually too large for the whole power plant project, let alone the additional planning and development lead times for the pipeline. The same holds for LNG ports, if they are not available anyway for other large natural gas customers as well.

Political exclusion of certain power plant technologies
There are countries in which certain power plant technologies have no chance for realisation of new projects. One example is Spain.

Spain’s policy in respect to power generation is determined by the Ministry of Tourism and Economy’s report ‘Planificación de los Sectores de Electricidad y Gas 2002-2011’ (Electricity and Gas Sector Planning) from 2002 and its revision from 2006 [SGDE 2006]. It includes a plan about the future power plant capacities to be installed in Spain. For new power plants the plan exclusively refers to installations of new CCGTs. Only one modernization of the coal power plant in As Pontes was included. Apart from this, Spain focuses completely on new natural gas fired power plants. This is also reflected in the Spanish NAP, where emission allocation for coal plants was much more restrictive, thus promoting again power plants on basis of natural gas. Spanish government also guaranteed to keep on this strategy for the time further after the second allocation plan from 2008-2012, thus giving the industry a basis for long-term planning security. Against this background, no new coal power plants in Spain are regarded to be feasible.

With the decision tree such cases of political exclusion of certain power plant technologies in the countries considered are filtered off.
Further political investment obstacles could arise indirectly, for instance from the ETS. Investors may not like to invest in a non-EU country in order to avoid CO_2 costs, when the regarded EU country has the real perspective to become soon a member of the European Union that will take part into the ETS. This could for instance concern power plant investments in Croatia.

Also the investment for a synchronous interconnection within the IPS/UPS system from Russia to a Baltic country may not be triggered since for each project a transmission license from the national regulatory body and from EC as well is needed, as is required by ENTSO-E network code. Moreover, the long term political goal of the three Baltic countries Estonia, Latvia and Lithuania to decouple from the IPS/UPS system poses the risk for Russian-Baltic cross-border transmission investments to become redundant.

Furthermore, grid access policy in non-EU countries (cf. section 4.2.8) can be different compared to EU countries where power plant investors shall generally obtain a non-discriminatory grid access. The decision tree will thus exclude options which are not viable due to missing security for the investor to obtain non-discriminatory grid access.

4.4 Conclusions

An integrated user-friendly model (MS Excel) was developed for this study. The model calculates the levelized electricity generation cost (LEC) applying the NPV. In the NPC and LEC calculation all kind of costs are taken into account that an investor has to consider in its investment decision. All cost series are calculated in real terms and discounted with the WACC.

Five power plant options are investigated pair-wise inside and outside of EU countries, namely: a lignite power plant (base load), a hard coal power plant (base load), two CCGTs (one for base load and one for intermediate load) and a gas turbine (peak load). Economic and non-economic investment decision factors are analysed from the investor’s point of view and are integrated into the model.

The project with the pair-wise lowest electricity generation costs is the preferred investment from the viewpoint of the investor. LEC are calculated from present values of all cost components divided with the present value of the produced electricity.

The LEC are calculated in €/MWh as composite generation cost including all costs items and as marginal cost including only the variable cost items.

Uncertainty about the future range of cost developments is investigated with a scenario analysis (see section 5.1). Other economic factors such as prices of power plants, OPEX components and costs of capital are integrated into a determination of levelized composite costs of electricity. Since investment in a base load power plant does not compete with investment in a peak load power plant, electricity prices do not matter in the pair-wise comparison of investment options provided that power plants supplying for the same price band (i.e. base load/peak load) are compared.

Non-economic investment factors concern mainly technically and politically originating investment risks, as far as they cannot be hedged by the investor. Investment risks are covered by the model either via

- differentiated risk premiums,
- scenario and sensitivity analysis and
- a decision tree that excludes infeasible investment options.

With regard to risk premiums an adequate level of ROI is considered in the WACC by dividing the imputed return rate on equity into

- a ***risk free return rate*** which is identical to the bank interest,
- a ***venture premium*** which is typical for power plant investments in EU countries, and into
- a further ***risk premium*** which is dependent on the specific invest risk situation of the regarded non-EU country.

Scenario analysis concerns consistent fuel and CO_2 price. Infeasibilities for investment options as treated via the decision tree concern mainly

- the available connectivity options from outside EU to the ENTSO-E network
- local availability of fuel, particularly of lignite
- politically caused investment obstacles
  (e.g. no coal power plants in Spain).

5. Analysis of Investment Decisions in EU Countries

5.1 Scenarios

For studying the impact of full-auctioning of CO_2 emission allowances on the investment decisions for power plant installations, three different carbon constraint scenarios are taken into account within this study. In accordance with the specifications for the project as given by the European Commission, the following three scenarios concerning EU carbon constraints are analysed:

A) 20% greenhouse gas reduction by 2020 compared to 1990

B) 25% greenhouse gas reduction by 2020 compared to 1990 and 80% by 2050

C) 30% greenhouse gas reduction by 2020 compared to 1990 and 80% by 2050

These three scenarios are hitherto accordingly referred to as Scenario A, B and C in this report. ***Scenario A*** conforms to the ***20% EU emission reduction target*** as established with Directive [2009/29/EC] and Decision [406/2009/EC]. It represents the confirmed commitment of the Community to reduce the EU's overall greenhouse gas emissions by at least 20 % below 1990 levels by 2020. Since the EU policy to reach this target is already adopted, Scenario A is carried out in the manner of a ***reference scenario*** of unchanged policies.

Scenario A grounds on the also so-called reference scenario as described in [SEC(2011) 288 final]. It is based on already implemented EU and national policies with a cut-off date in March 2010. Thus scenario A not only implies to reach the ETS target to achieve the 20% reduction target in 2020. But it furthermore assumes full implementation of the non-ETS and renewable energy legislations up to this point in time, such as the Effort Sharing Decision [406/2009/EC] and Directive [2009/28/EC] that have set legally binding national targets for 2020. Apart from that it is consistent with the reference scenario until 2030 as published in [EU Trends], which has been used, amongst others, in the analysis of options to move beyond 20% GHG emission reductions (see also SEC(2010) 650).

However, an EU target of 20% by 2020 is seen just as a first step to put emissions onto a path where developed countries will need to cut emissions by 80-95% in order to keep global temperature increase below 2°C compared to pre-industrial levels. The Copenhagen summit failed to achieve the goal of a full, binding international agreement to tackle the 2°C goal globally. Nevertheless the EU is considering higher emission reduction targets for the Community by 2020 provided that carbon leakage is avoided. ***Carbon leakage*** defines the risk that would occur if, for reasons of costs related to climate policies, businesses transferred production to other countries which have laxer constraints on GHG emissions and that would thus in overall lead to an increase in overall emissions compared to the situation without these climate policy related costs.

Thus, the Commission communicated an ‘Analysis of options to move beyond 20% greenhouse gas emission reductions and assessing the risk of carbon leakage’ [COM(2010) 265 final]. In the associated ‘background information and analysis’ document [SEC(2010) 650 part II] it is concluded that it would require EU emissions rather to be at around ***-25% by 2020*** compared to 1990 in order to be on an EU emission trajectory that is compatible with a 2°C global emission pathway until 2050. This requirement is represented with ***Scenario B***. In Scenario B the EU reaches also its ***80% emission reduction goal in 2050***, although it acts in a global framework where other countries do not follow the global action scenario (‘***fragmented action***’).

In the contrary case of a genuine global effort towards the 2°C target the EU adopted additionally to its 20% unilateral emission reduction commitment a further commitment to move to a 30% emission cut. Such a framework of ***global action*** is represented with ***Scenario C***. In this scenario it is assumed that a climate protection strategy is pursued globally that leads to a reduction of global emissions of 50% by 2050 compared to 1990. The EU would not only fulfil its ***80% emission reduction goal in 2050*** but would already achieve ***30% emission reduction by 2020***.

The three scenarios A, B and C base on EC documents that accrued around the development of the EU Energy Roadmap 2050. Most important document for this report is the impact assessment outlined in the Commission staff working document [SEC(2011) 288 final] ‘A Roadmap for moving to a competitive low carbon economy in 2050’. Scenarios outlined in [SEC(2011) 288 final] are based on a E3 (energy, economy, environment) modelling framework that applies different coherent models including PRIMES, PROMETHEUS, GAINS and GEM-E3 for the EU energy system modelling (for more details see [SEC(2011) 288 final]). From this modelling exercise consistent price paths for CO_2 prices and fuel prices were derived, that are used in our study for representing Scenario A, B and C. For this purpose the following scenarios from document [SEC(2011) 288 final] are assigned to the scenarios of this report, that have similar assumptions and preconditions:

This report Scenario name	**SEC(2011) 288 final** Scenario name
A	Reference Scenario
B	Effect Techn. (frag. action, ref. fossil f. prices)
C	Effect Techn. (glob. action, low fossil f. prices)

Table 47: The scenarios used in this report and their EU Scenario counterparts

In the following the three scenarios and their assumptions regarding CO_2 prices and fuel prices are described in more details.

5.1.1 CO_2 prices

The development of CO_2 prices of the three scenarios is shown in Figure 81. Depending on whether there is a long term reduction goal for 2050 (as in scenarios B and C) or not (as in Scenario A), projected price paths are quite differing, particularly after the year 2035. CO_2 prices in Scenario A are almost stagnating at a relatively low level of about 50 €(2010) / t CO_2 from 2035 onwards in Scenario A (cf. Table 48). This corresponds to the only low GHG reduction of 39% (compared to 1990) achieved by 2050 in this Scenario A (cf. Table 49).

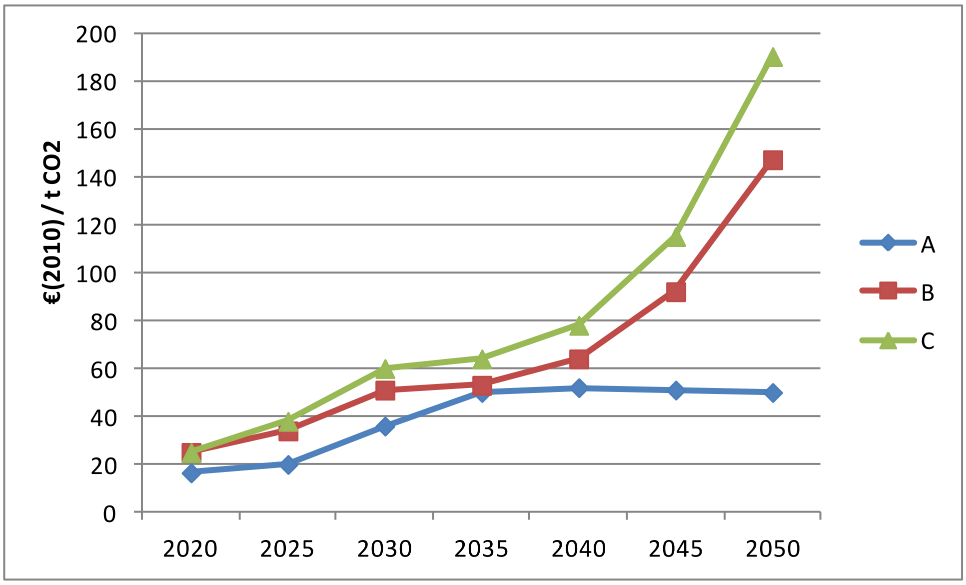


Figure 81: CO_2 prices in the three scenarios (for derivation cf. description above)

From the decarbonisation scenarios B and C, the one with fragmented action shows lower CO_2 prices than the one where a global climate strategy is pursued. The fossil fuel prices are the main reason for this: In a world with global climate action, fossil fuel demand is significantly reduced and fossil fuel prices relax accordingly. If other countries than the EU do not follow a global action scenario (i.e. fragmented action, as in Scenario B), global fossil fuel prices are assumed to be at much higher levels (see section 5.1.2). Thus in general, in the scenarios high CO_2 prices come with low fossil fuel prices and vice versa. This is consistent, because high efforts for climate protection put pressure on fossil fuel consumption and thus on fossil fuel prices.

Higher fossil fuel prices support the shift away from fossil fuel use and help thus naturally to achieve the emission reduction goals at lower CO_2 prices. In other words: The cases of global action or fragmented action determine, whether the EU has to pay its CO_2 emission reduction achievements rather via increased fossil fuel price levels (fragmented action) than via higher CO_2 prices (global action). The overall impact on the economy is however different nevertheless, as is explained in [SEC(2011) 288 final].

Scenario	CO_2 price (€2010/t CO2)						
	2020	2025	2030	2035	2040	2045	2050
A	16.57	20.08	36.14	50.20	52.21	51.20	50.20
B	25.10	34.14	51.20	53.21	64.26	92.37	147.59
C	25.10	38.15	60.24	64.26	78.31	115.46	190.76

Table 48: CO_2 prices in the three scenarios (for derivation cf. description above)

Scenario	Total GHG reduction in the EU vs. 1990				
	2005	2020	2030	2040	2050
A	-7%	-22%	-29%	-36%	-39%
B	-7%	-26%	-41%	-61%	-80%
C	-7%	-25%	-40%	-62%	-80%

Table 49: Total GHG reduction in the EU in the three scenarios (for derivation cf. description above)

5.1.2 Fossil fuel prices

Also the fossil fuel prices in our three scenarios are referring to the associated EU scenarios from [SEC(2011) 288 final] as assigned in Table 47. Natural gas and coal are the main relevant fuel types for power plants and are the only fuel types assumed for the power plant types that are analysed with this study (cf. section 4.3.2).

[SEC(2011) 288 final] contains explicit fuel price figures only for crude oil. However in the energy roadmap 2050 communicated by the Commission in December 2011 [SEC(2011) 1565 final, part I], there are natural gas and coal prices mentioned for the reference scenario. The reference scenario in this document is designed as an updated version of the reference scenario from [SEC(2011) 288 final]. Thus, those fossil fuel prices are used for our Scenario A.

In part II of the energy roadmap [SEC(2011) 1565 final, part II], global fossil fuel prices for the decarbonisation scenarios are depicted in Figure 18 of that document. The decarbonisation scenarios are based on 'global climate action' fossil fuel price trajectories. Accordingly these updated price paths are used for representing our Scenario C.

Fossil fuel prices for Scenario B are derived from the oil price path of the fragmented action scenario in [SEC(2011) 288 final] and its relation to the reference oil price. The obtained relation is used for projecting an according fragmented action oil price path out of the reference scenario from document [SEC(2011) 1565 final]. With the oil-to-gas and gas-to-coal price relations of the reference scenario of [SEC(2011) 1565 final, part I] the belonging gas and coal price paths for the case of fragmented action are derived.

The obtained natural gas price and coal price development (indexed 2010 = 100%) for the three scenarios A, B and C is shown in Figure 82 and in Figure 83. As becomes visible, fragmented action (Scenario B) brings fossil fuel prices down compared to the reference

Scenario A, however much less than in the case of global climate action (Scenario C). This correlates with gradually higher downward pressure on fossil fuel markets, the higher the global decarbonisation efforts are pursued.

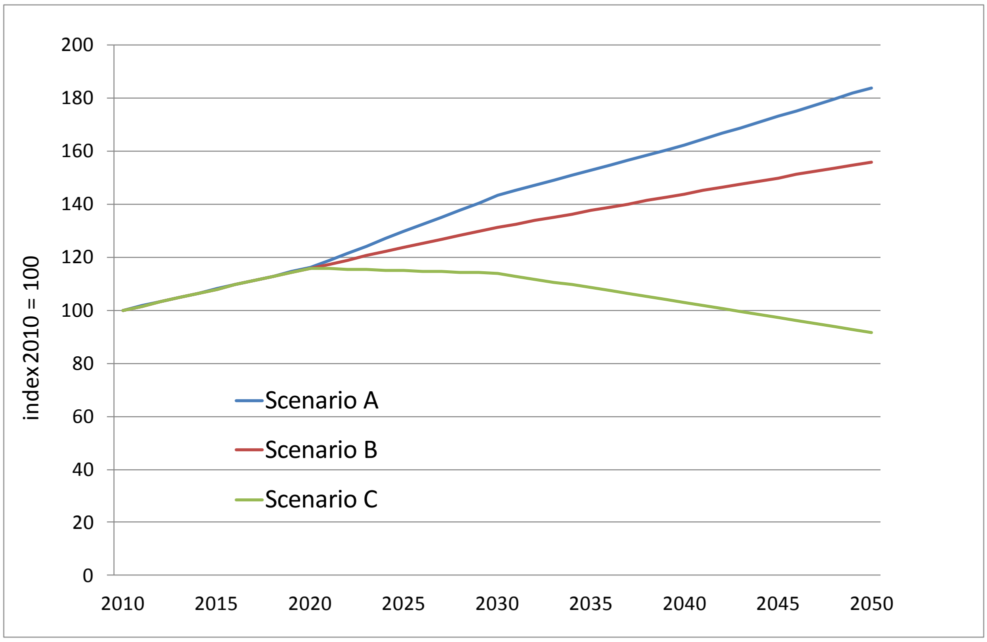


Figure 82: Natural gas price development for the three scenarios

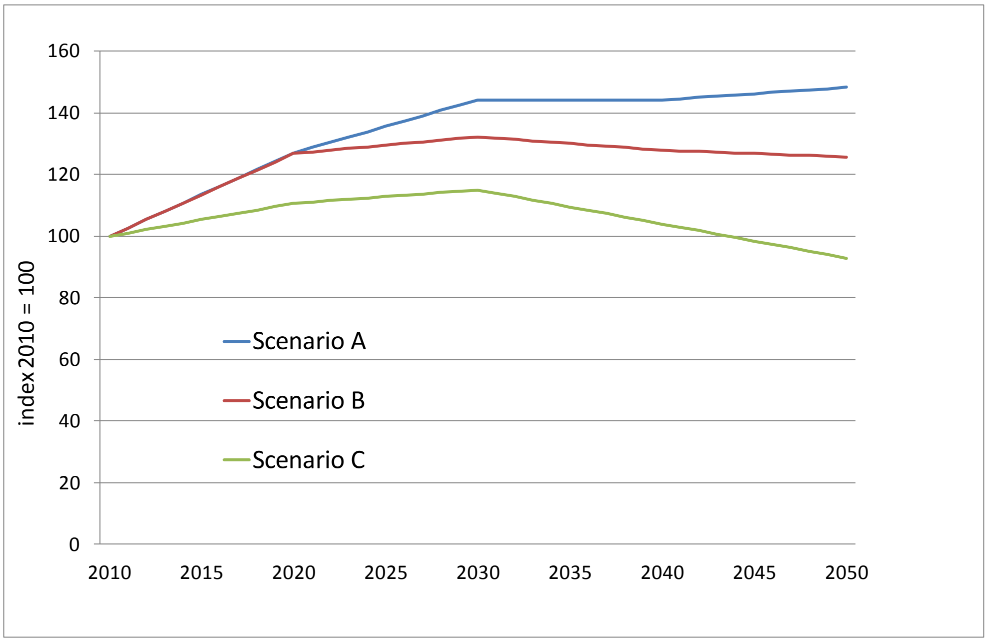


Figure 83: Coal price development for the three scenarios

From these indexed global fossil fuel price trajectories, national price paths faced by power plant operators for natural gas, hard coal and - if applicable - for lignite as well are derived. Thereby the future price development of lignite is assumed to follow like hard coal the price index for coal as shown above. The reasoning is, that lignite power plants are assumed to compete most with hard coal power plants. Since there is no marketplace and market price for lignite, lignite prices are actually represented by extraction costs plus possible opportunity costs. Due to relatively high transport costs, lignite power plants are only feasible at locations where enough lignite resources for combustion in power plants are available. Among the investigated EU countries this is the case in Bulgaria, Greece, Hungary, Poland, Romania, Slovakia and Slovenia. In the following EU countries new lignite power plants are not feasible: Estonia, Finland, Lithuania, Latvia, Italy and Spain.

The global fossil fuel prices are used for describing the future price trends on the fuel markets. However, as absolute values valid for the starting year 2010 no global prices are used. Instead prices faced by power plant operators in the investigated EU countries are taken. The regional price levels are derived from mainly two sources, [IEA] and [Eurostat_gas].

[IEA] lists for some countries annual mean 'natural gas prices for electricity generation (ex-tax)' for the years up to 2010. If for some countries those data were not available, data for 'natural gas prices for industry' were taken and adjusted accordingly to represent prices faced by power plant operators. Adjustment was also done by comparison and reconciliation with data from [Eurostat_gas]. [Eurostat_gas] lists also 'natural gas prices for industry' for different consumer specifications, with consumers drawing less or more than 4,000,000 GJ/a.

Gas price values from the years 2009 and 2010 were averaged in order to balance singular outlier values. All gas prices referring to the gross calorific value of natural gas are factorised by 1.11 to obtain prices for net calorific value (NCV). The finally obtained natural gas prices for 2010 in the different EU countries are shown in Figure 84. They are assumed to represent prices for a CCGT operated in intermediate load at 4,500 full load hours per year.

In contrast to all other fuel prices, the 2010 natural gas price levels for Romania and Poland shown in Figure 84 and Table 50 were not derived directly from [IEA] and [Eurostat_gas] but were corrected according to the market value principle. Natural gas prices derived from [IEA] and [Eurostat_gas] for these two countries seemed to be far too low and not sustainable from a long term market perspective. Such low price levels will thus not be used for long term investment considerations. We adjusted the natural gas price levels in both countries according to the market value principle. The adjusted price levels were derived by comparing the levelized electricity costs (LEC) of competing fossil fuel fired power plants in those countries, assuming no carbon costs is accruing for the power plants. This principle guarantees that coal fired power plants will at least in base load and without emission trading compete in these countries with natural gas fired power plants.

Natural gas prices for power plants are usually dependent on the volumes of natural gas withdrawn from the gas network. The higher the delivery capacity, the lower the fees for the usage of the gas transport system. This is expressed in an estimated fee of 6,500 €/$MW_{t,NCV}$. For natural gas power plants with other than 4,500 annual full load hours, the natural gas prices shown in Figure 84 and Table 50 are adjusted accordingly within the model.

Also for hard coal, as far as available annual figures from [IEA] for 'steam coal prices for electricity generation' are taken. This is the case for Finland, Italy, Poland and Spain. For other countries, the cross-border price for hard coal for the German market for 2010 from [VDKI] is taken as a proxy, which is comparable to the cif ARA price achievable at most important ports of debarkation in Europe. On this, 4€/t for cargo handling and discharge and 6€/t for typical inland transport fee are put on top. For lignite, an effective specific fuel cost value of 5.5 €/$MWh_{t,NCV}$ is applied for 2010 based on Fichtner database.

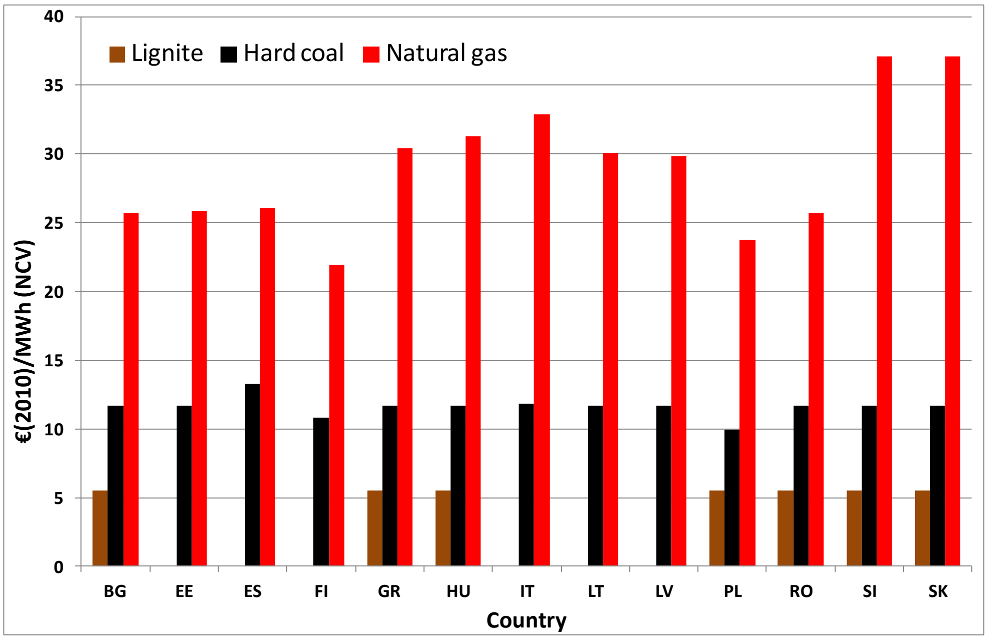


Figure 84: Fuel prices for power plants in 2010 in €(2010) / $MWh_{t,\ NCV}$

Country	Fuel price 2010 in €(2010)/MWh_{NCV}		
	Lignite	Hard coal	Natural gas
BG	5.50	11.71	25.69
EE	N.A.	11.71	25.85
ES	N.A.	13.28	26.09
FI	N.A.	10.85	21.95
GR	5.50	11.71	30.41
HU	5.50	11.71	31.32
IT	N.A.	11.86	32.91
LT	N.A.	11.71	30.07
LV	N.A.	11.71	29.86
PL	5.50	9.95	23.75
RO	5.50	11.71	25.69
SI	5.50	11.71	37.12
SK	5.50	11.71	37.07

Table 50: Fuel prices for power plants in 2010 in €(2010) / $MWh_{t, NCV}$

All country-specific fuel prices in 2010 are compared in Table 50. Price levels are particularly varying among countries for natural gas. Highest gas prices are observed in Slovenia and Slovakia, whereas lowest prices are achieved for natural gas delivery in Finland. Most natural gas prices are however within a corridor of about 25 to 37 €(2010)/$MWh_{t,NCV}$ (cf. Table 50). This is compared to a mean price of about 11.6 €(2010)/$MWh_{t,NCV}$ for hard coal and about half this value for lignite (5.5 €(2010)/$MWh_{t,NCV}$).

Based on the country-specific fuel price levels from Table 50 and on the scenario-specific global fuel price developments as outlined in Figure 82 and Figure 83, for each country the annual fuel price development is projected until 2050 and included in the decision making model. If the lifetime of power plants should exceed 2050, a stagnating price level (in real terms) is assumed for the years after 2050. The same prolongation after 2050 is applied to CO_2 prices.

5.1.3 Levelized scenario prices

For the use in the model all fuel price path and CO_2 price path as derived for the different scenarios are levelized for each power plant and for each country. This is done by discounting them among the lifetime of the concerning power plant and transferring the net present values into annuities. Since the lifetimes of the regarded power plants are varying, also the levelized prices are varying by power plant type. And since the imputed discount rates are different for each country (cf. Table 46), the levelized prices are also varying by country.

The levelized prices can be seen as a constant price expressed in present Euro value terms, which is equivalent to the actual price path over the power plant lifetime. Annex I and Annex II show the levelized CO_2 prices and levelized fuel prices for the three scenarios by country and power plant type.

5.2 Change from 2nd to 3rd Emission Trading Period

In this section the changes from the second to the third trading phase of the ETS are explained, as far as they concern investors for new power plants in the regarded EU countries.

5.2.1 Free allocations of certificates in the second ETS period

Within the 2nd ETS trading period from 2008 to 2012 there are two ways of how to obtain emission allowances (EUAs) that are required for a new power plant: Some parts of the EUAs may be allocated to the power plant according to the NAP of the regarded country. And the remaining EUAs need to be acquired either via auctioning or on the ETS market at prevailing CO_2 prices. In the case of over-allocation the surplus of EUAs could be sold at the CO_2 price.

Since the NAPs of the second trading period of the EU countries are different, the allocation quota can be quite different for each regarded country, even though for the same type of power plant. For this study the emission certificate allocations for new power plants are analysed in those countries, for which the allocation equations and their parameters were available from [ISI]. These are the following countries: Bulgaria, Estonia, Finland, Italy, Lithuania, Latvia, Slovak Republic and Slovenia.

The parameterisation of allocated emissions is constant for each single year within the 2nd ETS period (2008-2012), apart from Italy where the fuel factors change within the ETS period. Thus, for Italy the allocation as it is valid for 2012 is analysed. The resulting free allocation of certificates is shown in Table 51. For better comparison the allocated certificates are related to the net electricity generation of the plants, i.e. are given as ‘specific free allocation’ per generated kWhe. The figures are to be viewed against the background of the actual CO_2 emissions, for which in the third trading period certificates will have to be fully auctioned. Those are given in the second row of Table 51 as specific CO_2 emissions per net electricity generation.

	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
Specific CO_2 emission factor (fuel)	g / kWh_t	404	342	202	202	202
CO_2 emissions per kWh_e	g / kWh_e	935	750	365	365	532
Specific free allocations						
BG	g / kWh_e	947	778	353	353	352
EE	g / kWh_e	N.A.	750	365	365	532
FI	g / kWh_e	N.A.	155	90	150	780
IT	g / kWh_e	N.A.	608	220	367	1,316
LT	g / kWh_e	N.A.	360	338	564	2,020
LV	g / kWh_e	N.A.	786	369	369	534
SI	g / kWh_e	330	340	320	320	318
SK	g / kWh_e	935	750	365	365	532

Table 51: Free allocations of certificates in the 2nd ETS period by country and power plant (derived from [ISI])

The power plant operator must acquire the difference between actual CO_2 emissions of the plant and the free allocated allowances. This gap is shown in Table 52 as%age of the plant's actual emissions. A negative figure in Table 52 represents a negative deficit which in fact is a surplus of allocated allowances. It reveals at a first glance how strong the endowment with the required CO_2 certificates is varying by power plant type, but also by country. In countries like Bulgaria, Estonia, Latvia and Slovakia almost no certificate deficits are remaining. Allocation rules in other countries, like for instance Finland, are rather strict.

In some cases however, significant over-allocations of allowances is revealed for new power plants that are built within the second trading phase. Huge negative deficits, i.e. endowment with surplus certificates can be observed particularly for the gas turbine power plants, and this particularly in Lithuania and Italy.

Percentual certificate deficit (after free allocations)	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG	%	-1%	-4%	3%	3%	34%
EE	%	0%	0%	0%	0%	0%
FI	%	N.A.	79%	75%	59%	-47%
IT	%	N.A.	19%	40%	-1%	-148%
LT	%	N.A.	52%	7%	-54%	-280%
LV	%	N.A.	-5%	-1%	-1%	0%
SI	%	65%	55%	12%	12%	40%
SK	%	0%	0%	0%	0%	0%

Table 52: Certificate deficit after allocation (in%age of emissions)

Lithuania applies a uniform benchmark of 2,500 t/MW_e per capacity. Thus peak load power plants are greatly fostered compared to base load plants. Apart from Lithuania also Slovenia applies a uniform benchmark of 350 t/GWh_e for all new power plants but relates it to the projected (gross) electricity generation of each power plant, which for our study is assumed to be identical to the actual electricity generation. Thus the difference of the allocation gaps among the power plants in Slovenia solely reflects different efficiencies of the plants and different specific CO_2 emission factors for the used fuels. Accordingly, CCGTs come off best in relative CO_2 allocation in Slovenia.

All other countries use benchmarks that are differentiated in different ways and somehow related to the output of the power plant, which is either capacity or generated electricity. The only exception is Estonia, where the allocation basis is not output based, but based on projected emissions. Consequently, the certificate deficit in Estonia is zero. It is also zero in Slovakia, but the way of allocation is different. In Slovakia the specific emission value in g/kWh_e as well as the electricity generation are projected, which also leads theoretically to the certificate allocation for exactly actual emissions.

5.2.2 Microeconomic effects from change to full auctioning

The microeconomic effects from full auctioning are compared to the situation with the NAPs in the second ETS phase. In order to determine the microeconomic effects of the NAPs on new power plant investments, the levelized CO_2 costs of electricity are calculated with the decision making model for all power plants in the regarded EU countries (cf. Table 53, Table 54 and Table 55). For these calculations the CO_2 price paths of the three scenarios (cf. section 5.1.1 and Annex I) are applied in order to demonstrate their effect on electricity costs. This effect is expected to have no relevance for electricity prices, because the market value of CO_2 allowances is already integrated into electricity prices since the commencement of CO_2 emission trading (cf. section 4.2.1.2). For this study, only the microeconomic effects concerning the electricity costs from the view of a power plant investor are focused. The change of the specific costs due to introduction of full auctioning reflects the amount of windfall profits that were coming in the 2nd ETS with gratis allocated emission rights.

The resulting ***CO_2 costs of electricity*** represent the additional costs on electricity generation from a new power plant due to acquisition of the remaining certificate deficit (cf. Table 52). The certificate deficit has to be purchased over the whole lifetime of the plant at the prevailing CO_2 prices in each year.

CO_2 price levels are generally increasing from Scenario A to Scenario C. Accordingly, also levelized CO_2 costs (or revenues) from purchase (or selling) of the remaining certificate deficit (or surplus) are highest in Scenario C. Again here, negative CO_2 costs mean revenues for the operators per generated MWh_e. Those can be rather high. As for gas turbines in Lithuania they amount to about 35 to 53 €/MWh_e additional income, depending on the regarded scenario. In general, new gas fired power plants - particularly gas turbines - were less burdened by the 2^{nd} ETS period than new coal fired power plants. This is generally in alignment with the polluter pays principle.

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	-0,32	-0,77	0,29	0,29	4,31
EE - Estonia	€ / MWh_e	N.A.	0,00	0,00	0,00	0,00
FI - Finland	€ / MWh_e	N.A.	16,17	6,46	5,06	-5,82
IT - Italy	€ / MWh_e	N.A.	3,82	3,38	-0,05	-18,30
LT - Lithuania	€ / MWh_e	N.A.	10,83	0,64	-4,73	-35,40
LV - Latvia	€ / MWh_e	N.A.	-1,00	-0,09	-0,09	-0,06
SI - Slovenia	€ / MWh_e	16,63	11,26	1,07	1,07	5,04
SK - Slovakia	€ / MWh_e	0,00	0,00	0,00	0,00	0,00

Table 53: Levelized CO_2 costs of electricity in the second ETS period (Scenario A)

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	-0,45	-1,08	0,39	0,39	5,86
EE - Estonia	€ / MWh_e	N.A.	0,00	0,00	0,00	0,00
FI - Finland	€ / MWh_e	N.A.	22,68	8,80	6,89	-7,93
IT - Italy	€ / MWh_e	N.A.	5,36	4,60	-0,07	-24,96
LT - Lithuania	€ / MWh_e	N.A.	15,21	0,87	-6,43	-48,15
LV - Latvia	€ / MWh_e	N.A.	-1,41	-0,12	-0,12	-0,08
SI - Slovenia	€ / MWh_e	23,34	15,80	1,46	1,46	6,86
SK - Slovakia	€ / MWh_e	0,00	0,00	0,00	0,00	0,00

Table 54: Levelized CO_2 costs of electricity in the second ETS period (Scenario B)

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	-0,52	-1,24	0,43	0,43	6,49
EE - Estonia	€ / MWh_e	N.A.	0,00	0,00	0,00	0,00
FI - Finland	€ / MWh_e	N.A.	25,89	9,73	7,61	-8,76
IT - Italy	€ / MWh_e	N.A.	6,11	5,08	-0,08	-27,55
LT - Lithuania	€ / MWh_e	N.A.	17,42	0,96	-7,12	-53,33
LV - Latvia	€ / MWh_e	N.A.	-1,61	-0,13	-0,13	-0,09
SI - Slovenia	€ / MWh_e	26,70	18,07	1,62	1,62	7,59
SK - Slovakia	€ / MWh_e	0,00	0,00	0,00	0,00	0,00

Table 55: Levelized CO_2 costs of electricity in the second ETS period (Scenario C)

Variances among countries are huge and demonstrate that very different investment conditions were effective for new power plants built within the 2nd ETS period. It shall be emphasised however, that these calculations assume, that the allocation rules of the 2nd ETS period are applied over the whole lifetime of the power plants. This was for sure not the expectation of an investor that is installing a power plant within the time frame 2008 to 2012. Therefore the calculations are only hypothetical. For new power plant projects as investigated in this study the allocation rules of the 2nd ETS period are irrelevant. In general, investment conditions may have even improved from the second to the third ETS period alone by the fact, that insecurities about the future development of the ETS periods as well as distortions of competition have significantly been reduced with the 3rd ETS period.

But nevertheless does a comparison with CO_2 costs accruing in the 3rd ETS period demonstrate the additional burden that the investor has to take into account due to full auctioning. This is calculated as the difference between the CO_2 costs in the 3rd and 2nd ETS period, expressed in €/MWh_e in Table 56, Table 57 and Table 58.

Although in the 3rd ETS period the gas turbines lose their large advantages from the 2nd ETS period, they are in average still better off than lignite power plants, due to the large specific CO_2 emissions from lignite combustion. The least worsening of investment conditions due to the changes from 2nd to 3rd ETS period will be for CCGT plants, particularly if the CCGTs will run in base load. From this point of view, the change from the 2nd to the 3rd trading phase does promote CCGT by providing them a better competitive standing in the market.

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	26.53	21.79	8.45	8.45	8.41
EE - Estonia	€ / MWh_e	N.A	20.56	8.61	8.61	12.53
FI - Finland	€ / MWh_e	N.A	4.22	2.10	3.51	18.28
IT - Italy	€ / MWh_e	N.A	16.40	5.14	8.57	30.70
LT - Lithuania	€ / MWh_e	N.A	9.99	8.05	13.41	48.04
LV - Latvia	€ / MWh_e	N.A	21.82	8.77	8.77	12.70
SI - Slovenia	€ / MWh_e	9.06	9.34	7.55	7.55	7.51
SK - Slovakia	€ / MWh_e	25.75	20.65	8.64	8.64	12.57

Table 56: CO_2 costs on electricity: difference of 3rd compared to 2nd ETS period (Scenario A)

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	37.28	30.62	11.49	11.49	11.43
EE - Estonia	€ / MWh_e	N.A	28.85	11.73	11.73	17.07
FI - Finland	€ / MWh_e	N.A	5.92	2.87	4.78	24.91
IT - Italy	€ / MWh_e	N.A	23.00	7.01	11.69	41.86
LT - Lithuania	€ / MWh_e	N.A	14.04	10.95	18.24	65.35
LV - Latvia	€ / MWh_e	N.A	30.65	11.93	11.93	17.28
SI - Slovenia	€ / MWh_e	12.72	13.12	10.28	10.28	10.23
SK - Slovakia	€ / MWh_e	36.14	28.99	11.76	11.76	17.11

Table 57: CO_2 costs on electricity: difference of 3rd compared to 2nd ETS period (Scenario B)

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	42.78	35.14	12.74	12.74	12.68
EE - Estonia	€ / MWh_e	N.A	32.98	12.97	12.97	18.87
FI - Finland	€ / MWh_e	N.A	6.75	3.17	5.28	27.52
IT - Italy	€ / MWh_e	N.A	26.23	7.74	12.90	46.21
LT - Lithuania	€ / MWh_e	N.A	16.08	12.12	20.21	72.37
LV - Latvia	€ / MWh_e	N.A	35.11	13.22	13.22	19.14
SI - Slovenia	€ / MWh_e	14.55	15.00	11.37	11.37	11.32
SK - Slovakia	€ / MWh_e	41.35	33.16	13.01	13.01	18.93

Table 58: CO_2 costs on electricity: difference of 3rd compared to 2nd ETS period (Scenario C)

It shall be taken into account, however, that we look at power plants that deliver for different price bands in the market, i.e. that are designed to operate as peak load, intermediate load or base load power plant. Effectively this means, that for peak load power plants higher electricity generation costs are acceptable than for base load plants. Thus we express the additional CO_2 costs that accrue due to full auctioning in the 3rd phase (cf. Table 56 until Table 58) as%age of the composite costs of electricity that accrue at installation in the 2nd trading phase. These%age changes of electricity costs are listed for the three scenarios in Table 59, Table 60 and Table 61.

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	%	60%	38%	12%	11%	6%
EE - Estonia	%	N.A.	35%	13%	11%	9%
FI - Finland	%	N.A.	6%	3%	5%	15%
IT - Italy	%	N.A.	25%	6%	9%	21%
LT - Lithuania	%	N.A.	14%	10%	17%	42%
LV - Latvia	%	N.A.	38%	11%	10%	9%
SI - Slovenia	%	14%	13%	8%	7%	4%
SK - Slovakia	%	56%	35%	9%	9%	7%

Table 59: Electricity cost increase due to change from 2nd to 3rd ETS period (Scenario A)

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	%	86%	55%	17%	16%	8%
EE - Estonia	%	N.A.	50%	18%	16%	13%
FI - Finland	%	N.A.	7%	4%	7%	21%
IT - Italy	%	N.A.	35%	8%	13%	30%
LT - Lithuania	%	N.A.	19%	14%	24%	67%
LV - Latvia	%	N.A.	55%	16%	15%	12%
SI - Slovenia	%	18%	18%	11%	10%	6%
SK - Slovakia	%	80%	50%	13%	12%	10%

Table 60: Electricity cost increase due to change from 2nd to 3rd ETS period (Scenario B)

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	%	103%	69%	20%	19%	10%
EE - Estonia	%	N.A.	61%	21%	19%	15%
FI - Finland	%	N.A.	8%	5%	7%	24%
IT - Italy	%	N.A.	42%	9%	15%	36%
LT - Lithuania	%	N.A.	23%	17%	29%	84%
LV - Latvia	%	N.A.	68%	19%	17%	14%
SI - Slovenia	%	21%	21%	13%	12%	7%
SK - Slovakia	%	95%	62%	15%	14%	12%
Average	%	73%	44%	15%	16%	25%

Table 61: Electricity cost increase due to change from 2nd to 3rd ETS period (Scenario C)

These figures demonstrate that the relatively highest effect due to the change to full auctioning is not surprisingly found with lignite power plants.

This is particularly the case in Bulgaria and Slovakia, where electricity from new lignite power plants becomes about 60% more expensive (+60% in BG and +56% in SK) in Scenario A and about 100% more expensive (+103% in BG and +95% in SK) in Scenario C. The competitiveness of hard coal power plants is also worsened, but composite costs increase generally not as much as those of lignite power plants. Again from this view it becomes visible that CCGTs come off best. The relatively high additional burden for gas turbines can be attributed to their very protective treatment (i.e. over-allocation) in the NAPs of the 2nd ETS period.

Generally, in countries with strict allocation rules in the 2nd ETS period the change to full auctioning imposes only low additional costs. This is particularly the case for Finland where electricity costs of new power plants increase only by (depending on the scenario) 6% to 8% for hard coal power plants and by 3% to 7% for CCGTs due to the shift to full auctioning.

5.3 Levelized Costs of Electricity with Full Auctioning

The levelized costs of electricity in the 3rd ETS period for new power plants in all analysed EU countries are shown in Table 62, Table 63 and Table 64 for Scenarios A, B and C. Under the given scenario assumptions lignite power plants are generally (i.e. in average over all analysed countries) the most competitive power plants for base load, at least in Scenario A (reference) and Scenario B (fragmented action). And this despite the CO_2 costs of full auctioning integrated in these electricity costs.

It shall be emphasised, that Scenario C is the one with the highest CO_2 costs but lowest fuel costs (cf. section 5.1 and Annex I and Annex II). This would shift the competitive advantage for base load power plants towards CCGT plants. The reason is that CCGT plants do not only have lower CO_2 emissions but also relatively high fuel cost components compared to coal power plants (cf. Figure 85, Figure 86 and Figure 87). That's why CCGT plants are generally better off in a world with global climate action (Scenario C) than with fragmented action (Scenario B), even though in both scenarios the 80% CO_2 reduction goal in 2050 is achieved.

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	70.98	79.12	76.85	83.15	146.99
EE - Estonia	€ / MWh_e	N.A.	80.04	77.31	83.93	149.59
ES - Spain	€ / MWh_e	N.A.	86.51	78.41	85.67	158.72
FI - Finland	€ / MWh_e	N.A.	79.48	69.24	76.39	143.04
GR - Greece	€ / MWh_e	72.98	81.02	88.03	94.94	170.67
HU - Hungary	€ / MWh_e	71.83	79.89	89.62	96.20	167.99
IT - Italy	€ / MWh_e	N.A.	82.14	93.63	100.77	179.35
LT - Lithuania	€ / MWh_e	N.A.	79.53	86.76	93.21	162.36
LV - Latvia	€ / MWh_e	N.A.	79.53	86.30	92.73	161.64
PL - Poland	€ / MWh_e	71.88	74.86	72.61	79.18	142.93
RO - Romania	€ / MWh_e	71.37	79.46	76.86	83.29	147.84
SI - Slovenia	€ / MWh_e	72.44	80.45	102.84	109.58	189.04
SK - Slovakia	€ / MWh_e	71.93	79.96	102.56	109.15	186.70

Table 62: Levelized composite costs of electricity (Scenario A)

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	80.75	85.91	77.70	83.99	148.23
EE - Estonia	€ / MWh_e	N.A.	86.68	78.20	84.82	150.89
ES - Spain	€ / MWh_e	N.A.	92.79	79.34	86.60	160.07
FI - Finland	€ / MWh_e	N.A.	86.18	70.48	77.63	144.85
GR - Greece	€ / MWh_e	82.53	87.67	88.53	95.43	171.38
HU - Hungary	€ / MWh_e	81.40	86.56	90.03	96.60	168.58
IT - Italy	€ / MWh_e	N.A.	88.65	93.97	101.11	179.85
LT - Lithuania	€ / MWh_e	N.A.	86.26	87.25	93.69	163.07
LV - Latvia	€ / MWh_e	N.A.	86.25	86.80	93.24	162.38
PL - Poland	€ / MWh_e	81.45	81.78	73.67	80.25	144.48
RO - Romania	€ / MWh_e	81.01	86.17	77.74	84.17	149.11
SI - Slovenia	€ / MWh_e	81.99	87.11	102.75	109.49	188.91
SK - Slovakia	€ / MWh_e	81.50	86.63	102.47	109.06	186.56

Table 63: Levelized composite costs of electricity (Scenario B)

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	84.14	86.15	75.28	81.57	144.70
EE - Estonia	€ / MWh_e	N.A.	86.76	75.86	82.48	147.47
ES - Spain	€ / MWh_e	N.A.	92.18	77.06	84.32	156.76
FI - Finland	€ / MWh_e	N.A.	86.50	68.70	75.85	142.27
GR - Greece	€ / MWh_e	85.70	87.77	85.53	92.44	167.03
HU - Hungary	€ / MWh_e	84.60	86.67	86.90	93.47	164.02
IT - Italy	€ / MWh_e	N.A.	88.57	90.74	97.88	175.15
LT - Lithuania	€ / MWh_e	N.A.	86.43	84.25	90.69	158.70
LV - Latvia	€ / MWh_e	N.A.	86.43	83.83	90.27	158.05
PL - Poland	€ / MWh_e	84.64	82.51	71.60	78.17	141.46
RO - Romania	€ / MWh_e	84.28	86.33	75.36	81.79	145.66
SI - Slovenia	€ / MWh_e	85.16	87.21	98.83	105.56	183.19
SK - Slovakia	€ / MWh_e	84.69	86.75	98.53	105.12	180.83

Table 64: Levelized composite costs of electricity (Scenario C)

However, in some countries can CCGT power plants compete already in Scenario A (with lowest ETS prices) with coal power plants, even in base load. This holds for the countries Estonia, Spain and Finland, where no cheap lignite PP alternatives are available. In Scenario B and particularly in Scenario C with highest ETS prices the competitiveness of CCGT in base load improves furthermore. Only Hungary, Italy, Slovenia and Slovakia would still like to opt for new coal power plants in Scenario C for supplying base load.

Furthermore, hard coal power plants can generally not compete with lignite power plants, with the only exemption of Poland in Scenario C (in which case however the CCGT base load power plant would be the most favourable base load option anyway). Thus, contingent on the local availability of lignite, new lignite-fuelled power plants are generally spoken the most competitive technology of choice for base load power plants.

Hard coal power plants remain only an option in countries, where no lignite is available. And even then a hard coal power plant is the most competitive base load option only in Italy, Lithuania and Latvia in the scenarios A and B (in Italy also in Scenario C).

A large part of the composite levelized costs are marginal costs, i.e. variable OPEX. Marginal costs are mainly containing fuel costs and CO_2 costs, depending on the type of power plant. An example of the cost breakdown for all three analysed base load power plants is shown for Hungary with Figure 85, Figure 86 and Figure 87. All three examples relate to Scenario C.

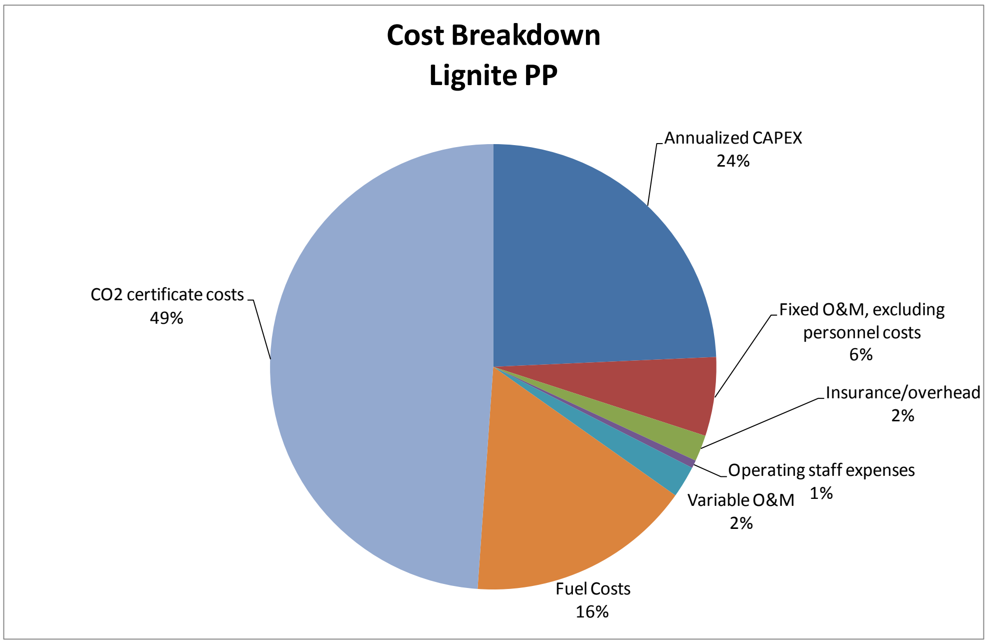


Figure 85: Cost breakdown of electricity generation costs for lignite power plant in Hungary (Scenario C)

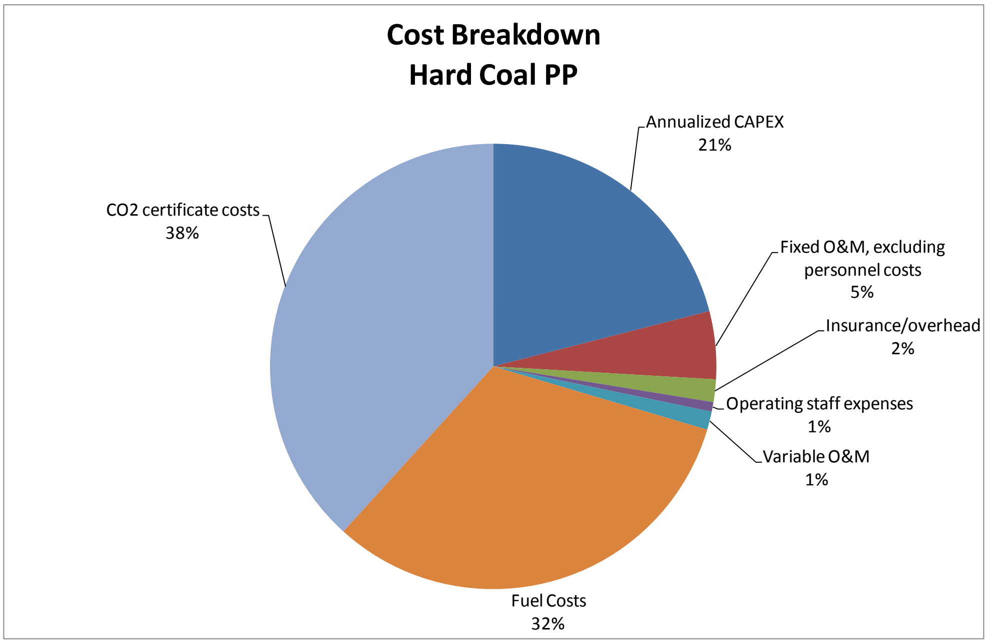


Figure 86: Cost breakdown of electricity generation costs for hard coal power plant in Hungary (Scenario C)

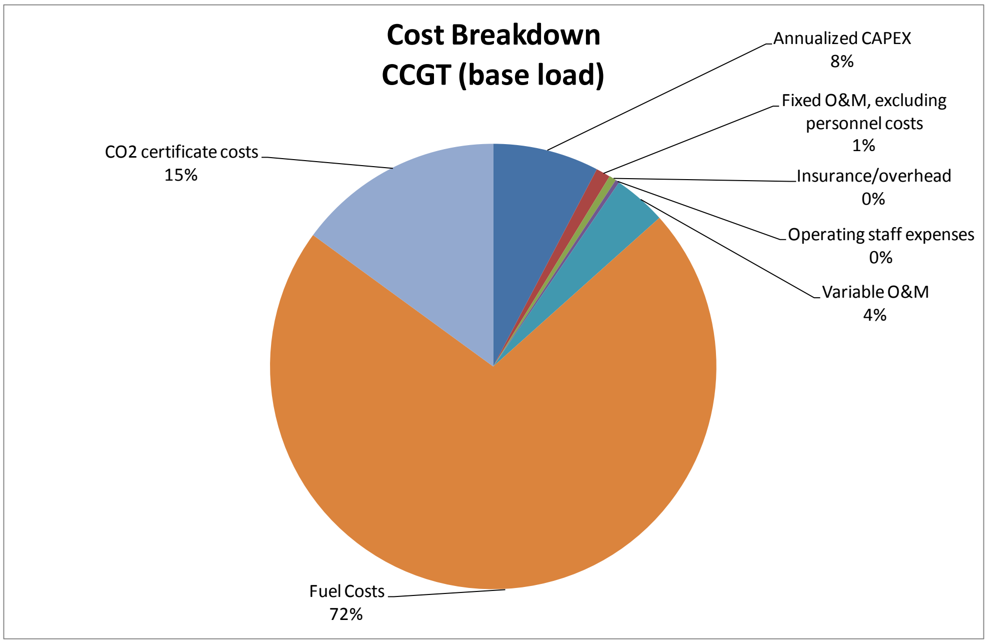


Figure 87: Cost breakdown of electricity generation costs for CCGT (base load) in Hungary (Scenario C)

Although composite costs in Hungary in Scenario C are at almost the same absolute level for the three base load power plants (cf. Table 64), the relative composition of those costs is quite different among the plants. Almost half of the electricity generation costs for the lignite power plant are caused by CO_2 certificates. For the hard coal power plant fuel costs and CO_2 costs are both about equally dominating total costs, whereas the costs of the CCGT are dominated by fuel costs.

The explicit calculation of the levelized costs and their composition that is underlying Figure 85, Figure 86 and Figure 87 is shown exemplarily in Table 65. On the basis on the annual energy and emission balance of each power plant the CAPEX and its components as well as the OPEX in the starting year and its components are compiled. All figures are brought on present values by assuming certain annual escalation rates for OPEX components. By relating the cost items in present values to the generated electricity in present value leads to levelized cost items, either by summing up total costs (composite costs) or only variable OPEX (marginal costs).

Item	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
Annual electricity production	Gwh_e/a	7,879	5,556	5,910	3,546	186
Annual fuel consumption	Gwh_t/a	18,238	12,184	10,687	6,412	488
Specific fuel costs (levelized, real)	€ / MWh_t	6.0	12.7	34.4	35.0	38.8
Annual CO_2 emissions	t/a	7,368,090	4,167,000	2,158,807	1,295,284	98,674
Specific CO_2 certificate costs (levelized, real)	€ / t CO_2	44.22	44.22	35.62	35.62	35.62
CAPEX	**mln €**	**2,650**	**1,656**	**557**	**557**	**77**
EPC price (procurement cost, without construction)	mln €	2,173	1,376	480	480	68
Construction works	mln €	40	32	11	11	2
Owner's costs (referred to EPC)	mln €	221	141	49	49	7
Interest during construction	mln €	216	107	17	17	1
OPEX starting year	**mln € / a**	**494.5**	**374.1**	**470.7**	**289.4**	**24.5**
Fixed O&M, excluding personnel costs	mln € / a	33.2	20.6	4.8	4.8	0.3
Insurance(of equipment)/overhead	mln € / a	11.06	6.88	2.40	2.40	0.34
Operating staff	mln € / a	2.2	1.9	1.0	1.0	0.5
Variable O&M	mln € / a	13.39	5.56	17.73	10.64	0.84
Fuel Costs (levelized, real)	mln € / a	108.9	154.9	367.9	224.5	18.9
CO_2 certificate costs (levelized, real)	mln € / a	325.8	184.3	76.9	46.1	3.5
Present Values of Costs	**mln €**	**10,907**	**7,880**	**7,234**	**4,669**	**429**
CAPEX	mln €	2,650	1,656	557	557	77
Fixed O&M, excluding personnel costs 1.0%	mln €	622	387	75	75	5
Insurance(of equipment)/overhead 1.0%	mln €	207	129	38	38	5
Operating staff 3.8%	mln €	62	55	21	21	12
Variable O&M 1.0%	mln €	251	104	278	167	13
Fuel Costs	mln €	1,782	2,534	5,183	3,162	267
CO_2 certificate costs	mln €	5,331	3,015	1,083	650	50
PV electricity production	TWh	128.9	90.92	83.25	49.95	2.61
Levelized composite cost	**€ / MWh_e**	**84.6**	**86.7**	**86.9**	**93.5**	**164.0**
Levelized marginal cost	**€ / MWh_e**	**57.1**	**62.2**	**78.6**	**79.6**	**125.9**

Table 65: Calculation of levelized costs in the model: The example of Hungary for Scenario C

Remarkable is the generally rather high share of marginal costs that is obtained among all scenarios. According to Table 66, Table 67 and Table 68 marginal cost make out even for lignite power plants always at least 60% or more, due to the high share of CO_2 costs. With such high marginal cost parts, coal power plants come closer to the economic characteristics that are obviously observed for peak load power plants.

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	63%	71%	90%	84%	76%
EE - Estonia	€ / MWh_e	N.A.	69%	89%	83%	75%
ES - Spain	€ / MWh_e	N.A.	68%	88%	82%	71%
FI - Finland	€ / MWh_e	N.A.	66%	87%	80%	69%
GR - Greece	€ / MWh_e	61%	68%	90%	85%	74%
HU - Hungary	€ / MWh_e	62%	69%	91%	86%	77%
IT - Italy	€ / MWh_e	N.A.	67%	90%	85%	75%
LT - Lithuania	€ / MWh_e	N.A.	70%	91%	86%	78%
LV - Latvia	€ / MWh_e	N.A.	70%	91%	85%	78%
PL - Poland	€ / MWh_e	62%	67%	89%	83%	74%
RO - Romania	€ / MWh_e	62%	70%	89%	84%	76%
SI - Slovenia	€ / MWh_e	61%	69%	92%	87%	79%
SK - Slovakia	€ / MWh_e	62%	69%	92%	87%	80%

Table 66: Marginal costs as%age of composite costs (Scenario A)

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	68%	73%	90%	84%	76%
EE - Estonia	€ / MWh_e	N.A.	71%	89%	84%	75%
ES - Spain	€ / MWh_e	N.A.	71%	88%	82%	71%
FI - Finland	€ / MWh_e	N.A.	69%	87%	80%	70%
GR - Greece	€ / MWh_e	65%	71%	90%	85%	74%
HU - Hungary	€ / MWh_e	66%	72%	91%	86%	77%
IT - Italy	€ / MWh_e	N.A.	70%	90%	85%	75%
LT - Lithuania	€ / MWh_e	N.A.	72%	91%	86%	78%
LV - Latvia	€ / MWh_e	N.A.	72%	91%	86%	78%
PL - Poland	€ / MWh_e	66%	70%	89%	83%	74%
RO - Romania	€ / MWh_e	67%	72%	90%	84%	76%
SI - Slovenia	€ / MWh_e	66%	71%	92%	87%	79%
SK - Slovakia	€ / MWh_e	66%	72%	92%	87%	80%

Table 67: Marginal costs as%age of composite costs (Scenario B)

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	69%	73%	90%	84%	76%
EE - Estonia	€ / MWh_e	N.A.	71%	89%	83%	74%
ES - Spain	€ / MWh_e	N.A.	70%	88%	82%	70%
FI - Finland	€ / MWh_e	N.A.	69%	87%	80%	69%
GR - Greece	€ / MWh_e	67%	71%	90%	84%	74%
HU - Hungary	€ / MWh_e	68%	72%	90%	85%	77%
IT - Italy	€ / MWh_e	N.A.	70%	90%	84%	74%
LT - Lithuania	€ / MWh_e	N.A.	72%	90%	85%	77%
LV - Latvia	€ / MWh_e	N.A.	72%	90%	85%	77%
PL - Poland	€ / MWh_e	67%	70%	88%	82%	73%
RO - Romania	€ / MWh_e	68%	72%	89%	84%	75%
SI - Slovenia	€ / MWh_e	67%	71%	91%	87%	78%
SK - Slovakia	€ / MWh_e	67%	72%	92%	87%	79%

Table 68: Marginal costs as%age of composite costs (Scenario C)

Figure 88, Figure 89 and Figure 90 illustrate the components of electricity costs for all three scenarios. From Scenario A to Scenario C increasingly higher CO_2 cost components are more or less offset by fuel cost components that are generally decreasing from Scenario A to Scenario C. Figures of CO_2 cost components and fuel cost components of levelized electricity costs are also given in Annex III and Annex IV, respectively.

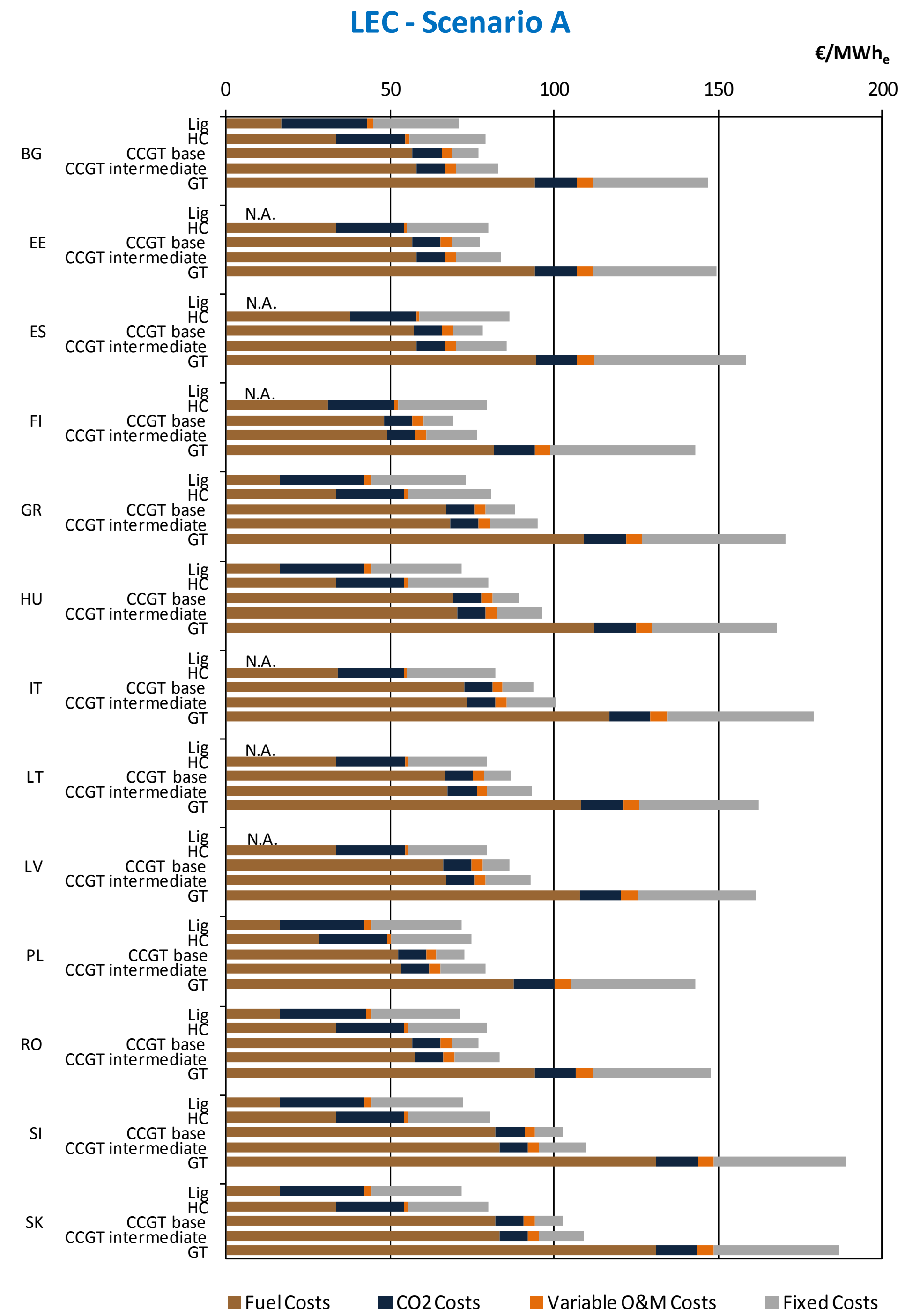


Figure 88: Composition of levelized electricity costs in Scenario A

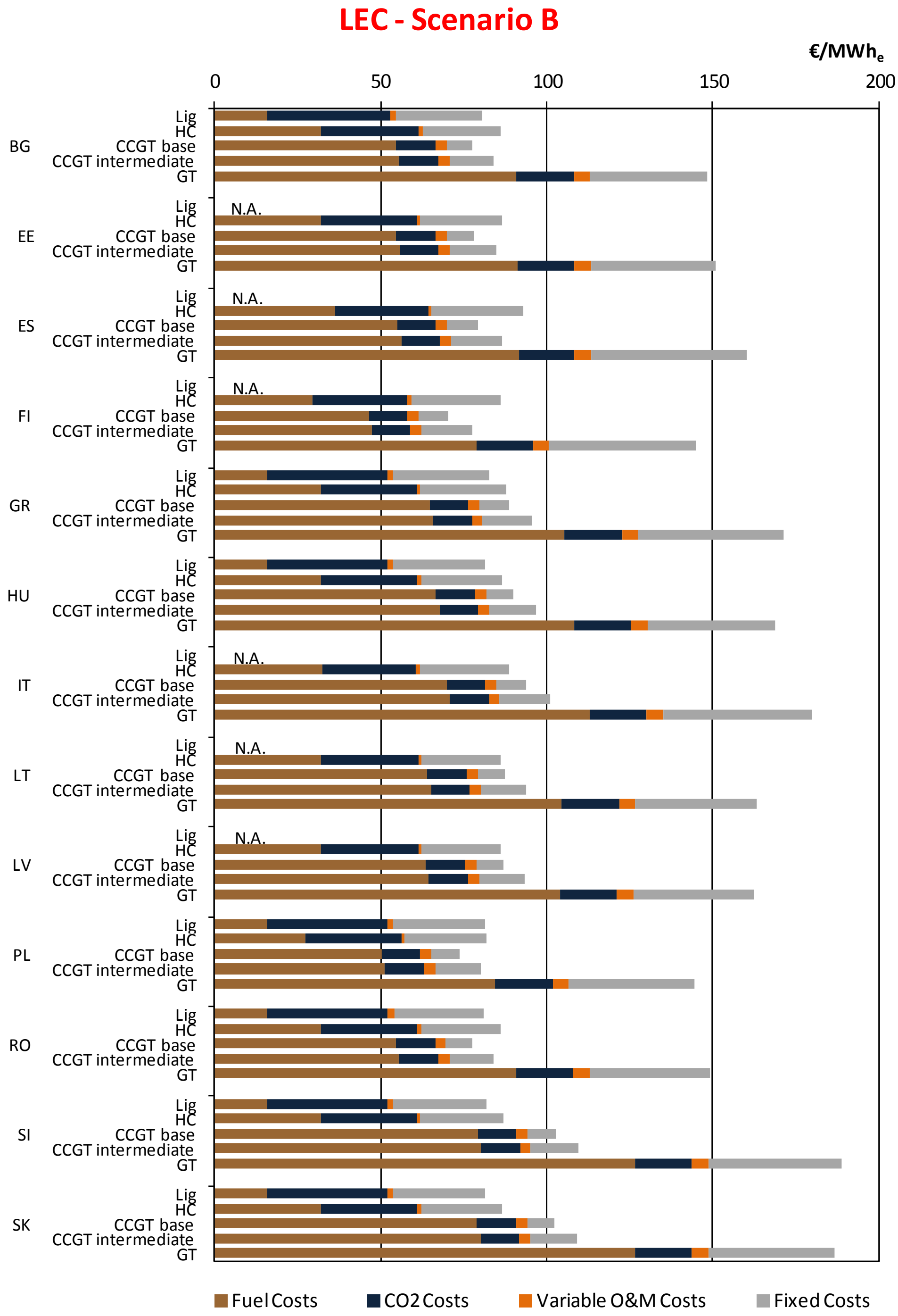


Figure 89: Composition of levelized electricity costs in Scenario B

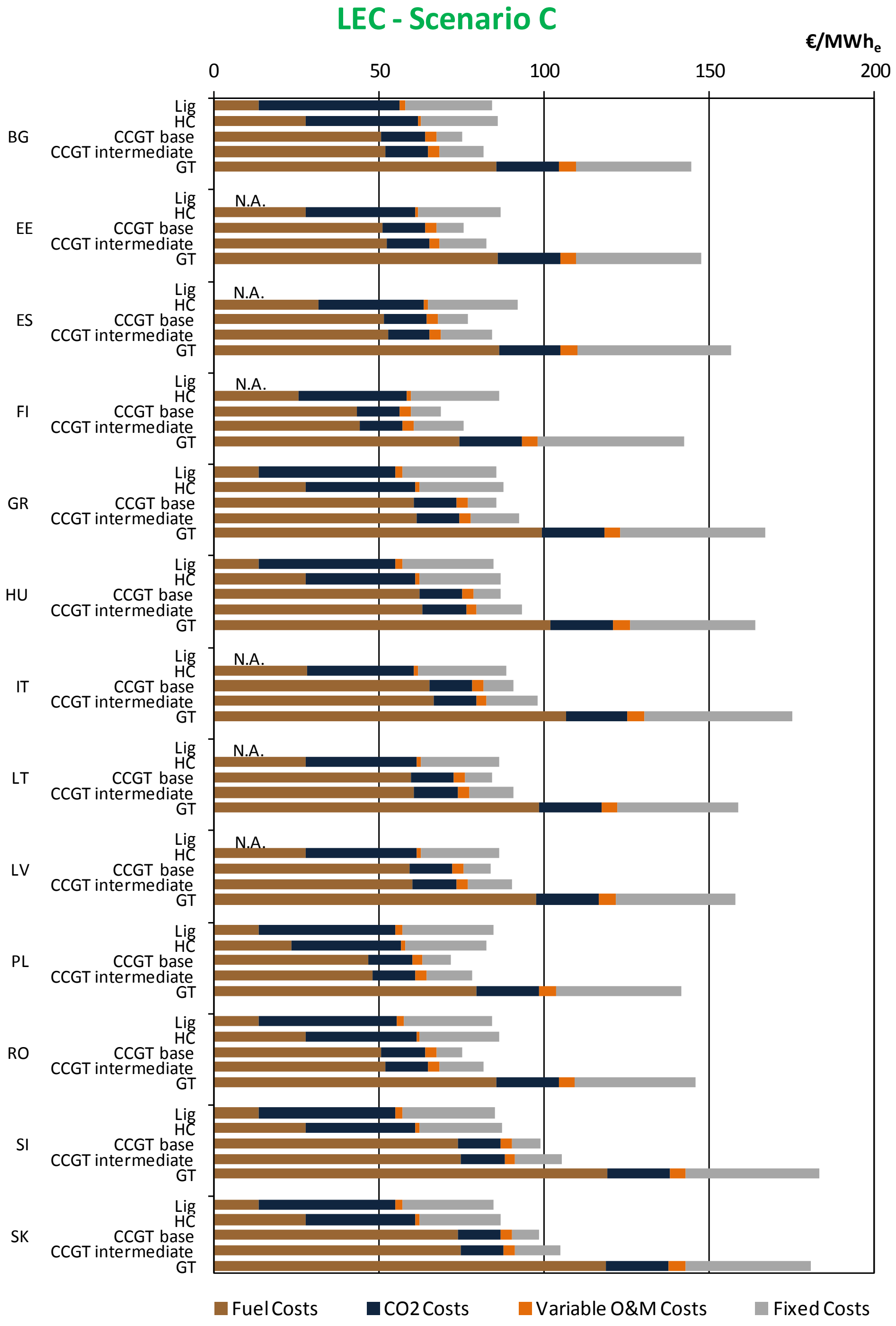


Figure 90: Composition of levelized electricity costs in Scenario C

5.4 Conclusions

Based on the LEC calculation of the model, the microeconomic effects from the change to full auctioning from 2nd to 3rd ETS period are analysed. The investigation of NAPs of some EU countries shows that for new power plants investment conditions in the 2nd ETS period regarding emission trading greatly vary among the type of power plants, but also among the EU countries. Particularly gas turbines were effectively over-allocated with emission rights. Whereas in some countries (particularly in Finland) a deficit of more than 50% of the required certificates remains after allocation, especially for coal power plants in Slovenia, Lithuania and Finland. Levelized CO_2 costs of electricity in the second ETS period range in average around 5 to 9 €/MWh_e for new coal power plants and around 0 to 2 €/MWh_e for new CCGTs. New peak load gas turbines could in some countries greatly benefit from over-allocation with an equivalent value of up to 53 €/MWh_e in Scenario C. CO_2 costs are of course highest in Scenario C and lowest in Scenario A. From Scenario A to Scenario C the difference makes up for about another 50% higher CO_2 costs for natural gas fired power plants and for about another 60% higher CO_2 costs for coal fired power plants.

It shall be emphasised however, that the CO_2 cost calculations assume, that the allocation rules of the 2nd ETS period are applied over the whole lifetime of the power plants. This was for sure not the expectation of an investor that is installing a power plant within the time frame 2008 to 2012. Therefore the calculations are only hypothetical. For new power plant projects as investigated in this study the allocation rules of the 2nd ETS period are irrelevant. In general, investment conditions may have even improved from the second to the third ETS period alone by the fact, that insecurities about the future development of the ETS periods as well as distortions of competition have significantly been reduced with the 3rd ETS period.

But nevertheless does a comparison with CO_2 costs accruing in the 3rd ETS period demonstrate the additional burden that the investor has to take into account due to full auctioning. The change from the 2nd to the 3rd phase of ETS does the least harm to CCGT's plants, which are not like GTs loosing allocation privileges, but which are also not like coal power plants hit by high specific CO_2 emissions. Particularly if CCGTs will run in base load, the change to the 3rd ETS period causes them in average over all investigated countries only between about 7 to 11 €/MWh_e additional costs, depending on the regarded scenario.

For the other power plant types CO_2 additional costs caused by the change from NAP allocation to full auctioning range roughly between about 15 to 30 €/MWh_e as average over all countries. But for single countries in Scenario C it can reach up to 72 €/MWh_e for gas turbines in Lithuania or up to 43 €/MWh_e for lignite power plants in Bulgaria. The last-mentioned cases would mean about a doubling of the total electricity costs.

In the third ETS period full auctioning is the general principle applied for new power plants. Nevertheless are the most CO_2 emitting lignite fired power plants still the most competitive base load power plant option, at least in Scenario A and for some countries also in scenarios B and even in C. However, in the global action decarbonisation Scenario C do the highest CO_2 prices combined with the lowest fuel prices shift the competitive advantage for base load power plants generally towards natural gas fired CCGT plants.
Another outcome from the LEC comparison: Hard coal power plants can generally not compete with lignite power plants and are thus only in such countries an option for base load, where no lignite is available and where electricity generation from CCGT power plants is expensive. This is the case for Italy and in scenarios A and B also for Lithuania and Latvia.

Remarkable is the generally rather high share of marginal costs among total composite electricity costs in all three scenarios. Marginal cost make out even for lignite power plants always at least 60% or more, due to the high share of CO_2 costs. With such high marginal cost shares, coal power plants come closer to the economic characteristics that are obviously observed for peak load power plants. In the example of Hungary in Scenario C, about half the electricity costs of the lignite power plant are caused by CO_2 costs. For the hard coal power plant, fuel costs and CO_2 costs are both about equally dominating total costs, whereas the costs of the CCGT base load plant are dominated by fuel costs.

6. Non-EU Power Plant Investment Options in Competition to the EU

In this chapter, investigations are undertaken of investment options in new power plants outside the EU that are dedicated for electricity transmission into the EU.

First, all unfeasible investment options are eliminated in section 6.1 with the decision tree. Then, specific conditions in the non-EU countries are discussed and quantified in section 6.2. This concerns, on the one hand, country-specific risks and, on the other, cross-border electricity transmission costs and their impact on the investment decision. In section 6.3, a general understanding is developed of the competitive advantage of investments outside the EU that are in competition with the non-EU country regarding the preferable site for a new power plant. Based on this understanding, the pair-wise competiveness of pairs of countries is assessed using the model in section 6.4. This leads to a list of the most promising investment conditions for electricity import into the EU.

6.1 Application of the Decision Tree

Using the decision tree, investment factors are addressed that are non-tangible or are not quantifiable with the decision-making model but would lead to an exclusion of investment options. Hence, in the following, all investment options are identified for which sufficient transmission capacity for electricity import into the EU (section 6.1.1), access to fuel (section 6.1.2), and acceptable political and regulatory investment conditions (section 6.1.3) are available.

6.1.1 Transmission options for electricity import into the EU

In the following, the transmission options for electricity import from non-EU countries into the EU are analysed. A lack of transmission opportunities may pose either an insurmountable barrier or at least a considerable risk for power plant investments that are scheduled for electricity export into the EU and would thus prohibit the investment. The analysis focuses on transmission options that could arise from using existing connections as well as on transmission options from new transmission lines to be built between EU and non-EU countries.

6.1.1.1 Existing transmission links

In this section, the existing grid is analyzed for electricity transmission opportunities from non-EU to EU countries. The existing power lines between EU and non-EU countries are listed and remaining free capacities are identified and verified.

Generally, it is noted that power systems like the ENTSO-E grid are highly meshed with a large number of power lines, so determining free capacities is a complex task. It would actually require simulation calculations for the whole regional network, but for the purpose of this report a simplified approach had to be taken by considering solely information on historical free capacities along the power line itself without regarding any network system feedback effects.

The current grid situation in Europe was analyzed based on the ENTSO-E-grid map and all existing grid connections between EU and non-EU countries at 220 kV and higher are listed in Table 69. Only these connections are of relevance for new power plant projects. Description of these power systems can be found in section 4.2.6.2.4.

Besides the physical and technical transfer capacity of a power line (total transfer capacity, TTC), the capacity is described by the net transfer capacity (NTC), which is fixed by subtracting a reserve capacity, termed the transmission reliability margin (TRM), for reasons of security of supply. Table 69 contains in one column the NTC values as (and if) published by national TSOs.

The rights to use the lines for energy interexchange within a defined capacity range are traded on a yearly, monthly and daily basis (already allocated capacity, AAC). The available transfer capacity (ATC) of each time-dependent capacity product remains for further usage and trading. To determine the overall remaining ATC, the ATC values of all time-specific capacity products as published on trading platforms are totalled. ATC and NTC values are published by most TSOs or trading platforms to varying qualities and differing intervals for the total of all lines connecting two countries. NTC values as published for the most recent months and years were used for this study. Seasonal variations were observed to be relatively insignificant and played no further rule with regard to the rough accuracy.

NTC = TTC - TRM
ATC = NTC - AAC

However, at several borders, the physical power flows differ from the scheduled market power flows in magnitude or even in direction due to uncontrolled loop flows. These transit power flows are unscheduled, violate the network security rules and make allocation of available transmission capacities for further investments more difficult. The growing use of renewable energies and the resulting impossibility of forecasting supply will significantly decrease the ATC in future.

Consequently, actually measured physical power flows as they happen are a better indicator for free capacities than ATC values. Physical load flows are also published by the TSOs. We subtracted these from the NTC values to obtain an estimate of free remaining capacities, as shown in column “free” in Table 69.

No	EU country / grid	non-EU country / grid	sync	network conditions	NTC [MW]	free [MW]	sufficient capacity for new power plants?
1a		Turkey / sync. to ENTSO-E RG CE	x	2 x 400 kV	n.a.	n.a.	new capacities due to envisaged synchronization
1b	Bulgaria / ENTSO-E RG CE	FYROM / ENTSO-E RG CE	x	1 x 400 kV	200-300	50-75	not enough free capacity
1c		Serbia / ENTSO-E RG CE	x	1 x 400 kV	250-300	70	not enough free capacity
2	Estonia / ENTSO-E RG Baltic	Russia / IPS/UPS	x	3 x 300 kV	1000	400	fluctuating values; peak load GT feasible
3	Finland / ENTSO-E RG Nordic	Russia / IPS/UPS		1 x BtB in Russia + 2 x 400 kV	1100	100-400	fluctuating values; peak load GT feasible
4a		Turkey / sync. to ENTSO-E RG CE	x	1 x 400 kV	n.a.	n.a.	new capacities due to envisaged synchronization
4b	Greece / ENTSO-E RG CE	Albania / sync. to ENTSO-E RG CE	x	1 x 400 kV	100-150		no free capacity
4c		FYROM / ENTSO-E RG CE	x	2 x 400 kV	300	0-50	not enough free capacity
5a		Ukraine (Burshtyn island) / sync. to ENTSO-E RG CE	x	1 x 400 kV + 1 x 220 kV	(800)	n.a.[7]	no existing, reliable data
5b	Hungary / ENTSO-E RG CE	Croatia / ENTSO-E RG CE	x	2 x 400 kV (double circuit)	800	100	not enough free capacity
5c		Serbia / ENTSO-E RG CE	x	1 x 400 kV	600	200	peak load GT feasible
6	Latvia / ENTSO-E RG Baltic	Russia / IPS/UPS	x	1 x 300 kV	400	0	no free capacity
7a	Lithuania /	Belarus / IPS/UPS	x	1 x 750 kV + 4 x 300 kV	1100	400	fluctuating values; peak load GT feasible
7b	ENTSO-E RG Baltic	Russia (Kaliningrad) / IPS/UPS	x	2 x 300 kV	550-650	50-100	not enough free capacity
8	Poland / ENTSO-E RG CE	Ukraine (Burshtyn island) / sync. ENTSO-E RG CE	x	1 x 220 kV isolated mode	n.a.	n.a.[7]	no existing, reliable data
9a		Moldova (islanded mode) / sync. to ENTSO-E RG CE	x	1 x 400 kV isolated mode	160	0	no free capacity
9b	Romania / ENTSO-E RG CE	Ukraine (Burshtyn island) / sync. to ENTSO-E RG CE	x	1 x 400 kV	150	50-100	not enough free capacity
9c		Serbia / ENTSO-E RG CE	x	1 existing 380 kV	400	50	not enough free capacity
10	Slovak Republic / ENTSO-E RG CE	Ukraine (Burshtyn Island) / sync. to ENTSO-E RG CE	x	1 x 400 kV	n.a.	n.a.[7]	no existing, reliable data
11	Slovenia / ENTSO-E RG CE	Croatia / ENTSO-E RG CE	x	2 x 400 kV + 2 x 220 kV	1000	100	not enough free capacity
12	Spain / ENTSO-E RG CE	Morocco / Maghreb Pool	x	1 x 400 kV AC submarine-cable	600	0	not enough free capacity

Table 69: Existing transmission lines between analysed EU and non-EU countries

Large investments in fossil power plants require long-term reservation of transmission capacities. For this reason, the annually traded transmission licenses have been analyzed too. If the demand for these long term capacities is higher than the offered amounts and only daily capacities are

[7] Free capacities are probably technically limited due to operation in the isolated network of Burshtyn Island.

available, it is assumed that, for a power plant investment, it will not be possible to rely on the availability of existing transmission capacities and thus the investment will not be feasible.

From Table 69, it becomes evident that the major part of the existing power lines is already used close to its maximum capacity. The assessed free capacities are rough estimates and derived from data of variable quality. Only mean values over time are assessed, but short-term fluctuations of free capacities can vary considerably and very often, as noted in the Table. For several links, especially for connections to Burshtyn Island, there are no reliable data available.

Burshtyn Island was isolated in 2003 from the rest of Ukraine's transmission network by de-energizing all lines between linking them. The small island grid is in synchronous operation with the ENTSO-E RG CE, so energy export into the EU is possible. The capacity of the existing lines is both limited and already in full use. Apart from the existing lines to Burshtyn Island, no further synchronized connections to ENTSO-E RG CE are planned And according to our estimate there will be no grid reinforcement projects to be completed up to 2020. The reason is that both options – the island remaining in the ENTSO-E grid and reintegration into Ukraine's transmission grid – are under discussion, so the uncertainty for any grid investments is critical.

All lines marked green in Table 69 display those transmission lines that are deemed to offer sufficient free transmission capacity for a new power plant. It is assumed that at least 200 MW of free capacity would be needed to provide adequate security for power transmission for a new GT with 150 MW.

Estonia is connected to Russia through three 300 kV AC lines, and physical power flows through them fluctuate widely. The estimated maximum free capacity amounts to 400 MW. The same is noted for the connection between Lithuania and Belarus. In both cases, only peak load power plants are considered to be possible. Since the measured power flows can differ from the scheduled ones and this is expected to become more pronounced, power plant investments that have to rely on free electricity export capacities are considered to be risky.

Finland and Russia are connected via a 1300 MW conventional HVDC back-to-back station, located in Russia. The Finnish grid is connected to this station via two 400 kV AC lines. The ATC values of this connection likewise fluctuate greatly. The situation is comparable with the two cases mentioned and described above.

Besides these currently available transmission capacities, the grid connection between Turkey and Continental Europe (Greece and Bulgaria) offers additional capacities too. Up to now, the transmission lines have been de-energized or used only with strongly limited capacities. But since the Turkish grid is about to be integrated into the ENTSO-E system – currently phase 3 of the temporary trial operation mode is ongoing – the transmission capacity of the existing power-lines will be fully accessible. Table 70 lists the existing grid connections between Turkey and the two EU countries Greece and Bulgaria with their technical transfer capacity. The usable network transfer capacities are estimated as 1000–1100 MW. The limitation compared to the capacity values in the table result from bottlenecks in the Serbian, Bulgarian and Romanian national grids [MEDRING_UP2]. However, investments in large power plant projects for electricity export into the EU can be considered to become feasible.

Turkey	EU	Type	Capacity
Babaeski	Phillipi (Greece)	AC single circuit	1510 MW
Babaeski	Maritsa East (Bulgaria)	AC single circuit	1500 MW
Hamitabat	Maritsa East (Bulgaria)	AC single circuit	1000 MW

Table 70: Existing connections between Turkey and the EU

6.1.1.2 New transmission links

In addition to already existing transmission lines from non-EU to EU countries, in this section the prospects for new power links from non-EU to EU countries are investigated. New lines may either support existing links by increasing the transfer capacities or may create completely new connections.

From the description of the European power system and its structure (see section 4.2.6.2), some important facts about implementation of new transfer capacities have to be considered. First of all, for all the potential electricity import options from non-EU countries that are included in the IPS/UPS to EU countries from the ENTSO-E RG CE system, imports are only possible through HVDC back-to-back interconnections or point-to-point HVDC transmission links. This applies to the following electricity import options:

- Finland - Russia
- Poland - Belarus
- Poland- Ukraine
- Slovakia - Ukraine (outside Burshtyn Island)
- Hungary - Ukraine (outside Burshtyn Island)

Second, another important criterion for the decision on which transmission system to use, AC or DC, is the distance between the countries to be connected. For the distances considered for this study, all power lines on land between synchronous networks can be constructed using conventional and comparatively cheap AC technology. For subsea connections the length for AC cables is strictly limited to about 60 km. Such an HVAC connection is feasible, for instance, between Spain and Morocco due to the short length of subsea cable of only 26 km. For longer distances, HVAC subsea cables are not feasible, so subsea cable interconnections have employ the HVDC technology. These considerations apply to following power import options:

- Ukraine - Bulgaria
- Egypt - Greece
- Libya - Greece
- Libya - Italy
- Tunisia - Italy
- Turkey - Romania
- Algeria - Spain
- Tunisia - Spain

Multiple HVDC in-feeds into HVAC systems can pose particular challenges for grid balances but such issues can be overcome technically by using the recently developed voltage source converter (VSC) technology. Such considerations apply especially for Spain and Italy, where multiple power import options would be possible via HVDC submarine cables.

Identification of new transmission lines between EU and non-EU countries is based on ENTSO-E’s Ten-Year Network Development Plan issued in 2010 [TYNDP 2010] and released as an update in 2012 [TYNDP 2012]. This is a compilation of transmission projects with European significance that meet various requirements. Its intent is to provide an overview of ongoing and confirmed transmission projects, and to ensure certainty when planning further investments (power plants, etc). The TYNDP was mandated by EU Directive 2009/713/EC [2009/713/EC] to coordinate EU-wide network development. This underlines its official status.

As a prerequisite for new transmission line projects to be listed in the TYNDP, the equipment has to be on HV level and shall lead to an increase of the grid transfer capacity of at least 500 MW or secure an output of 1 GW/10,000 km² of generation. Data input for the TYNDP is supplied by the national TSOs when publishing their yearly National Development Plans and the Regional Development Plans published by the ENTSO-E regional groups. The feasible integration of planned projects into the existing network is for each project counterchecked by complex network calculations performed by the TSOs.

Further, third party projects that are not part of the National Development Plans may be included in the TYNDP upon application. The projects have to fulfil the general TYNDP criteria outlined above, but they must also already possess a transmission license to become part of the TYNDP. Because they lack transmission licenses, several projects aren’t included and are therefore investigated individually. Those projects, though, remain relevant since they could still be granted transmission licenses. Thus for this study the TYNDP was not the only source for identification of new transmission lines. Part of the investigation was to determine which further projects are likely to be completed by 2020 and could become further transmission options for new power plants’ electricity transfer into the EU.

As a result, Table 71 lists the relevant projects – whether listed in the TYNDP or not – that increase power imports into the EU from non-EU countries. Additional information on technology, timing and reference number is likewise provided. Projects marked green are those that are deemed to have a chance for realization within the next ten years and that could provide enough transmission opportunities for new power plant investments in non-EU countries dedicated for electricity export into the EU. All transmission link capacities of the projects marked in green in Table 71 are assessed to be sufficient for all analysed types of fossil power plants.

No	EU		non-EU		distance [km]	sync	project description	capacity [MW]	project status time horizon	TYNDP ref-no
	country / grid	sub-station	country / grid	sub-station						
1a	Italy / ENTSO-E RG CE	-	Tunisia / Maghreb Pool	Cap Bon / El Haouria	350 km	x	HVDC sea cable, 400 kV, bipolar	1000 (second stage)	permitting long term	29.73
1b		Villanova	Montenegro / ENTSO-E RG CE	Tivat	375 km (sea) 75 km (land)	x	HVDC sea cable, 500 kV, bipolar	1000	under construction 2015	28.70
1c		-	Algeria / Maghreb Pool	-	-		HVDC sea cable	500 - 1000	design & permitting long term	29.A97
1d		Candia	Croatia / ENTSO-E RG CE	Konisko	220 km (sea) 60 km (land)	x	HVDC sea cable, 400 kV	500-1000	under consideration long term	[HVDC_IT]
1e		-	Libya / Mashreq Pool	-	-		HVDC sea cable	n.a.	under study long term	[HVDC_IT]
1f		Brindisi / Foggia	Albania / sync. to ENTSO-E RG CE	Durres / Vlore	-	x	HVDC sea cable, 400 kV	2x 500 (two stages)	(authorized) laut Terna long term	[HVDC_IT]
2a	Lithuania / ENTSO-E RG Baltic	Klaipeda	Russia/Kaliningrad / IPS/UPS	Sovetsk	-	x	AC OHL, 330 kV	n.a.	planned	[BALTIC_NPP]
2b		Jurbakas	Russia/Kaliningrad / IPS/UPS	Sovetsk	-	x	AC OHL, 330 kV	n.a.	planned	[BALTIC_NPP]
3a	Poland / ENTSO-E RG CE	-	Russia/Kaliningrad / IPS/UPS	Mamonovo	-		HVDC Back-to-Back	n.a.	under consideration	[BALTIC_NPP]
3b		Rzeszów	Ukraine / IPS/UPS	Chmielnicka	-		HVDC Back-to-Back	2x 600	planned	In TYNDP 2010: 366
3c		Narev	Belarus / IPS/UPS	Ross	-		HVDC OHL	600 - 1000	-	[BALTIC_NPP]
4a	Romania / ENTSO-E RG CE	Constanta	Turkey / sync. to ENTSO-E RG CE	Aliberköy	320 km (sea) 80 km (land)	x	HVDC sea cable	1000	planned long term	[HVDC_TR]
4b		-	Serbia / ENTSO-E RG CE	-	120 - 170 km (est.)	x	AC OHL, 400 kV, double circuit	n.a.	design & permitting 2015/2019	50.238
4c		Suceava	Moldova (islanded) / sync. to ENTSO-E RG CE	Balti	115 km		AC OHL, 400 kV	n.a.	under consideration long term	[AC_MOL]

Table 71: Potential transmission projects

In total, there are four ENTSO-E projects considered to be relevant. Three of these connect the Italian grid with the surrounding countries via HVDC subsea cables. The Italy - Montenegro link is already under construction. Between Romania and Serbia, one 400 kV AC power line with double circuit configuration is currently under construction, to offer an additional physical capacity of 1500 MW.

Projects 2a, 2b, 3a plus another direct HVDC link between Kaliningrad and Germany are being developed in connection with the planned nuclear power plant in the Kaliningrad region [B_NPP]. Construction of the Baltic Nuclear Power Plant started in February 2012 and commercial operation of the two 1000 MW blocks is scheduled to start in 2018. These will replace existing gas-fired power plants. The residual still large energy surplus will be exported into surrounding countries, for which purpose the above power links are planned. It is expected that their capacity will be fully required for evacuation of the new NPP's electricity. No other new power plants dedicated for electricity exports into the EU will find sufficient free remaining capacities as required for an investment decision.

Italy with its very special geographic position offers a huge number of possible transmission connections to non-EU countries. Besides the three ENTSO-E projects, three third party projects are discussed. The 500 MW HVDC connection between Italy and Albania (1f) is, according to the Italian TSO TERNA, already authorized and therefore considered to be relevant. Connections 1d to Croatia and 1e to Libya are already being discussed but as yet no reliable forecast can be made as both projects are still under consideration or study.

Project 3b in Table 71 foresees a re-launch of a 750 kV transmission line between Rzeszów (Poland) and Chmielnicka (Ukraine, outside of Burshtyn Island), that is currently out of operation. This concerns connection of the asynchronous systems of Poland and Ukraine. The project is listed in the [TYNDP 2010]. A back-to-back converter station with a rating of 2x 600 MW in the area of the Rzeszów station is considered. The Polish TSO PSE analysed various options for interconnected operation. Although listed in ENTSO-E's first [TYNDP 2010] and although the Polish ENTSO-E member PSE is involved in this project,the project was sorted out in ENTSO-E's second [TYNDP 2012] and is no more listed among the future transmission projects. It is thus seen to have no prospects for realisation by 2020.

The HVDC connection between Belarus and Poland, Project 3d in Table 71, will either be developed by a private investor or by the Polish state owned TSO [PSEDP 2012, CICS]. Due to financing problems and political uncertainty, the project is currently on hold (cf. section 8). The plan is to build a new line over an existing route that is now outdated and no longer usable and to connect via a back-to-back link to the Belarus territory.

In addition to the already discussed transmission link between Serbia and Romania, an HVDC subsea cable connection between Turkey and Romania (4a) has been under discussion for several years and deemed to be feasible and realizable within the next ten years, so this project is considered in this report. But reinforcement of existing power lines connecting Romania and Moldavia is not considered relevant as Moldova is dependent on the grid connection to Ukraine and electricity imports from Ukraine. This avoids planning reliability for any potential grid link investments (4c).

All transmission projects that offer potential electricity import options into the EU for new power plants to be built outside the EU are included in Table 72. Also a CAPEX estimate of the projects is given in this table. It must be emphasized, though, that this can only be a best guess due to limited information on the projects. Actual CAPEX for the projects may deviate considerably from case to case.

For CAPEX estimation, the cost figures as assessed in section 4.2.6.2 are used. If no parameters on the planned interconnections are given (cf. Table 71), a bi-polar system with a voltage of ±500 kV and a transmission capacity of 1000 MW is assumed for HVDC links. For some projects, the full information needed for price estimates is not given, in which case assumptions are made, marked * in the column type/description. If the project data offers a range of capacity and distance values, the maximum numbers are chosen. For the planned AC OHL power line between Romania and Serbia, the stated project capacity is based on standard assumptions for similar projects.

connection	ENTSO-E Number	Type / description	CAPEX	Capacity
Italy - Albania	private investor	HVDC connection 2 x 500 MW 330 km sea cable	594 Mio€ cable 440 Mio€ converter	1,000 MW transmission capacity of HVDC system
Italy - Tunisia	TYNDP 2012 project 29.73	HVDC connection 1000 MW 350 km sea cable	630 Mio€ cable 440 Mio€ converter	1,000 MW transmission capacity of HVDC system
Italy - Montenegro	TYNDP 2012 project 28.70	HVDC connection 1000 MW 375 km sea cable 75 km land cable	675 Mio€ cable 440 Mio€ converter	1,000 MW transmission capacity of HVDC system
Italy - Algeria	TYNDP 2012 project 29.A97	HVDC connection 500-1000 MW 310 km DC cable	558 Mio€ cable 440 Mio€ converter	1,000 MW transmission capacity of HVDC system
Poland - Belarus	private investor or Polish TSO	B2B, based on renewed 120 km AC line 600-1000 MW	52 Mio€ cable 264-440 Mio€ converter	up to 1,000 MW transmission capacity (B2B)
Romania - Turkey	private investor	HVDC connection 1000 MW * 320 km sea cable, 80 km land cable	720 Mio€ cable 440 Mio€ converter	1,000 MW transmission capacity of HVDC system
Romania - Serbia	TYNDP 2012 project 50.238	AC double circuit OHL 400 kV 120 - 175 km *	65 Mio€ HVAC OHL	1,500 MW total transmission capacity of OHL (n-1)

Table 72: Relevant transmission projects and their estimated CAPEX

6.1.1.3 Remaining transmission options for electricity import into the EU

From the analysis of existing as well as potential new transmission lines into the EU, the following transmission options for electricity import into the EU from new fossil fired power plants outside the EU are identified (see Table 73). As it turns out, transmission options are scarce. Only thirteen options remain that could provide sufficient transmission capacity for new power plants in non-EU countries for exporting their entire electricity generation into the EU.

existing / new	EU		non-EU			sync./async.	type of connection	possible PP capacity [MW]	types of power plant
	country	grid	country	grid	Energy Community				
existing	Bulgaria	ENTSO-E RG CE	Turkey	sync. ENTSO-E RG CE	not yet	sync.	HVAC	n.a.	all
existing	Greece	ENTSO-E RG CE	Turkey	sync. ENTSO-E RG CE	not yet	sync.	HVAC	n.a.	all
existing	Estonia	ENTSO-E RG BALTIC	Russian Federation	IPS/UPS	no	sync.	HVAC	400	GT
existing	Finland	ENTSO-E RG NORDIC	Russian Federation	IPS/UPS	no	asnyc.	B2B	100-400	GT
existing	Hungary	ENTSO-E RG CE	Serbia	ENTSO-E RG CE	yes	sync.	HVAC	200	GT
existing	Lithuania	ENTSO-E RG BALTIC	Belarus	IPS/UPS	no	sync.	HVAC	400	GT
new	Italy	ENTSO-E RG CE	Tunisia	Maghreb Pool	no	sync.	HVDC (sea)	1000	all
new	Italy	ENTSO-E RG CE	Montenegro	ENTSO-E RG CE	yes	sync.	HVDC (sea)	1000	all
new	Italy	ENTSO-E RG CE	Algeria	Maghreb Pool	no	sync.	HVDC (sea)	500-1000	all
new	Italy	ENTSO-E RG CE	Albania	sync. ENTSO-E RG CE	yes	sync.	HVDC (sea)	500-1000	all
new	Poland	ENTSO-E RG CE	Belarus	IPS/UPS	no	asnyc.	B2B	600-1000	all
new	Romania	ENTSO-E RG CE	Turkey	sync. ENTSO-E RG CE	not yet	sync.	HVDC (sea)	n.a.	all
new	Romania	ENTSO-E RG CE	Serbia	ENTSO-E RG CE	yes	sync.	HVAC	1500	all

Table 73: Transmission options for electricity import into the EU from new fossil fired power plants outside the EU

Six options are based on utilization of existing interconnections. In four of these, the remaining free transmission capacities of the links, though, are not enough to secure electricity export from large CCGT or coal-fired power plants with more than 400 MW. For these four electricity export options into the EU, only investment in new natural gas-fired turbines with a capacity of 150 MW is considered. These four electricity transmission options are:

- from Russia to Estonia
- from Russia to Finland
- from Serbia to Hungary
- from Belarus to Lithuania.

Only the existing grid connections between Turkey and the two EU countries Greece and Bulgaria will reliably offer sufficient transfer capacity for new large power plants to be installed in Turkey, but not before full integration of Turkey into the ENTSO-E network. All six identified existing connections are HVAC links, apart from the existing HVDC back-to-back link from Russia to Finland.

For the additional seven transmission options for new grid connections, it is assumed that all provide at least 1000 MW transmission capacity for electricity import into the EU. For the connections from Albania and Algeria this may be at least the case after having finished the second expansion stage (i.e. 2 x 500 MW). Five potential new connections are HVDC lines, one based on HVDC back-to-back (Belarus - Poland) and one is an HVAC connection extension from Serbia to Romania.

The new power plants associated with the identified electricity transmission options into the EU would be hosted by the following eight non-EU countries:

Non-EU country	Member of Energy Community
Albania	Yes
Algeria	No
Belarus	No
Montenegro	Yes
Russia	No
Serbia	Yes
Tunisia	No
Turkey	Observer status, Membership envisaged

Table 74: Non-EU countries with transmission options for electricity import into EU

With regard to the political and regulatory environment for power plant investments in these countries, their membership in the Energy Community is of significance and is denoted in Table 74. Turkey has the status of an observer in the Energy Community, but membership is sought on the part of Turkey as well as on the part of the EU. It may thus be assumed that potential power plant investments in Turkey will even now already have to comply with Energy Community rules in order not to risk becoming a stranded investment after the Turkey's accession. For this reason, our analysis of the regulatory environment in Turkey considers Turkey as already being a member of the Energy Community.

6.1.2 Fuel Availability for New Power Plants

In the next step, the identified transmission options (cf. Table 73) and their associated power plant investment options in non-EU countries are further assessed regarding fuel availability.

According to Table 73, for Russia only GT power plants are considered. For all other countries, also lignite- and hard coal-fired power plants are a priori an option. Whereas hard coal could be imported, firing lignite is economically feasible only for power plants in the neighbourhood of lignite deposits. This is not the case in Algeria, Tunisia and Belarus. In Albania, lignite resources are available in principle, however fuel quality is poor and specific extraction costs are almost double per MWh energy content the price of imported hard coal. Thus lignite power plants in Albania are not considered further for this study.

In the case of Turkey, a new power plant associated with the envisaged connection from Turkey to Romania would be sited too far from Turkish lignite resources. However, lignite mines in the Trakya basin on the Turkish part of the European tectonic plate (Thrace region) close to EU neighbours could provide fuel for power plants dedicated for electricity export to Bulgaria or Greece. Other countries with lignite resources are Montenegro and Serbia. Serbia could use lignite for a power plant dedicated for electricity export to Romania.

In Montenegro and Albania, no natural gas fired power plants are feasible at present due to the lack of a natural gas supply. For both countries, the prospects for such a supply depend heavily on future realisation of the Trans Adriatic Pipeline (TAP) project. TAP is planned to transport gas from the Caspian region via Greece and Albania and across the Adriatic Sea to southern Italy and further into Western Europe.

TAP competes with the Nabucco West pipeline for opening the new Southern Gas Corridor to Europe and establish a new market outlet for natural gas from the Caspian Sea. A decision is scheduled for 2013. Gas from the Azerbaijani Shah Deniz-2 project is regarded as the main source for the TAP project, but will not be available before 2018. For transport to Montenegro, a connection to the Ionian Adriatic Pipeline (IAP) project would be necessary. IAP is another pipeline project planned to connect Albania and Montenegro with Croatia. For the timeframe of this study up to the end of the third ETS in 2020, the maturities of the natural gas pipeline projects are assessed to be insufficient for investment decisions for any natural gas power plants in Albania or Montenegro. But all other non-EU countries considered can either import natural gas via pipeline or even use indigenous natural gas production like in Algeria, Tunisia and Russia.

In summary, Table 75 adds to the power plant options as listed in Table 73 the fossil fuel availabilities as discussed above.

existing / new	EU country	non-EU country	types of power plant	fossil fuel sources for non-EU power plant: lignite	hard coal	natural gas
existing	Bulgaria	Turkey	all	indigenous	import	import
existing	Greece	Turkey	all	indigenous	import	import
existing	Estonia	Russian Federation	GT	-	-	indigenous
existing	Finland	Russian Federation	GT	-	-	indigenous
existing	Hungary	Serbia	GT	-	-	import
existing	Lithuania	Belarus	GT	-	-	import
new	Italy	Tunisia	all	-	import	indigenous
new	Italy	Montenegro	all	indigenous	import	-
new	Italy	Algeria	all	-	import	indigenous
new	Italy	Albania	all	not viable	import	-
new	Poland	Belarus	all	-	import	import
new	Romania	Turkey	all	-	import	import
new	Romania	Serbia	all	indigenous	import	import

Table 75: Transmission options for electricity import into the EU from new fossil fuel power plants outside the EU and the associated fuel availability

6.1.3 Political and regulatory constraints in non-EU countries

The EU has set up a Baltic Energy Market Interconnection Plan (BEMIP) for integration of the Baltic States into the EU energy networks. A long term political goal is for the Baltic countries to desynchronise from the Russian network and synchronise with the EU network [ELFORSK]. The target year for full implementation of the common Baltic market integrated with Nord Pool has been fixed as 2015 (see also 4.2.8.2). Due to this political development, new power plants in Russia dedicated for electricity export to the Baltic States are no longer a practical proposition. Instead they face the risk of becoming decoupled after network desynchronisation. Furthermore, with the integration of the Baltic countries into the ENTSO-E networks, also the configuration of the Baltic electricity market will be adjusted accordingly [CESI], so the Baltic and Russian electricity market designs will completely differ due to their specific characteristics and features. This will complicate trading and cross-border transmission capacity management (cf. 4.2.8.2), as is already observable today for the cross-border transmission capacities between Russia and Finland, for which there are no prospects for investors in transmission capacity access. For these reasons, the option to import electricity from new power plants in ***Russia*** to the EU is not considered to be realistic and is eliminated from further consideration.
A similar situation due to decoupling from the IPS/UPS system of the Baltic countries arises with ***Belarus***. Additionally, the political situation in Belarus makes it difficult for investors to gain enough confidence for financing power plant projects. An example is given in section 8.2. Thus also new power plants in Belarus for electricity export to the EU are not taken into

account further in this study as they are not a realisable investment option until 2020.

6.2 Identification and Quantification of Country-Specific Conditions

The overall objective of this study is to analyse whether power plants built in countries adjacent to EU for electricity export for final consumption within the EU have a significant competitive advantage due to the fact that there are no carbon costs for electricity generation outside the EU.

In a first stage we calculate in the study with our model the levelized electricity generation cost (LEC). Furthermore, we also determine the maximum additional “rate of return” that an investor could obtain up to the point where the potential advantage provided by the avoided CO_2 costs is just offset by higher returns.

However, the LEC does not provide a complete picture of the potential competitive advantage. To round this off another two aspects must be included in the considerations:

- possible country risks
- cost for electricity transport from the power plant to the EU grid.

Taking into consideration the project cost incurred by these two aspects may reduce the potential advantage provided by avoided CO_2 costs. For the sake of completeness these two aspects are discussed and analysed in the following two sections.

6.2.1 Consideration of country risks

A key question when investing in power plant projects in the European Union’s adjacent countries, in particular in Eastern Europe or in North Africa, relates to whether there is more risk that must be addressed and to what extent. In this context, we must identify the types of risks, try to assess their likelihood of occurrence and quantify their impact on project costs and returns. Of course, this must always be done for each project, but in the following these aspects are addressed in general terms only.

In our case, country risks may include political risks, sovereign credit default risks, economic risks, currency risks and transfer risks.

The political situations in Eastern European and North African countries are undergoing a transition and *political risks* are to be expected, like subversion of the political system, insurgency or the risk of nationalization in the course of regime change. The general expectation, though, is that such a change will occur gradually rather towards more democracy and a free market economy, at least over the medium to long term. Hence, we consider the scale of the impact of political risks on investments for power plants with long service lives built for power export to EU will be low to medium.

Economic risks and sovereign credit default risks are actually unpredictable and can occur in European as well as in non-European countries in the course of global financial and economic turmoil. If such an event happens in a single country it might not have significant influence on power plant projects that supply electricity within the EU. In contrast, the income coming from the EU will be welcome. Hence, these risks, too, would appear to have only a limited impact on the investment.

Currency risk and transfer risk of revenues is the most significant risk when investing in foreign countries. However, in our case such a risk is actually non-existent as the electricity exported into the EU grid will be paid by the receiver within the EU. Hence, revenues must not be retransferred and will remain at the disposal of the investor in a secure country of his choice.

In summary, this means that country risks for power plant projects in adjacent EU countries in Eastern Europe or North Africa can be regarded as medium to low or, in part, as non-existent. Nevertheless, investors and creditors will always consider some risk in their decision. Therefore, at least a quantification of the magnitude of country risks will be helpful. A useful instrument for this purpose is provided by the rating agencies.

The creditworthiness of a country or entity is evaluated by rating agencies. In general, the *rating* is an evaluation of the debtor's ability to pay back the debt and the likelihood of default. Credit ratings are expressed in rating classes as shown in Table 76. These ratings are considered to be investment grade, which means that the security or the entity being rated carries a level of quality that many institutions require when considering overseas investments. Ratings that fall under "BBB" are considered to be speculative or "junk". Updated ratings are listed in Table 76.

Agency		**Grade**	**Risk**
Moody's	**Standard & Poor's**		
Aaa	AAA	Investment	Lowest Risk
Aa	AA	Investment	Low Risk
A	A	Investment	Low Risk
Baa	BBB	Investment	Medium Risk
Ba, B	BB, B	Junk	High Risk
Caa/Ca/C	CCC/CC/C	Junk	Highest Risk
C	D	Junk	In Default

Table 76: Rating classes

In this context, it must be pointed out that the ratings are always snapshot views of a country's economic situation and are readjusted if changes occur. Updated ratings for countries are available, e.g. in the British newspaper [The Guardian].

Credit insurance companies as Hermes in Germany usually rely on the “OECD arrangement on officially supported export credits” in defining their credit default premiums. In this document countries are classified in 8 country risk categories 0 to 7. Countries of the category 0 are the high income OECD countries with country risk zero. All the others have a higher classification which means a higher country risk. For instance the following countries are currently classified as follows: Spain 0; Poland 0, Bulgaria 4, Russia 3, Turkey 4, Morocco 3, Ukraine 7. (See http://www.oecd.org/tad/exportcredits/cre-crc-current-internet-rev1.pdf)

The risk rates are calculated with a model for Commercial Interest Reference Rates (CIRRs) for each country separately, considering several financial parameters. The main risks included are the transfer risk and currency risk. In our case we are of the opinion that both are only partly relevant because there is no risk of transfer since the revenues are paid within the EU and the currency risk is limited only to the services for the power plant provided by locals such as operating staff, civil works etc.

A widely used approach for risk consideration is to include an increment as a risk premium in the weighted average cost of capital (WACC) that is used as discount rate. This is an increment above a standard rate. In our approach, the WACC includes three elements: the risk-free rate, the venture premium for the particular investment and the country risk premium. The latter two are considered only for the equity share of capital expenditures.

The premiums are usually expressed in basis points (Bps). A 1%age point is equal to 100 basis points and is used to denote the increment above a standard risk-free rate. Basis point 300, for instance, means that 3%age points must be added to the standard rate. In Table 77, estimates of the country risk premiums for corporate bonds and for government bonds in basic points are shown depending on the country ratings.

Rating class	Aaa	Aa1	Aa2	Aa3	A1	A2	A3	Baa1	Baa2	Baa3	Ba1	Ba2	Ba3	B1	B2	B3	Caa
Corporate Bonds, Bps	0	60	65	70	80	90	85	120	130	145	250	300	400	450	550	650	750
Government Bonds, Bps	0	75	85	90	100	125	135	150	175	200	325	400	525	600	750	850	900
Source: San José State University Dpt of economics, USA, Based upon information from Moody's and Bondonline.com																	

Table 77: Country risk premiums by rating class

The figures in the table above consider all the risk to their full extent. However, we mentioned above that country risks for power plant projects for electricity exports to EU have only a limited impact on the investment and the most important *currency and transfer risks* are non-existent in our case. Therefore, the country risk premiums will be low.

As a consequence, we can conclude that the advantage of the avoided CO_2 costs leaves a sufficient margin for increasing the rate of return and provide a significant competitive advantage for envisaged power plant projects in adjacent EU countries. It is to be noted, however, that in order to retain a competitive advantage the investor can draw down only a part of this margin that is within his own judgment.

6.2.2 Influence of transmission costs on the viability of the investment

The cost for transport of the generated power into the EU's transmission system are calculated using the decision making model. This transmission cost will be especially high for power plants located in regions with transmission grids that are not synchronized with the grid of the neighbouring EU country and that have thus to install costly converter stations. In any case, feeding power into the EU grid will have cost implications on top of the pure generation cost.

In section 4.2.6.2 the required technical infrastructure and typical capital expenditures for such transport systems are described. In the following Table 78 we roughly calculate and compare the advantage from avoided CO_2 cost versus transport cost for the power plant types considered in the study in order to determine the actual advantages after transmission cost.

In the table, the calculation is conducted for a typical case of transmission via an HVDC system as an example under the following constraints:

- CAPEX for an 800 MW HVDC transmission system including the two converter stations and a transmission line of 50 km between the power plant and the EU 380 kV grid €508m
- lifetime 35 years, discount rate on real terms 6%/a
- system losses 2%/a

Based on these assumptions, the following specific capacity cost and electricity cost are calculated:

- capacity cost 53 €/kWa referred to transmitted power in kW
- electricity cost 0.80 €/MWh referred to the transmitted energy in MWh

Example 1: Transmission cost for base load of 800 MW 6,000 GWh/a:

C= 53 x 800,000 +0.8 x 6,000,000 = 47,200,000 €/a

Specific cost: 47,200,000 /6,0000,000 = 7.87 €/ MWh

Example 2: Transmission cost for peak load of 150 MW 225 GWh/a:

C= 53 x 150,000 +0.8 x 225,000 = 8,130,000 €/a

Specific cost: 8,130,000 /225,000 = 36.13 €/ MWh

The results for the three scenarios are depicted in Table 78 and visualized in Figure 91. The outcome shows the remaining benefit from the avoided CO_2 cost after deduction of the transmission cost. Of course, the technical feasibility and cost implications must be determined for each project separately.

Item	Unit	Lignite base	Hard Coal base	CCGT base	CCGT in'diat-	SCGT peak
		7,500 h/a	7,500 h/a	7,500 h/a	4,500 h/a	1,500 h/a
Basic constraints	t_{Co2} / MWh_e	0.91	0.74	0.36	0.36	0.59
Annual CO_2 Emissions	kt_{Co2} / a	5,466	4,459	2,163	1,298	134
Transmission cost	mln € / a	47.48	47.48	47.48	45.56	8.18
Scenario A						
Levelized spec. CO_2 cost	€ / t	27.47	27.47	23.61	23.61	23.61
Avoided annual CO_2 cost	mln € / a	150.17	122.48	51.06	30.64	3.15
Benefit CO_2 cost - transmissions cost	mln € / a	**102.68**	**75.00**	**3.58**	**(14.93)**	**(5.03)**
Scenario B						
Levelized spec. CO_2 cost	€ / t	38.56	38.56	32.15	32.15	32.15
Avoided annual CO_2 cost	mln € / a	210.78	171.92	69.52	41.71	4.30
Benefit CO_2 cost - transmissions cost	mln € / a	**163.30**	**124.44**	**22.04**	**(3.85)**	**(3.89)**
Scenario C						
Levelized spec. CO_2 cost	€ / t	44.10	44.10	35.56	35.56	35.56
Avoided annual CO_2 cost	mln € / a	241.07	196.63	76.91	46.14	4.75
Benefit CO_2 cost - transmissions cost	mln € / a	**193.58**	**149.14**	**29.42**	**0.58**	**(3.43)**

Table 78: Power transmission cost vs. avoided CO_2 cost

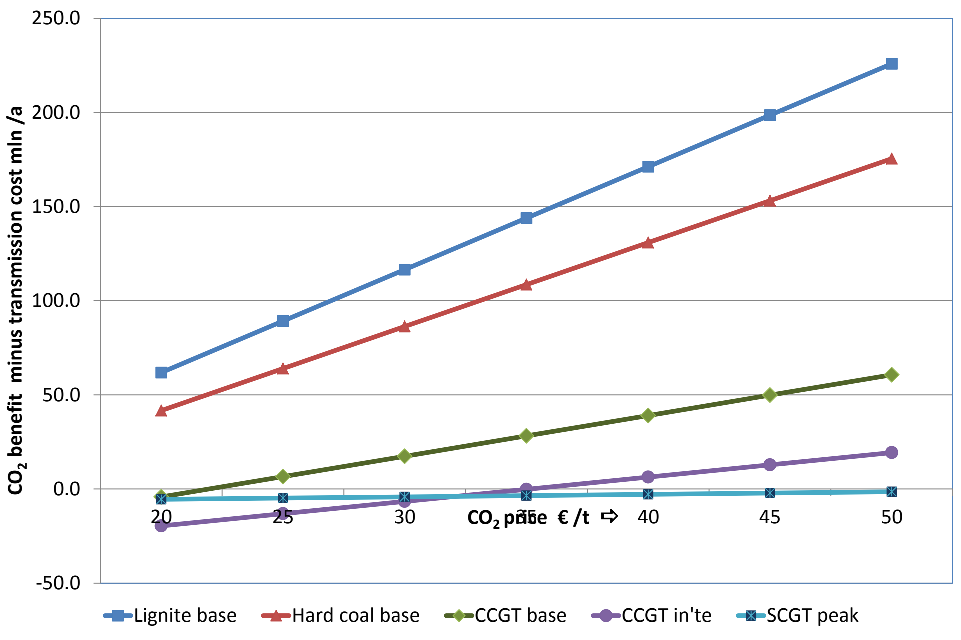


Figure 91: Benefit of avoided CO_2 cost minus transmission cost

From the outcome of the calculations and the results depicted in the table and figure above, it is evident that only coal-fired baseload power plants with high CO_2 emissions prove to have a significant advantage from the avoided CO_2 costs that by far outweighs transmission cost. In contrast, the benefit of even baseload gas-fired CCGT plants with lower CO_2 emissions appear to be moderate. The transmission cost for intermediate and peak load power cannot be compensated by the avoided CO_2 costs for the illustrated case.

The calculations are for grids that are not synchronized with EU grids and that thus require an extensive HVDC link (subsea cable or B2B) to be built. The impact of the transmission costs may be less for power plant sites in areas with grids synchronized with the EU grids that can employ less expensive HVAC technology; nevertheless, the general trend of this outcome will not be reversed.

> A predominance of transmission costs over CO_2 costs is also effective for *renewable energy projects*, for two reasons:
>
> 1. There is no advantage for renewable power from avoided CO_2 costs as is the case for fossil power.
> 2. Due to their low capacity factor (full load operating hours) the specific transmission cost will be high for plants outside the EU if such cost are to be charged.

6.3 Prospects for Investments outside the EU

Assessments and evaluations of investments for power plant projects are prepared using the developed model pair-wise for specific countries in- and outside the EU. However, in these calculations there are many variables dependent on the countries and some important aspects may not appear sufficiently clearly.

So before starting calculation and evaluation of the results for power plant investment in specific countries, some discussions of important aspects in parametric form which are applicable independent of the specific country are presented and discussed in this section. The calculations are conducted with a simplified model to determine the electricity generation cost.

6.3.1 Competitive advantage provided by avoided carbon cost

The main incentive for investing in power plants outside the EU is provided by the avoided CO_2 cost. The magnitude of this advantage is shown in the following Table 79, Table 80 and Table 81 for the three scenarios.

The second block of the tables show the electricity generation cost including and excluding CO_2 cost. As becomes evident for all three scenarios, the difference is quite high for coal-fired power plants while it is moderate for gas-fired CCGT power plants in base load mode. For peak load plants, the advantage is marginal only. CCGTs operated in intermediate load have still some advantage but not to the same extent as coal-fired power plants.

In the third block of the tables, also the maximum discount rate (based on WACC) is shown for which the electricity generation cost excluding CO_2 cost would become equal to that including CO_2 cost. This value is termed ‘break even WACC’, and ‘break even discount rate’ in the further context of this study. In all three scenarios, these break-even discount rates are quite high. In this context it is worth noting that for an investor the return on equity (RoE) is most important. With the given shares on assets that are at the basis of the calculation of the WACC, the RoE is roughly twice as high as the discount rate (see Figure 92).

However, in order to have a competitive advantage the investor will draw down only a part of this margin so that the electricity generation cost will be lower compared to those of the same type of power plant inside the EU.

Scenario A	Unit	Lignite base	Hard coal base	CCGT base	CCGT int'ate	SCGT peak
Fuel cost	€/MWh$_t$	7.19	15.32	37.20	37.78	41.54
Fuel cost	Mio € / a	124.7	161.8	196.2	119.5	22.7
CO_2 cost	€ / t	27.47	27.47	23.61	23.61	23.61
Discount rat, in nominal terms (WACCn)	-	7.5%	7.5%	7.5%	7.5%	7.5%
CO_2 cost	Mio € / a	189.3	99.2	25.1	15.1	2.6
Levelized electricity cost, including CO_2 cost	€/MWh$_e$	63.09	74.53	86.06	89.60	170.96
Levelized electricity cost, excluding CO_2 cost	€/MWh$_e$	38.82	54.12	77.55	81.09	156.94
CO_2 cost	Mio € / a	0.00	0.00	0.00	0.00	0.00
Discount rate, in nominal terms (WACCn)	-	18.6%	18.0%	20.2%	15.4%	15.3%
Levelized electricity cost, excluding CO_2 cost	€/MWh$_e$	63.09	74.53	86.06	89.60	170.96

Table 79: Influence of CO_2 cost on levelized electricity cost, Scenario A

Scenario B	Unit	Lignite base	Hard coal base	CCGT base	CCGT int'ate	SCGT peak
Fuel cost	€/MWh$_t$	6.84	14.56	35.75	36.33	40.09
Fuel cost	Mio € / a	118.5	153.8	188.5	114.9	21.9
CO_2 cost	€ / t	38.56	38.56	32.15	32.15	32.15
Discount rate, in nominal terms		7.5%	7.5%	7.5%	7.5%	7.5%
CO_2 cost	Mio € / a	265.8	139.3	34.2	20.5	3.6
Levelized electricity cost, including CO_2 cost	€/MWh$_e$	72.10	81.12	86.55	90.09	171.76
Levelized electricity cost, excluding CO_2 cost	€/MWh$_e$	38.03	52.47	74.96	78.50	152.67
CO_2 cost	Mio € / a	0.00	0.00	0.00	0.00	0.00
Discount rate, in nominal terms	-	23%	22%	24%	18%	14%
Levelized electricity cost, excluding CO_2 cost	€/MWh$_e$	72.10	81.12	86.55	90.09	171.76

Table 80: Influence of CO_2 cost on levelized electricity cost, Scenario B

Scenario C	Unit	Lignite base	Hard coal base	CCGT base	CCGT int'ate	SCGT peak
Fuel cost	€/MWh$_t$	5.97	12.71	33.41	33.99	37.74
Fuel cost	Mio € / a	103.5	134.2	176.1	107.5	20.7
CO_2 cost	€ / t	44.10	44.10	35.56	35.56	35.56
Discount rat, in nominal terms		7.5%	7.5%	7.5%	7.5%	7.5%
CO_2 cost	Mio € / a	303.9	159.3	37.9	22.7	3.9
Levelized electricity cost, including CO_2 cost	€/MWh$_e$	75.07	81.22	83.59	87.13	166.89
Levelized electricity cost, excluding CO_2 cost	€/MWh$_e$	36.10	48.45	70.78	74.32	145.77
CO_2 cost	Mio € / a	0.00	0.00	0.00	0.00	0.00
Discount rate, in nominal terms	-	25%	24%	26%	19%	15%
Levelized electricity cost, excluding CO_2 cost	€/MWh$_e$	75.07	81.22	83.59	87.13	166.89

Table 81: Influence of CO_2 cost on levelized electricity cost, Scenario C

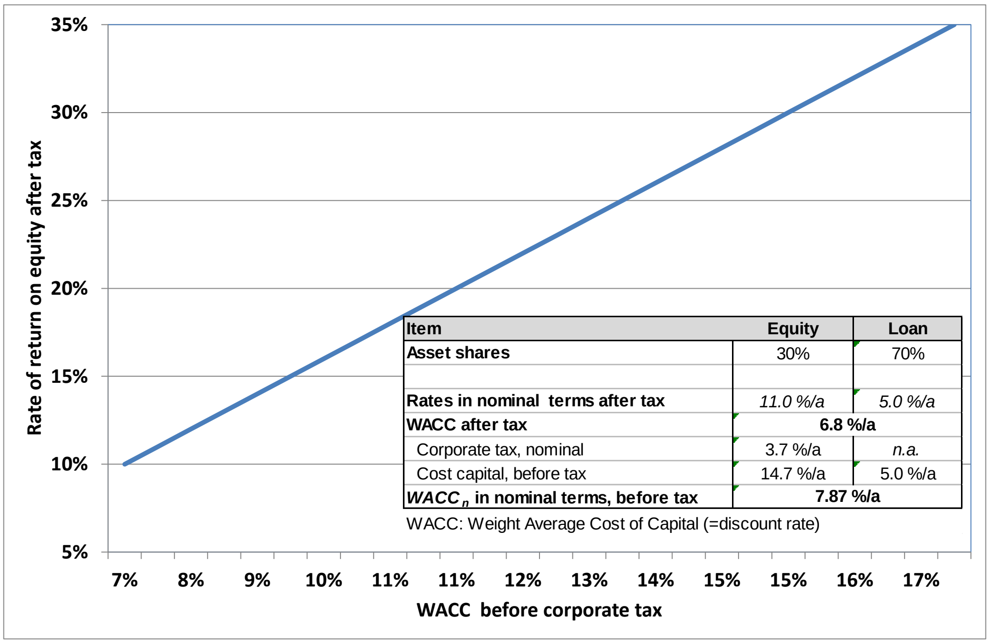


Figure 92: Rate of return on equity vs. discount rate

6.3.2 Competitive advantage provided by marginal cost

Investors of power plants will first try to sell the bulk of their electricity production by power purchase agreements with TSO, traders and large consumers. The remaining production will be offered on the power exchange. Offers on the power exchange are usually made on the basis of the marginal cost plus a moderate portion of the fixed productions cost so that the offer will be lower than the market clearing point and will be accepted. CO_2 costs are marginal cost. As they are avoided they provide a significant additional advantage to power plants outside the EU.

As Table 82, Table 83 and Table 84 reveal, again this advantage is significant for coal-fired power plants in all three scenarios, while it decreases for gas-fired power plants. This is generally a disadvantage of gas-fired power plants, with or without CO_2 costs. The reason is that fuel costs are marginal costs as well and, due to the higher price for gas in most cases, marginal costs are high.

Scenario A	**Unit**	**Lignite base**	**Hard coal base**	**CCGT base**	**CCGT int'ate**	**SCGT peak**
Electricity generation cost, *including* CO_2 cost						
Total	€/MWh$_e$	63.09	74.53	86.06	89.60	170.96
Only marginal cost	€/MWh$_e$	41.91	55.00	78.39	79.42	139.63
Electricity generation cost, *excluding* CO_2 cost						
Total	€/MWh$_e$	38.82	54.12	77.55	81.09	156.94
Only marginal cost	€/MWh$_e$	17.64	34.58	69.88	70.91	125.61
Note: Fuel prices as given for this scenario		**Note:** Calculated with the same discount rate				

Table 82: Share of marginal costs in total electricity generation cost, Scenario A

Scenario B	**Unit**	**Lignite base**	**Hard coal base**	**CCGT base**	**CCGT int'ate**	**SCGT peak**
Electricity generation cost, i*ncluding* CO_2 cost						
Total	€/MWh_e	72.10	81.12	86.55	90.09	171.76
Only marginal cost	€/MWh_e	50.92	61.59	78.88	79.91	140.43
Electricity generation cost, *excluding* CO_2 cost						
Total	€/MWh_e	38.03	52.47	74.96	78.50	152.67
Only marginal cost	€/MWh_e	16.85	32.94	67.29	68.32	121.34
Note: Fuel prices as given for this scenario		**Note:** Calculated with the same discount rate				

Table 83: Share of marginal costs in total electricity generation cost, Scenario b

Scenario B	**Unit**	**Lignite base**	**Hard coal base**	**CCGT base**	**CCGT int'ate**	**SCGT peak**
Electricity generation cost, i*ncluding* CO_2 cost						
Total	€/MWh_e	72.10	81.12	86.55	90.09	171.76
Only marginal cost	€/MWh_e	50.92	61.59	78.88	79.91	140.43
Electricity generation cost, *excluding* CO_2 cost						
Total	€/MWh_e	38.03	52.47	74.96	78.50	152.67
Only marginal cost	€/MWh_e	16.85	32.94	67.29	68.32	121.34
Note: Fuel prices as given for this scenario		**Note:** Calculated with the same discount rate				

Table 84: Share of marginal costs in total electricity generation cost, Scenario C

6.4 Presentation and discussion of the country specific results

The power plant investment options in non-EU countries that qualified under the decision tree procedures (see section 6.1) for potential electricity import into the EU are now analysed to establish their competitiveness vis-à-vis alternative power plant investments in the neighbouring EU country. Comparisons are made on the basis of levelized electricity costs (LEC) and are performed separately for each market segment, i.e. for base load, intermediate load and peak load power plants. The decision making model as explained in chapter 4 is applied for the LEC calculation. An example of such a calculation for the country-pair Italy-Tunisia is shown in Table 85. For the remaining country-pairs, calculations are shown in Annex V.

Calculations for non-EU countries are done in a first run without adding any country-specific risk premiums. Under such conditions, the levelized CO_2 costs (LCO_2) for ETS certificates of a new EU power plant mean a competitive advantage for the power plant in the non-EU country in terms of a lower LEC. On the other hand, in the non-EU country levelized transmission costs (LTC) accrue for electricity export to the EU. The extent to which LCO_2 outweighs LTC usually determines the competitiveness between EU and non-EU country investment, provided that other factors impacting the LEC, such as fuel costs, tax rates, etc. don't differ too much between the two countries.

In the example below (Table 85), for instance in Scenario A in the base load case, 20.2 €/MWh_e LCO_2 for a hard coal power plant in Italy stands vis-á-vis only 9.4 €/MWh_e LTC for a hard coal power plant in Tunisia. Accordingly, the LEC is lower in Tunisia than in Italy in this case.

The model selects the most competitive power plant with the least LEC that is outside the EU but it is not necessarily of the same type as the one inside the EU. But for the case of Italy and Tunisia it is always hard coal power plant in base load for both countries.

In such a case, though, the competitive advantage of the non-EU project holds only under the assumption that the investor will be satisfied with a WACC of 5.6% in real terms. As it is calculated without any country-specific risk premium, the WACC of Tunisia is then almost identical to that of Italy (5.5%), the difference being only due to the differing corporate tax rates.

But in reality the investor would like to be compensated for higher investment risks outside the EU through higher returns. Consequently, the competitiveness of the non-EU power plant depends finally on a low enough benchmark value for the WACC that is applied for appraisal of the non-EU investment.

The WACC that the non-EU investment can just afford in order to remain marginally competitive with the respective EU power plant is shown in the column “non-EU breakeven”. It is the result of a calculation in which the non-EU WACC is set accordingly in order to obtain the same LEC for the non-EU power plant as for the EU power plant. In base load in Scenario A this is the case at a WACC of 12.0% inflation-adjusted (see Table 85). An investment consortium being satisfied with an ROI not higher than 12% will be able to compete in base load with the Italian power plant investment. However, the investment consortium would with such a WACC benchmark go for a less capital-intensive CCGT power plant in Tunisia instead of going for the hard coal power plant, which would no longer be the best choice for base load under such conditions.

For a power plant investment in Tunisia planned to supply base load in Italy, the following situation holds in Scenario A:

- without any country-specific risk premium (WACC = 5.6%) a ***hard coal power plant*** would be the most competitive investment
- at a ***‘break even WACC’*** of 12.0%, a ***CCGT*** would be the most competitive investment with just the same LEC as the Italian power plant alternative.

In actual fact, the non-EU investment would opt for a WACC (and for the most competitive specific type of power plant at this WACC) that is above the minimum WACC (no country-specific risk) but close below the breakeven WACC in order to achieve a strategic advantage of lower LEC compared to the EU power plant.

In reality, for the non-EU investment, a WACC value (and the most competitive specific type of power plant at this WACC) would have to be used in investment calculations, that is above the minimum WACC in order to include a country-specific risk premium, but that is close below the breakeven WACC in order to achieve a strategic advantage of still lower LEC compared to the EU power plant. The investor has to plan for a WACC somewhere within this range, otherwise the non-EU investment would not be feasible.

The competitiveness of the non-EU power plant stems in the example above from the fact that the LCO_2 accruing in the EU country exceeds the LTC accruing in the non-EU country.

The dominance of LCO_2 over LTC, though, diminishes when the case is changed from base load to intermediate load and to peak load. This is for two reasons: First of all, only CO_2 saving power plant technologies with low LCO_2 are applied in peak load (GT) and particularly in intermediate load (CCGT). This becomes obvious from Annex III.

Secondly, the CAPEX for the transmission investment levelizes over much fewer full load hours in intermediate and peak load than in base load. That's why LTCs generally increase for intermediate load power plants and particularly for peak load power plants (cf. also section 6.4.1). This is also apparent from Table 85. As a result of both effects – reduced LCO_2 and increased LTC – Tunisian peak load GTs cannot compete with Italian ones in all three scenarios, even if no country-specific risk premium is factored in. Accordingly, no WACC for breakeven with LEC can be found.

A similar trend may also be noted for the other analysed country pairs (cf. Annex V): New peak load power plants and, in part, also new intermediate load power plants in the non-EU countries dedicated for electricity export to the EU have problems competing with the respective investment alternatives within the EU. The overall picture for all cases and all country-pairs is analysed in section 6.4.2 and compared between the scenarios. Finally, in section 6.4.3 a list of the most promising investment opportunities is presented. But prior to this, underlying country-specific assumptions in the model are introduced in section 6.4.1.

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Tunesia	Tunesia	Italy	Tunesia	Tunesia	Italy	Tunesia	Tunesia
		Hard Coal USC-PC	Hard Coal USC-PC	CCGT -	CCGT	CCGT	CCGT	GT	GT	GT
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	82.1	69.3	82.1	100.8	86.1	100.8	179.3	189.9	n.a.
Levelized marginal cost	€ / MWh_e	55.3	34.6	50.5	85.5	53.9	51.9	134.5	88.5	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	20.2	0.0	0.0	8.5	0.0	0.0	12.4	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	9.4	18.2	n.a.	17.9	28.1	n.a.	64.6	n.a.
WACC (discount rate, real)	%	5.5%	5.6%	12.0%	5.5%	5.6%	10.9%	5.5%	5.6%	n.a.
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Tunesia	Tunesia	Italy	Tunesia	Tunesia	Italy	Tunesia	Tunesia
		Hard Coal USC-PC	Hard Coal USC-PC	CCGT -	CCGT	CCGT	CCGT	GT	GT	GT
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	88.6	67.8	88.6	101.1	84.2	101.1	179.8	187.2	n.a.
Levelized marginal cost	€ / MWh_e	61.8	33.0	48.7	85.9	52.1	50.6	135.0	85.8	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	28.4	0.0	0.0	11.6	0.0	0.0	16.9	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	9.4	23.3	n.a.	17.9	29.1	n.a.	64.6	n.a.
WACC (discount rate, real)	%	5.5%	5.6%	15.9%	5.5%	5.6%	11.4%	5.5%	5.6%	n.a.
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Tunesia	Tunesia	Italy	Tunesia	Tunesia	Italy	Tunesia	Tunesia
		Hard Coal USC-PC	Hard Coal USC-PC	CCGT -	CCGT	CCGT	CCGT	GT	GT	GT
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	88.6	63.8	88.6	97.9	81.2	97.9	175.1	182.8	n.a.
Levelized marginal cost	€ / MWh_e	61.7	29.0	47.4	82.6	49.1	48.8	130.3	81.4	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	32.3	0.0	0.0	12.8	0.0	0.0	18.7	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	9.4	24.0	n.a.	17.9	28.2	n.a.	64.6	n.a.
WACC (discount rate, real)	%	5.5%	5.6%	16.5%	5.5%	5.6%	11.0%	5.5%	5.6%	n.a.

Table 85: Main results from the decision making model for competing power plant investments between Italy and Tunisia

6.4.1 Underlying country-specific assumptions

After having explained by way of example the outcomes of the model, now the assumptions underlying the model for the non-EU countries are introduced in this section. These assumptions concern costs for cross-border transmission into the EU, fuel prices in the non-EU countries as well as further country specific model inputs, such as taxes and labour costs.

In our decision making model, transmission costs are included via the specific CAPEX for each transmission option. They thus act as fixed costs within the model. That means they are costs that arise for the availability of the transmission capacity, independent of the power plant's actual generation. The lower the annual full load hours of the power plant, the higher the specific/levelized transmission cost per generated kWh. This means increased levelized transmission cost for intermediate and particularly for peak load power plants compared to base load power plants.

Furthermore, the CAPEX considered for transmission depends on the power plant's capacity in the model. Accordingly, a 150 MW GT is not burdened with the whole CAPEX of a 1000 MW transmission project, but only with 15% of it to match the transmission capacity part to be reserved for the GT.

In general, it must be emphasized, though, that the figures for transmission CAPEX factored into our decision making model have a relatively low accuracy compared with the electricity generation cost free power plant (i.e. up to the plant boundary). This is also because there is insufficient information on transmission distances and capacities, since costs for transmitting power from potential power plant sites outside the EU and transmission CAPEX figures can vary widely from project to project. Additionally, CAPEX for converter stations has experienced an increasing trend recently, among other things because of a greater number of ongoing HVDC projects worldwide. Our estimates of transmission CAPEX are based on specific CAPEX values as given in section 4.2.6.2 and result in specific CAPEX values (per GW transmission capacity) for country pairs as shown in Table 86.

For non-EU power plants that would like to export electricity to the EU via <u>existing</u> interconnections, figures for transmission fees are generally not available, so an appraisal has been made on the basis of the current replacement value of the existing line. Since the analysed transmission options that are based on existing lines are all HVAC interconnections, the assigned CAPEX values for replacement (cf. Table 86) and thus the resulting levelized transmission costs are relatively low.

existing / new	EU country	non-EU country	sync./async.	type of connection	types of power plant	CAPEX [Mio €/GW]	fossil fuel prices in 2010 [€/MWh$_t$] lignite	hard coal	natural gas
existing	Bulgaria	Turkey	sync.	HVAC	all	43	6	11.81	30.31
existing	Greece	Turkey	sync.	HVAC	all	65	6	11.81	30.31
existing	Hungary	Serbia	sync.	HVAC	GT	65	-	-	29.75
new	Italy	Tunisia	sync.	HVDC (sea)	all	1070	-	11.71	22.64
new	Italy	Montenegro	sync.	HVDC (sea)	all	1115	10	11.71	-
new	Italy	Algeria	sync.	HVDC (sea)	all	998	-	11.71	22.64
new	Italy	Albania	sync.	HVDC (sea)	all	1034	-	11.71	-
new	Romania	Turkey	sync.	HVDC (sea)	all	1160	-	11.81	30.31
new	Romania	Serbia	sync.	HVAC	all	65	6	11.71	30.71

Table 86: Transmission options with associated specific transmission CAPEX and fuel prices in non-EU countries in 2010

From Table 88 to Table 96 below, it becomes evident that LTC values for base load options with existing transmission lines are in the range of about 0.5 €/MWh$_e$. For intermediate load and particularly for peak load these increase up to about 3.5 €/MWh$_e$. Thus, for existing transmission options, LTC does not have a serious negative impact on the competitiveness of the non-EU power plant, at least not in base load. The same holds true for the new connection to be built between RO and RS, where also low LTCs (because they are HVAC connections) hardly affect competitiveness.

For the other five non-EU investment options that depend on the installation of new expensive HVDC subsea cables, the incurred LTCs based on our CAPEX appraisal lie roughly within the following ranges:

- approx. 8 - 9 €/MWh for base load
- approx. 16 - 18 €/MWh for intermediate load
- approx. 58 - 66 €/MWh for peak load

With these values, LTCs can considerably lessen the competitiveness of non-EU projects that depend on new transmission lines, particularly for intermediate load and definitely for peak load.

Whereas all LTC values depend on base/intermediate/peak load, LCO_2s that arise on the part of the competing power plant within the EU depend on the scenario considered, with LCO_2s generally increasing from Scenario A to C. Furthermore LCO_2s can differ considerably between the types of base load power plants (cf. Annex III).

Table 86 also presents fossil fuel prices in non-EU countries in 2010. Those are derived from the same data sources as used for data gathering for EU countries (see section 5.1.2), amended with further specific information from sources for local fuel price levels. How fuel prices change up to 2050 is likewise based on the same long-term price development that underlies the EU fuel price scenarios (see also section 5.1.2).

Other country-specific model inputs for corporate taxes and labour costs are shown in Table 87. Although labour costs start at relatively low levels, a gradual rise up to 2050 to EU labour cost levels is assumed, which results in the relatively high escalation rates applied in the model for these costs.

	Corporate	Labour costs		Escalation of labour costs	
	tax	construction	operating staff	construction	operating staff
Non EU	%/a	€/pers./a	€/pers./a	%/a	%/a
country		2010	2010	real	real
AL	16%	3,000	12,444	7.8%	5.6%
DZ	25%	6,266	10,965	5.8%	5.9%
ME	9%	11,526	20,170	4.2%	4.3%
RS	10%	11,526	20,170	4.2%	4.3%
TN	30%	6,266	10,965	5.8%	5.9%
TR	20%	20,239	35,418	2.7%	2.8%

Table 87: Country-specific model inputs for non-EU countries

6.4.2 Scenario comparison

In the following, all investment prospects as calculated with the decision making model are compared between the three scenarios, as shown in Table 88 to Table 96. The nine tables break down the results by the three scenarios A, B and C as well as by the cases of base load, intermediate load and peak load. Listed for each case in the tables are the nine analysed country EU/non-EU pairs and the following belong outcomes,

- based on LEC, the least cost power plant types – for base load there is a choice between three such types to be calculated by the model
- their LEC as well as LCO_2 (EU) and LTC (non-EU)
- the discount rate, i.e. WACC, at which break-even of non-EU's LEC with EU's is attained, together with the respective power plant type with for this break-even
- whether the transmission option is based on an existing (3x) or a new (6x) transmission link.

Scenario A Base Load	EU				non-EU				break even	
linkage: existing / new	country	power plant	LEC [€/MWh$_e$]	LCO_2 [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	Lignite	71.0	26.2	TR	Lignite	47.4	0.4	Lignite	13.2%
existing	GR	Lignite	73.0	25.7	TR	Lignite	47.1	0.5	Lignite	13.8%
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	Hard Coal	82.1	20.2	TN	Hard Coal	69.3	9.4	CCGT	12.0%
new	IT	Hard Coal	82.1	20.2	ME	Hard Coal	66.8	8.6	Hard Coal	9.1%
new	IT	Hard Coal	82.1	20.2	DZ	Hard Coal	67.7	8.4	CCGT	12.8%
new	IT	Hard Coal	82.1	20.2	AL	Hard Coal	66.6	8.3	Hard Coal	9.5%
new	RO	Lignite	71.4	25.9	TR	Hard Coal	69.9	9.5	Hard Coal	5.5%
new	RO	Lignite	71.4	25.9	RS	Lignite	45.7	0.5	Lignite	13.5%

Table 88: Competing base load power plants, Scenario A

Scenario A Intermediate Load	EU				non-EU				break even	
linkage: existing / new	country	power plant	LEC [€/MWh$_e$]	LCO_2 [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	CCGT	83.1	8.7	TR	CCGT	86.5	0.7	n.a.	n.a.
existing	GR	CCGT	94.9	8.6	TR	CCGT	86.6	1.0	CCGT	13.8%
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	CCGT	100.8	8.5	TN	CCGT	86.1	17.9	CCGT	10.9%
new	IT	CCGT	100.8	8.5	ME	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	CCGT	100.8	8.5	DZ	CCGT	84.1	16.2	CCGT	11.6%
new	IT	CCGT	100.8	8.5	AL	n.a.	n.a.	n.a.	n.a.	n.a.
new	RO	CCGT	83.3	8.7	TR	CCGT	104.2	18.4	n.a.	n.a.
new	RO	CCGT	83.3	8.7	RS	CCGT	84.8	1.0	n.a.	n.a.

Table 89: Competing intermediate load power plants, Scenario A

Scenario A Peak Load	EU				non-EU				break even	
linkage: existing / new	country	power plant	LEC [€/MWh$_e$]	LCO_2 [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	GT	147.0	12.7	TR	GT	158.7	2.5	n.a.	n.a.
existing	GR	GT	170.7	12.6	TR	GT	156.7	3.7	GT	9.8%
existing	HU	GT	168.0	12.6	RS	GT	152.4	3.5	GT	10.1%
new	IT	GT	179.3	12.4	TN	GT	189.9	64.6	n.a.	n.a.
new	IT	GT	179.3	12.4	ME	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	GT	179.3	12.4	DZ	GT	182.8	58.3	n.a.	n.a.
new	IT	GT	179.3	12.4	AL	n.a.	n.a.	n.a.	n.a.	n.a.
new	RO	GT	147.8	12.6	TR	GT	222.0	66.2	n.a.	n.a.
new	RO	GT	147.8	12.6	RS	GT	153.1	3.5	n.a.	n.a.

Table 90: Competing of peak load power plants, Scenario A

Scenario B Base Load	EU				non-EU				break even	
linkage: existing / new	country	power plant	LEC [€/MWh$_e$]	LCO_2 [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	CCGT	77.7	11.9	TR	Lignite	46.6	0.4	Lignite	15.4%
existing	GR	Lignite	82.5	36.1	TR	Lignite	46.3	0.5	Lignite	16.8%
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	Hard Coal	88.6	28.4	TN	Hard Coal	67.8	9.4	CCGT	15.9%
new	IT	Hard Coal	88.6	28.4	ME	Hard Coal	65.0	8.6	Hard Coal	11.0%
new	IT	Hard Coal	88.6	28.4	DZ	Hard Coal	66.1	8.4	CCGT	16.7%
new	IT	Hard Coal	88.6	28.4	AL	Hard Coal	64.9	8.3	Hard Coal	11.5%
new	RO	CCGT	77.7	11.8	TR	Hard Coal	68.3	9.5	Hard Coal	7.7%
new	RO	CCGT	77.7	11.8	RS	Lignite	44.9	0.5	Lignite	15.6%

Table 91: Competing of base load power plants, Scenario B

Scenario B Intermediate Load	EU				non-EU				break even	
linkage: existing / new	country	power plant	LEC [€/MWh$_e$]	LCO_2 [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	CCGT	84.0	11.9	TR	CCGT	83.9	0.7	CCGT	5.2%
existing	GR	CCGT	95.4	11.7	TR	CCGT	84.0	1.0	CCGT	15.1%
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	CCGT	101.1	11.6	TN	CCGT	84.2	17.9	CCGT	11.4%
new	IT	CCGT	101.1	11.6	ME	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	CCGT	101.1	11.6	DZ	CCGT	82.2	16.2	CCGT	12.1%
new	IT	CCGT	101.1	11.6	AL	n.a.	n.a.	n.a.	n.a.	n.a.
new	RO	CCGT	84.2	11.8	TR	CCGT	101.6	18.4	n.a.	n.a.
new	RO	CCGT	84.2	11.8	RS	CCGT	82.2	1.0	CCGT	6.9%

Table 92: Competing of intermediate load power plants, Scenario B

Scenario B Peak Load	EU				non-EU				break even	
linkage: existing / new	country	power plant	LEC [€/MWh$_e$]	LCO_2 [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	GT	148.2	17.3	TR	GT	154.9	2.5	n.a.	n.a.
existing	GR	GT	171.4	17.1	TR	GT	152.9	3.7	GT	10.8%
existing	HU	GT	168.6	17.1	RS	GT	148.6	3.5	GT	11.0%
new	IT	GT	179.8	16.9	TN	GT	187.2	64.6	n.a.	n.a.
new	IT	GT	179.8	16.9	ME	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	GT	179.8	16.9	DZ	GT	180.0	58.3	n.a.	n.a.
new	IT	GT	179.8	16.9	AL	n.a.	n.a.	n.a.	n.a.	n.a.
new	RO	GT	149.1	17.2	TR	GT	218.2	66.2	n.a.	n.a.
new	RO	GT	149.1	17.2	RS	GT	149.2	3.5	n.a.	n.a.

Table 93: Competing of peak load power plants, Scenario B

Scenario C Base Load										
linkage: existing / new	EU				non-EU				break even	
	country	power plant	LEC [€/MWh$_e$]	LCO$_2$ [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	CCGT	75.3	13.2	TR	Lignite	44.6	0.4	Lignite	15.1%
existing	GR	CCGT	85.5	13.0	TR	Lignite	44.3	0.5	CCGT	20.3%
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	Hard Coal	88.6	32.3	TN	Hard Coal	63.8	9.4	CCGT	16.5%
new	IT	Hard Coal	88.6	32.3	ME	Hard Coal	60.9	8.6	Hard Coal	11.8%
new	IT	Hard Coal	88.6	32.3	DZ	Hard Coal	62.0	8.4	CCGT	17.2%
new	IT	Hard Coal	88.6	32.3	AL	Hard Coal	60.8	8.3	Hard Coal	12.3%
new	RO	CCGT	75.4	13.1	TR	Hard Coal	64.2	9.5	Hard Coal	8.1%
new	RO	CCGT	75.4	13.1	RS	Lignite	42.8	0.5	Lignite	15.3%

Table 94: Competing of base load power plants, Scenario C

Scenario C Intermediate Load											
linkage: existing / new	EU				non-EU				break even		
	country	power plant	LEC [€/MWh$_e$]	LCO$_2$ [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]	Δ LEC [€/MWh$_e$]
existing	BG	CCGT	81.6	13.2	TR	CCGT	79.7	0.7	CCGT	6.7%	1.9
existing	GR	CCGT	92.4	13.0	TR	CCGT	79.7	1.0	CCGT	14.3%	12.7
existing	HU	n.a.	n.a.	n.a.	RS	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	CCGT	97.9	12.8	TN	CCGT	81.2	17.9	CCGT	11.0%	16.7
new	IT	CCGT	97.9	12.8	ME	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	CCGT	97.9	12.8	DZ	CCGT	79.1	16.2	CCGT	11.6%	18.8
new	IT	CCGT	97.9	12.8	AL	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
new	RO	CCGT	81.8	13.1	TR	CCGT	97.4	18.4	n.a.	n.a.	-15.6
new	RO	CCGT	81.8	13.1	RS	CCGT	77.9	1.0	CCGT	7.8%	3.9

Table 95: Competing of intermediate load power plants, Scenario C

Scenario C Peak Load										
linkage: existing / new	EU				non-EU				break even	
	country	power plant	LEC [€/MWh$_e$]	LCO$_2$ [€/MWh$_e$]	country	power plant	LEC [€/MWh$_e$]	LTC [€/MWh$_e$]	power plant	WACC real [%]
existing	BG	GT	144.7	19.2	TR	GT	148.7	2.5	n.a.	n.a.
existing	GR	GT	167.0	18.9	TR	GT	146.7	3.7	GT	10.6%
existing	HU	GT	164.0	18.9	RS	GT	142.3	3.5	GT	10.8%
new	IT	GT	175.1	18.7	TN	GT	182.8	64.6	n.a.	n.a.
new	IT	GT	175.1	18.7	ME	n.a.	n.a.	n.a.	n.a.	n.a.
new	IT	GT	175.1	18.7	DZ	GT	175.5	58.3	n.a.	n.a.
new	IT	GT	175.1	18.7	AL	n.a.	n.a.	n.a.	n.a.	n.a.
new	RO	GT	145.7	19.0	TR	GT	212.1	66.2	n.a.	n.a.
new	RO	GT	145.7	19.0	RS	GT	143.0	3.5	GT	5.5%

Table 96: Competing of peak load power plants, Scenario C

Base load

Apart from restrictions on depending on whether there is sufficient transmission capacity or on fuel availability, three types of power plants are available in principle in each country for supplying base load: lignite-fired power plant, hard coal-fired power plant or natural gas-fired CCGT. Between Serbia and Hungary the available transmission capacity allows only for the export from a GT. Since also no new transmission line is planned between these countries, no base load and peak load transfer is possible for this country pair. The results reveal that without any country-specific risk premium, all baseload power plants of the non-EU countries considered would be competitive with their EU counterparts due to the avoided CO_2 cost. However, the model does not always come up with the same types of power plants outside and inside the EU.

In Scenario A, all preferred power plant options for base load in the EU countries fire coal. Without any country-specific risk premium, the associated non-EU alternatives would favour in each case the same types of power plants as in the EU country, apart from Turkey which would not be able to use lignite for supplying Romania with power. However, factoring in a risk premium up to the point where the non-EU LEC attains break-even with the EU-LEC would provide an incentive in the Maghreb countries to invest in CCGTs for base load instead, due to the relatively cheap indigenous natural gas reserves. The consequence would be, though, that there would no longer be a competitive advantage!

Due to higher ETS prices in Scenario B and particularly in Scenario C, CCGTs displace lignite power plants as the most competitive baseload power plant of choice in Romania and Bulgaria, and for Scenario C also in Greece. This is because there are no carbon costs in the non-EU countries and thus no carbon cost increase. Instead, fuel prices decreasing from Scenario A to C are the only drivers in non-EU countries for the shift away from more capital-intensive coal power plants towards CCGT.

For EU countries, not only fuel prices but also CO_2 prices account for the difference between the scenarios. The competitive advantage of non-EU investments compared to EU investments thus generally increases with a change from Scenario A to the decarbonisation scenarios B and C, at least when coal power plants in the EU countries are the best choice for comparison. This is reflected in higher break-even WACCs in Scenario B and particularly in Scenario C. The situation is different with CCGT plants that, even with the EU-ETS are generally better off in a world with global climate action (Scenario C) than with fragmented action (Scenario B), due to lower natural gas prices (cf. section 5.3).

According to the breakeven WACCs, the most promising options regarding competitiveness are found for Turkey, Serbia and the Maghreb countries, even though the latter have to bear relatively high LTCs for new transmission links. Serbia and Turkey however can benefit from lower LTCs due to existing transmission lines. The option for exporting base load power from Turkey to Romania, though, would depend on a relatively costly HVDC subsea cable, which is why this option competes poorly with the Romanian power plant investment and break-even WACCs of only between 5.5% (Scenario A) and 8.1% (Scenario C) are achieved.

Intermediate load

Accordingly for intermediate load, when transmission costs have a higher impact on levelized costs, even without a country risk premium Turkish power export to Romania is not competitive with the Romanian power plant, at least not in Scenario A and only weakly in Scenarios B and C. Due to differing natural gas prices (cf. Annex IV) Turkish export of intermediate load is competitive only in comparison to Greece, but not (Scenario A) or not very much (Scenario B and C) in comparison to Bulgaria. Among the countries with high LTC for new transmission projects only the Maghreb country projects survive in competition with EU projects. Montenegro and Albania have no natural gas access and thus neither an intermediate nor a peak load option.

Peak load

Peak load power plants that depend on new HVDC transmission line projects have, for LTC levels of roundabout 60 €/MWh$_e$ clearly no chance to compete with EU peak load power plants. In this competition, only Turkish GTs for export to Greece and Serbian GTs for export to Hungary could benefit from the carbon costs of the GT power plants in the respective EU countries, resulting in breakeven WACC levels of around 10%. In Scenario C, additionally a Serbian GT for peak load supply to Romania via a new HVAC transmission line attains competitiveness.

6.4.3 List of most promising investment prospects

The following tables show the most promising investment options in non-EU countries for base load (Table 97), intermediate load (Table 98) and peak load (Table 99). The most promising options are those with the highest calculated breakeven WACC as highlighted with the darkest green backgrounds. The colours of the WACC figures additionally indicate the type of power plant that would be the best choice in the breakeven case.

Base Load								
linkage: existing / new	EU country	non-EU country	Non-EU power plant / break even WACC for scenario					
			A		B		C	
existing	BG	TR	Lignite	13.2%	Lignite	15.4%	Lignite	15.1%
existing	GR	TR	Lignite	13.8%	Lignite	16.8%	CCGT	20.3%
existing	HU	RS	n.a.		n.a.		n.a.	
new	IT	TN	CCGT	12.0%	CCGT	15.9%	CCGT	16.5%
new	IT	ME	Hard Coal	9.1%	Hard Coal	11.0%	Hard Coal	11.8%
new	IT	DZ	CCGT	12.8%	CCGT	16.7%	CCGT	17.2%
new	IT	AL	Hard Coal	9.5%	Hard Coal	11.5%	Hard Coal	12.3%
new	RO	TR	Hard Coal	5.5%	Hard Coal	7.7%	Hard Coal	8.1%
new	RO	RS	Lignite	13.5%	Lignite	15.6%	Lignite	15.3%

Table 97: Base Load: List of investment options and their break even WACCs

The highest breakeven WACCs for base load in the non-EU countries are in the order of 13.x % in Scenario A, up to almost 17% in Scenario B and more than 20% in Scenario C (see Table 97). One frontrunner among the country-pairs is identified:

- Turkey - Greece

This option is based on the use of existing transmission lines. If the investor plans with a discount rate close to the break even WACC, then a lignite-fired power plant would be the best choice, to be exchanged only in Scenario C against a CCGT. The use of existing transmission lines without high transmission CAPEX is a prerequisite for this highlighted investment option to be so competitive.

A second group of two prospective non-EU investment alternatives is given in the Maghreb countries for power export to Italy:

- Algeria - Italy
- Tunisia - Italy

Both Maghreb options benefit from the chance to use relatively cheap indigenous natural gas resources for CCGT base load power plants. This advantage allows them to compensate the relatively high transmission costs due to the subsea cable link investments required for the connection to the Maghreb countries.

Also, thanks to low transmission costs two further investments promise almost the same high level of competitiveness, expressed by high break even WACCs in a range between 13% (Scenario A) and 15% (Scenario C):

- Turkey - Bulgaria
- Serbia - Romania

For these two options only lignite comes into consideration in all three scenarios. Export of base load power from Turkey to Greece instead of to Bulgaria would, though, be more profitable.

Intermediate Load								
linkage: existing / new	EU country	non-EU country	Non-EU power plant / break even WACC scenario					
			A		B		C	
existing	BG	TR	n.a.		CCGT	5.2%	CCGT	6.7%
existing	GR	TR	CCGT	13.8%	CCGT	15.1%	CCGT	14.3%
existing	HU	RS	n.a.		n.a.		n.a.	
new	IT	TN	CCGT	10.9%	CCGT	11.4%	CCGT	11.0%
new	IT	ME	n.a.		n.a.		n.a.	
new	IT	DZ	CCGT	11.6%	CCGT	12.1%	CCGT	11.6%
new	IT	AL	n.a.		n.a.		n.a.	
new	RO	TR	n.a.		n.a.		n.a.	
new	RO	RS	n.a.		CCGT	6.9%	CCGT	7.8%

Table 98: Intermediate Load: List of investment options and their break even WACCs

When looking at investments in intermediate load power plants (cf. Table 98), basically the same investment options remain as highlighted already for base load power plants. With break even WACCs of up to 15%, the frontrunner among the intermediate load power plants remains:

- Turkey - Greece

With lower break even WACCs also the Maghreb alternatives remain attractive:

- Algeria - Italy
- Tunisia - Italy

The options Turkey - Bulgaria and Serbia - Romania clearly lose attractiveness for intermediate load power plants and would no longer even be competitive in the reference Scenario A. Montenegro and Albania are likewise a priori discarded as intermediate and peak load options due to lack of access to natural gas supplies for CCGT or GT. For peak load GTs (see Table 99) only the use of the following existing transmission lines remains an option for:

- Turkey - Greece
- Serbia - Hungary

with breakeven WACCs fluctuating rather independently of the scenario considered at around 10%-11%. The option RO-RS in Scenario C also just attains competitiveness but at a breakeven WACC of only 5.5%, and so only slightly higher than the Serbian WACC of 4.6% that is calculated without any country-specific risk premium (cf. Annex V).

Peak Load								
linkage: existing / new	EU country	non-EU country	Non-EU power plant / break even WACC scenario					
			A		B		C	
existing	BG	TR	n.a.		n.a.		n.a.	
existing	GR	TR	GT	9.8%	GT	10.8%	GT	10.6%
existing	HU	RS	GT	10.1%	GT	11.0%	GT	10.8%
new	IT	TN	n.a.		n.a.		n.a.	
new	IT	ME	n.a.		n.a.		n.a.	
new	IT	DZ	n.a.		n.a.		n.a.	
new	IT	AL	n.a.		n.a.		n.a.	
new	RO	TR	n.a.		n.a.		n.a.	
new	RO	RS	n.a.		n.a.		GT	5.5%

Table 99: Peak Load: List of investment options and their breakeven WACCs

For peak load power plants, the gains that a power plant investment in a non-EU country can attain due to the advantage of absence of carbon costs is no longer significantly dependent on the scenario considered, for which there are two reasons:

1. LCO_2 expenditure accounts for only a small fraction of overall LECs for peak load.
2. For gas turbines, fuel prices play a preeminent role but outweigh ETS prices for all three scenarios.

For intermediate load and particularly for base load, however, these aspects dwindle in significance and carbon costs enhance the competitiveness of the non-EU power plants. That’s why for base load the observed breakeven WACCs are generally higher in Scenario C than in Scenario A.

Generally, base load power plants provide the most attractive investment options, for two reasons:

1. Levelized transmission costs are lowest at highest annual full load hours.
2. Base load is the segment that is most attractive for CO2 intensive coal power plants, which in particular allows non-EU investments to prove their superiority regarding carbon costs.

The aforementioned six highlighted country pairs and the relative competitiveness averaged over all three scenarios of the non-EU versus the EU power plant investment options are illustrated in Figure 93 for the three different market segments base/intermediate/peak load.

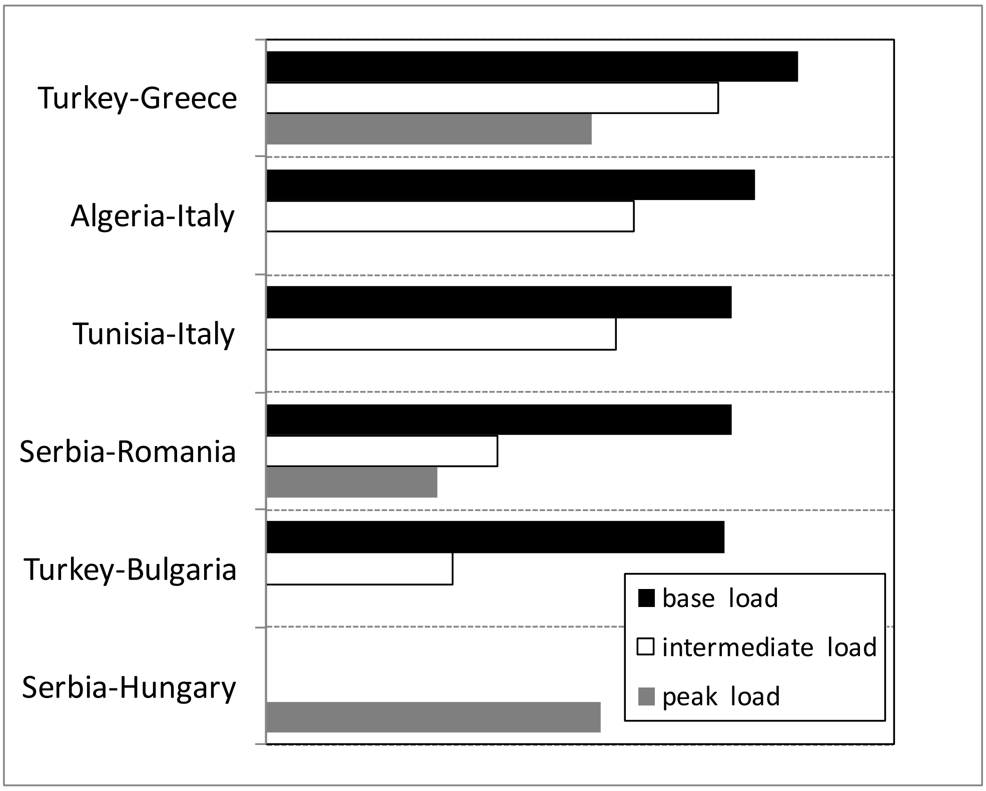


Figure 93: Relative competitiveness of most relevant investment options

Turkey, Algeria, Tunisia and Serbia are the most promising non-EU countries for new power plant investments that would profitably export power, preferably base load, to EU countries. Greece and Italy and, with minor importance, also Bulgaria, Romania and Hungary may import such electricity.

7. Renewable Energy and CDM Projects

In the previous chapters of this study, investment in power plants fired with fossil energies inside and outside the EU have been analysed with the main objective of assessing the economic and microeconomic impacts of full auctioning of emission rights on investment decisions by potential investors. The objective of this part of the study is to analyse the possibility of investing in electricity generation from renewable energy within the framework of CDM in non-EU countries and whether such CDM projects could lead to double-counting and could thus undermine the EU ETS.

7.1 Differences between Fossil and Renewable Energy Projects

Before starting with the investigation of projects within the framework of CDM, some important differences between power generation from fossil energy versus renewable energy in general shall be outlined and discussed.

The main difference is that there are *no CO_2 emissions* from renewable energy, so there is no advantage of avoided CO_2 cost as is the case for fossil fired power generation. Under this aspect, there is no inducement for investing outside the EU for electricity import into the EU.

Electricity from renewable energy is promoted in the EU. The Renewable Energy Directive [2009/28/EC] establishes a common framework for production and promotion of energy from renewable sources. Some member states oblige grid operators to take off renewable electricity and remunerate this with a relatively attractive feed-in tariff. This obligation does not apply for electricity produced outside the EU.

An important aspect concerns *the location* of the power plants. For fossil fired power plants, the location is not a decisive factor for the economic viability of a project. In practice, power plants are built where electricity is needed, so the main criterion for site selection is closeness to major centres of consumption as well as power grid accessibility. Climatic conditions have also some effect because the energy efficiency of power plants is lower in hot climates but, as mentioned above, there is no free choice of the locations as power generation is to be placed close to the demand centres.

In contrast, location is the most decisive criterion for site selection for renewable energy projects. Apart from availability of grid access, renewable energy projects are only viable in locations offering favourable *natural resources*, like solar radiation and wind. In this respect, we have first to distinguish between wind and solar power.

Wind resources provide favourable conditions for *wind power* in the EU, especially offshore, and investors will scarcely find better locations outside the EU. *Solar power* projects, though, with concentrated solar power technologies are an attractive option in North Africa where the solar irradiation provides excellent conditions. Only few locations with sufficient irradiation are available in the southern Mediterranean EU countries. Hence, an attractive option for solar power generation on a large scale for import into the EU is solar power plants in North Africa.

A major drawback of power from renewable energy is its intermittent nature depending on time of the day and the current availability of the natural resource. In this respect, too, a distinction has to be made between wind and solar energy. While wind power may be available day and night depending on wind intensity, solar irradiation is available only during daytime with hours of sufficient irradiation. However, there are state-of-the art thermal storage technologies for solar energy while storage is technically much more demanding and cost intensive for wind power, mainly because of its much higher production rate.

Under the aspect of security of supply, electricity from renewable energy requires sufficient backup capacities from fossil power plants. As a worst case we can assume that a duplication of capacities is required to ensure power supply at <u>any time</u>. Under this assumption, the following Table 100 is developed that provides a rough assessment of the cost implications for selected options with combinations of renewable and fossil power.

Type of plant	Symbol	Rated output MW	Life time a	CAPEX $€/kW_{gross}$	Discount rate real %/a	Fuel cost $€/MWh_t$	EOH h/a	Capacity cost €/kW x a	LEC total €/MWh	LEC marginal €/MWh
Single power plant units										
Steam power plant, hard coal	SPP_coal	800	35	1,900	5.5%	13.00	7,500	169	56.49	30.01
Combine cycle gas turbine	CCGT_NG	800	25	660	5.5%	25.00	7,500	60	56.69	48.71
Combine cycle gas turbine	CCGT_NG	800	25	660	5.5%	30.00	4,500	60	71.05	57.75
Gas turbine	SCGT_NG	150	25	500	5.5%	35.00	1,250	43	131.18	97.11
Wind farm on-shore	W_Land	25	25	2,000	5.5%	-	2,200	170	77.44	-
Wind farm off-shore *)	W_Sea	250	25	4,500	5.5%	-	4,500	406	90.23	-
CSP_ parabolic trough_8 h TES **)	CSP	150	25	4,500	5.5%	-	4,500	457	102.51	1.00
PV ***)	PV	50	20	1,000	5.5%	-	1,500	89	59.58	-
Plant combinations for base load										
Wind on-shore + CCGT	W_Land	25	25	2,000	5.5%	-	2,200	170	65.12	34.42
	CCGT		25	660	5.5%	25.00	5,300	60		
Wind off-shore + CCGT	W_Sea_CCGT	250	25	4,500	5.5%	-	4,500	406	86.60	24.48
	CCGT		25	660	5.5%	30.00	3,000	60		
Plant combinations for intermediate load										
Wind on-shore + CCGT	W_Land	25	25	2,000	5.5%	-	2,200	170	80.68	29.52
	CCGT		25	660	5.5%	30.00	2,300	60		
Wind on-shore + SCGT	W_Land	25	25	2,000	5.5%	-	2,200	170	96.19	48.86
	SSCT		25	500	5.5%	35.00	2,300	43		
PV + SCGT	PV_SCGT	50	20	1,000	5.5%	-	1,500	89	94.06	64.74
	SSGT		20	500	5.5%	35.00	3,000	43		
*) site North Sea	**) site South Spain		***) South Germany							

Table 100: Cost implications renewable power and combinations of renewable and fossil power

Another aspect that is to be highlighted is the low capacity utilization factor of power supply from renewable energy that might also be a major barrier for import of electricity from renewable energy into the EU. As already shown in the previous chapters, transmission costs become higher with lower capacity factors.

In summary we can conclude that export of electricity from renewable energy from power plants in countries adjacent to the EU into the EU is currently not an attractive option for investors. It could become attractive for large-scale solar energy projects that can exploit economies of scale for both power generation and power transmission. In this respect, the planned **Desertec** project can be mentioned as a viable alternative for the medium term.

7.2 Increased CO_2 emissions from CDM projects?

This section describes to what extent renewable energy power plants erected for importing electricity into the European Union may qualify for Certified Emission Reductions (CERs) from CDM projects (section 7.2.2) and under which conditions this may lead to double counting (section 7.2.3). This is compared in section 7.2.4 with the carbon leakage effect caused by importing fossil fuel power into the EU. First, though, the CDM regulations in general are described in the next section.

7.2.1 CDM regulations

CDM projects are possible in non-Annex-I countries of the United Nations Framework Convention on Climate Change (UNFCCC), i.e. countries with no binding emission reduction targets. From the group of countries investigated here these are:

- Algeria
- Bosnia and Herzegovina
- Egypt
- Libya
- The Former Yugoslav Republic of Macedonia
- Moldova
- Montenegro
- Morocco
- Serbia
- Tunisia

Directive 2004/101/EC (the ‘Linking Directive’) allows participants of the EU ETS to use credits generated from the Kyoto Protocol’s project-based mechanisms CDM (Clean Development Mechanism) and JI (Joint Implementation) for fulfilling their obligations under the trading scheme.

CDM and JI have in common that they enable investments in emission reduction projects (e.g. renewable energy, energy efficiency measures) to be made abroad in countries that are also party to the Kyoto Protocol. In the case of JI, these investments are made in countries which in turn have an emission reduction obligation. In the case of the CDM, these projects are implemented in countries with no obligation (developing countries).

For every ton of CO_2 that is reduced by a CDM or JI project, a carbon certificate is issued that can be used in the EU ETS. In the case of CDM, these credits are called Certified Emission Reductions (CERs). In JI projects, Emission Reduction Units (ERUs) are generated.

It is important to understand that the CDM does not seek to reduce greenhouse gas emissions beyond the binding emission reduction targets under the Kyoto protocol. Rather the CDM is intended to provide an incentive for emission reduction measures outside Annex-I countries, i.e. countries with binding emission reduction targets, through investments by entities from Annex-I countries. It is expected that in this way the total costs of the targeted emission reduction are reduced because the emission reduction potential in non-Annex I countries is expected to be exploitable at lower costs than in Annex-I countries.

These CERs can be traded in the European Emissions Trading Scheme (EU ETS), thus enlarging the volume of available emission allowances. The use of CERs and ERUs in the second trading period is allowed and remaining unused credits from this period can be transferred for use in the third trading period. Also credits from pre-2012 registered CDM projects that will be generated after 2012 can be used. In any case, the use of CERs is restricted to 50% of the reduction effort.

But for new projects, at present (October 2012) the possibility of trading in CERs in the EU ETS is restricted. CERs will only be eligible for the EU ETS from emission reduction projects registered by 31 December 2012. Thus new power plants seeking registration after this date will not be eligible for the EU ETS. The validation and registration process usually takes between six months and two years. An emission reduction project, i.e. a renewable energy power plant, needs to be sufficiently advanced prior to seeking registration with the UNFCCC. Thus, we expect a rather limited number of renewable energy power plants that have not yet been realised to have been registered by 31 December 2012.

Country	Registered		Application in process	
	No. of projects	tCO_2/a	No. of Projects	tCO_2/a
Algeria	-	-	-	-
Bosnia and Herzegovina	-	-	-	-
Egypt	1	170,364	-	-
Libya	-	-	-	-
The Former Yugoslav Republic of Macedonia	-	-	-	-
Republic of Moldova	-	-	-	-
Montenegro	-	-	-	-
Morocco	3	733,358	-	-
Serbia	3	1,291,830	-	-
Tunisia	-	-	-	-

Table 101: Number of projects and certified emission reductions of renewable energy power plants registered or in process between 1 January 2011 and 31 August 2012

Table 101 provides an indication by depicting renewable energy power plants that have been registered or are seeking registration between 1 January 2011 and 31 August 2012. No projects are currently in the process of application in the countries of interest. In this regard, a certain loophole exists with the Programme of Activities (PoA) under the UNFCCC which bundles several individual power plants to a CDM project: As long as a PoA is registered before 31 December 2012, the CERs generated under this PoA will be eligible for the EU ETS even if a specific renewable energy power plant is incorporated into the PoA after 31 December 2012.

For the third trading period, though, the ETS Directive restricts the use of CERS and ERUs from <u>new</u> CDM and JI projects that have been registered post-2012 unless:

- a satisfactory international agreement on climate change is approved by the Community
  or, in the absence of such an agreement,
- the EU enters into a bilateral agreement with a country.

An exception is the acceptance of credits from new projects implemented in Least Developed Countries (LDCs) after 2012. They can be used in the third trading period even in the absence of such agreements as stated above. But among the non-EU countries adjacent to the EU there are no LDCs. The restricted access of CERs into the EU ETS, though, only holds as long as no international legally binding emissions reduction target as a follow-up to the Kyoto protocol has been established.

7.2.2 Qualification of REN projects for CDM

Investments in electricity generation capacity from renewable energy under Clean Development Mechanism (CDM) projects in non-EU countries represent a special case. Beyond the pure generation of electricity, renewable energy power plants may potentially also generate CERs under the umbrella of the UNFCCC in the above listed Annex I non-EU countries.

For grid-connected electricity generation from renewable energy, the calculation of CERs is stipulated in the Approved Consolidated Baseline and Monitoring Methodology [ACM0002]. The baseline for a CDM project activity (i.e. the renewable energy power plant in our case) is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity [3/CMP]. In other words, a baseline for a CDM project activity is a hypothetical reference case, representing the volume of greenhouse gases that would have been emitted if the project were not implemented. Therefore, the baseline can be used to determine:

1. whether a CDM project activity is additional
   and
2. the volume of additional greenhouse gas emission reductions achieved by a project activity.

If the CDM project activity (i.e. the renewable energy power plant in our case) is deemed not to be ‘additional’, the project does not qualify for the CDM and thus does not generate CERs. The analysis of additionality is highly project specific and so this cannot be determined generically here for the case of renewable energy power plants importing electricity into the EU. In contrast, the determination of the baseline for the purpose of calculating CERs can be achieved on a more generic level.

[ACM0002] stipulates that, if the project activity is the installation of a new grid-connected renewable power plant/unit, the baseline scenario is the following: electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the “Tool to calculate the emission factor for an electricity system” [UN_Tool]. This tool defines the Project Electricity System (PES) as the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity (e.g. the renewable energy power plant location) and that can be dispatched without significant transmission constraints. This tool offers two criteria for defining transmission constraints:

- In the case of electricity systems with spot markets for electricity: there are differences in electricity prices (excluding transmission and distribution costs) of more than 5% between the systems during 60% or more of the hours of the year.

- The transmission line is operated at 90% or more of its rated capacity during 90% or more of the hours of the year.

The tool further defines a Connected Electricity System (CES) which is an electricity system that is connected by transmission lines to the PES. According to this definition, system boundaries are defined in such a way that power plants within the CES can be dispatched without significant transmission constraints but transmission to the PES has significant transmission constraints. Electricity transfers from the PES to CESs are defined as electricity exports. Electricity exports should not be subtracted from electricity generation data used for calculating and monitoring the electricity emission factors. If a CES is located partially or totally in Annex I countries, like in the EU, then the emission factor of that CES should be considered zero.

Thus how will the emission reduction of a renewable energy power plant situated in a non-Annex I country and dedicated for export into the European Union be assessed under the CDM? First it depends on the actual physical connection of the renewable energy power plant (REN PP). If the REN PP is feeding into an HV line dedicated for the transfer of electricity into the European Union, then the national grid of the host country is not affected. No emissions are avoided in a non-Annex I country with the outcome that **no** CERs are issued for the REN power plant.

A similar case arises if the REN power plant feeds into the national grid and the national grid is connected physically to the European Union *and* a power purchase agreement of the REN PP with a purchaser in the European Union is in place. Then the REN PP would be deemed to be not substituting power supply in the non-Annex I country, so it would not qualify under the CDM.

In both cases, UNFCCC regulations provide sufficient safeguards to avoid double counting. A different case arises if the REN PP feeds into the national grid and the national grid is connected physically to the European Union *and no* power purchase agreement of the REN PP with a purchaser in the European Union is in place. Then the REN power plant would be eligible under the CDM. CERs in the amount of avoided national emissions would be issued.

> In summary: only in those cases
>
> - where the REN power plant is directly and exclusively connected to a direct power line into the European electricity system
>
> or
>
> - when the power purchase agreement of the REN power plant is made directly with a purchaser in the European electricity system,
>
> do UNFCCC regulations prohibit the approval of CERs under the Clean Development Mechanism.

7.2.3 Double counting effect from CDM projects

REN PP projects situated in non-Annex I countries and dedicated for electricity import into the European Union may unduly benefit from achieving CERs although the electricity generation does not avoid any emissions in the host country. As assessed from the UNFCCC regulations, this could become the case for all REN PPs that are not directly and exclusively connected to a direct power line into the EU or that have a power purchase agreement directly with a purchaser in the EU. However, if the electricity generated from a CDM project is to be supplied to the EU, this increases overall global emissions. In the following, the mechanism/reasoning behind this is illustrated.

In the above case of interest, the following effects could accrue to the EU ETS:

a) CERs issued from such projects could be used by installations included in the EU ETS. Thus within the EU it would allow for overall higher CO_2 emissions on top of the ETS cap, justified as compliance for the emission reductions achieved outside the EU.

   Example: *Assume the number of allowances that have to be acquired with costs by all ETS market participants is 1000 EUAs. Now a renewable CDM project is to be realized outside the EU which grants CERs that are equivalent to 3 EUAs. The 3 EUAs can be used additionally in the ETS market, expanding the* CO_2 *emissions that are effectively allowed to an equivalent of 1003 EUAs.*

b) However, to the extent this electricity from CDM projects is imported into the EU, the associated emission reductions are not actually achieved outside the EU. Instead the emission reductions are effective within the ETS framework. In practice, the reductions allow higher emissions from other sources within the ETS cap. (This to be compared with the effect from CERs explained in a), which allows higher emissions on top of the ETS cap.)

   Example: *Due to the import of the renewable electricity from the CDM project, the electricity demand of the EU is supplied at a level of* CO_2 *emissions that is equivalently lowered by 3 EUAs. The overall ETS cap is not changed by this, but the demand for allowances is decreased, resulting in a lower allowances price. Emissions to the equivalent of 3 EUAs can instead be emitted somewhere else under the EU ETS, for instance by industrial applications.*

So, combining a) and b), the emission reductions from the CDM project outside the EU allow duplicated compensation under the ETS instead of only once (so-called ‘double counting’). The upshot is that this effectively causes higher total emission volumes over all involved countries.

Example: Regard the examples of a) and b) from above. Since electricity from the renewable CDM project is transmitted to the EU, emissions in the non-EU country concerned are not changed. Emissions in the EU, though, are increased by 3 units. Thus in total an increase of CO_2 emissions equivalent to 3 EUAs is brought about.

In such a scenario, the integrity of the EU ETS is undermined under the aspects of environmental protection (1003 EUAs equivalent CO_2 emissions instead of 1000 EUAs) and economics (downward pressure on allowance price conveys wrong or distorted economic signals to installations).

It must be emphasized here that this increase of emissions is not caused by renewable CDM projects in general. Instead, only if the generated electricity from the REN PP is ***imported into the EU*** and if it is ***granted CERs***, then this situation causes double counting of emission reductions. This is because issuance of CERs is authorised on the assumption that the renewable electricity produced is displacing more CO_2 intensive electricity somewhere else. However, if this electricity is exported to and consumed in the EU, it cannot be used to displace more CO_2 intensive electricity consumption in the country generating this renewable electricity. As a consequence, the CERs are used to justify the emission of more greenhouse gases in the EU without offsetting emissions elsewhere.

Without electricity imports no double counting and no overall increase of emissions results from CDM projects:

Example: Regard again the examples of a) and b) from above but now assume that, unlike b), the electricity is not imported into the EU. Again the overall ETS would be increased up to 1003 EUAs due to CERs from the CDM project (compare with a)). However the CDM project would, in the non-EU country, effectively reduce 3 units of carbon emissions for which it was granted. The emission reduction of 3 EUAs outside the EU compensates for the 3 EUAs more within the EU. Effectively, in total no more emissions have been caused by the project than without it.

It is only in the case of imports into the EU that electricity from REN CDM projects cannot displace CO_2 intensive electricity consumption in the generating non-EU country and would thus be endowed with unjustified CERs that come on top of the ETS emission cap and would bring about globally increased emissions.

7.2.4 Electricity import into the EU and its impact on overall CO_2 emissions

The example given for increased overall CO_2 emissions from a renewable CDM project will now be compared with the carbon leakage effect for the case where instead a **fossil fuel** fired power plant in the non-EU country is transferring its generated electricity into the EU.

Example: *Assume again that the number of allowances that have to be acquired and paid for by all ETS market participants is 1000 EUAs. Now assume that the EU imports electricity from a fossil fuel fired power plant outside the EU that causes CO_2 emissions equivalent to 3 EUAs. The imported electricity does not impact the overall ETS cap. Emissions from electricity generation within the EU can instead be emitted somewhere else within the EU ETS, for instance by industrial applications. However in the non-EU country CO_2 emissions are increased equivalent to 3 EUAs without having any further impact on the electricity supply and the CO_2 emissions in this country. Thus in total a carbon leakage effect equivalent to 3 EUAs is caused.*

From an environmental point of view, the effect would be the same as in the case of imported electricity from the CDM project. The environmental and economic integrity of the EU ETS is again undermined. However, there are some general differences between the carbon leakage effect from fossil fuel fired power plants and the double counting effect from renewable CDM projects:

- The amount of carbon leakage in terms of additional CO_2 emissions depends for the case of the fossil power import on the **CO_2-efficiency of the fossil fuel fired power plant** per generated unit of electricity. In the example of the fossil fuel power import above, a non-CO_2-efficient power plant may emit the equivalent of 4 EUAs instead of only 3 EUAs in order to supply the same amount of electricity to the EU. This would increase the carbon leakage effect accordingly.
  For the CDM project, however, the amount of increased emissions depends on the credited CERs in terms of EUA equivalents. This depends for a renewable power plant project on the applied baseline scenario (see section 7.2.2). According to the conclusions from 7.2.2, the only electricity generated by CDM projects that is eligible for CERs is that which is not imported via a direct and exclusively connected power line into the EU and that is not sold via a power purchase agreement to a purchaser in the EU. In the remaining cases, usually the **national CO_2 emission factor** of the respective non-EU country will be the starting point for the baseline calculation and for the number of granted CERs, because in the CDM assessment of the project the electricity export to the EU will not be detectable.

- Whereas for fossil fuel fired power plants the **inducement of the ETS** for carbon leakage results from the carbon costs for fossil fuel fired power plants, for renewable CDM projects the inducement consists of the reimbursement of the granted CERs.

- Another, albeit less important, difference between the two scenarios is that the emissions on top of the EU ETS cap arise at different **locations**:
  - outside the EU, in the case of fossil fuel power import into the EU, and
  - inside the EU in the case of import of CDM power import into the EU.

- Because of the limited number of already established and ongoing REN PP CDM project activities in countries neighbouring the EU (cf. Table 101), the threat of a substantial overall increase of CO_2 emissions from CDM projects stems more from **new CDM projects** to be planned rather than from already established CDM projects. However, when considering fossil fuel fired power plants also the huge amount of **already existing power plant capacities** could potentially contribute to carbon leakage if generated electricity is transmitted to the EU.

In the context of the latter aspect it may be emphasized, that **each electricity import into the EU** - also from existing power plants - cannot contribute to lessening CO_2 emissions within the EU due to the fixed ETS cap. But instead electricity import into the EU from existing power plants may be perceived as carbon leakage in the special case of if the electricity could be used instead within the non-EU country to avoid other CO_2 emissions from power generation. This may even concern the import of CO_2-free electricity into the EU. An example that may be given is Ukraine, which is planning to export CO_2-free electricity from its existing nuclear power plants to the EU and to compensate these power exports with increased electricity generation from its aging fossil fuel power plant fleet.

Similarly, **electricity exports from the EU** to neighbouring countries would cause in reverse a 'negative carbon leakage effect', i.e. would improve the global CO_2 emission balance. Power generation in the importing non-EU country would then be avoided and would usually also give rise to CO_2 emission reductions in the country concerned. Within the EU, however, CO_2 emissions would remain the same due to the fixed emission cap. Thus in total (i.e. EU plus non-EU), CO_2 emissions would be reduced.

8. List and Scale of Known Investments

Set out in the following are ongoing, planned and potential investments in new electricity generation capacity in the non-EU countries considered whose purpose is to supply electricity to the EU. The projects as listed in Table 102 were identified based on our own research and publicly available information on the web.

Country	Export to	Power plant fuel	Capacity…	…for export
Albania	Italy	Hard coal	1,600 MW	1,360 MW
Belarus	Poland	Hard coal	920 MW	600(?)-920 MW
Tunisia	Italy	Natural gas, CCGT	1,200 MW	800 MW

Table 102: Ongoing, planned and potential investments in new power plants for electricity import into the EU

8.1 Coal-fired Power Plant in Albania to Supply Italy with Electricity

The Italian utility Enel plans to build a coal-fired thermal power plant in Porto Romano near the City of Durres in Albania. Enel already set up a joint venture with Albanian industrial firms in 2009 [REUT]. According to [CEE 2010], the planned two units of 800 MW each are to be fired by imported hard coal and are dedicated to export about 85% of the generated electricity via HVDC undersea cables to Italy. If the power plant were to be erected in Italy instead, Enel would have to buy CO_2 emission rights.

Environmental associations have protested against the Albanian government as well as the Italian project developer and complain about unanswered questions concerning the impacts and aims of the power plant project. As a consequence of the project, total Albanian CO_2 emissions would increase approximately by a factor of 2.5 from the current level, according to [CEE 2010]. Since Albania's present overall CO_2 emissions are at about the same level as in 1990, any future CO_2 reduction strategies of Albania would be seriously undermined by the new project. This raises also concerns that the project could seriously hamper Albania's ambitions to join the EU. Also the competitiveness of the economy could be impaired due to the high CO_2 emission costs that would result from participation in the ETS that would be a condition for accession to the European Union.

The Albanian government and Enel argue that energy security would be improved and have announced cost-price electricity supply for Albania [CEE 2010]. An environmental impact study for this undertaking, though, is regarded as inadequate by its opponents because of deficiencies in the analyses of emissions, socio-economic factors as well as environmental management and monitoring plans [CEE 2009]. And from the viewpoint of security of supply, [CEE 2010] sees no need for such a large scale power plant in Albania.

According to our estimation (cf. Table 86), the CAPEX for the transmission project is in the order of €1 billion .

8.2 Hard Coal PP in Belarus for Exporting Electricity to Poland

The Polish investment company Kulczyk Holding and the Belarusian state production association Belenergo signed a cooperation agreement in 2010 following a letter of intent from 2008 to build a 920 MW coal-fired thermal power plant in Belarus [BNAA]. This is to be located in the Grodno region at the city of Zelva near the Polish border [OOI]. 10% of the designated hard coal fuel is to be substituted by Belarusian peat in line with a state program for deploying the country's own energy resources in the national fuel balance. The remainder is to be imported by train from Russia, Ukraine and Poland, here especially from the Bogdanka Colliery [GDP, BNAA].

According to the offer from the Ministry of Energy of the Republic of Belarus, the investment is to be realised under a private and public partnership as a BOT or BOOT scheme that proposes construction of the power plant by the investor and its operation over a specified period to earn a profit and amortize the investment [OOI]. Furthermore, the Republic of Belarus guarantees to the developer that it will purchase all the generated electricity, assuming 5,500 full-load operating hours. Additionally, it declares to build the needed power lines to connect the plant to the Belarusian grid at its own expense [OOI]. Belarus had been looking for an investor to build a coal-burning condensing plant in Zelva. Subsequently Belarus and the Polish Kulczyk Holding made a deal between Belarusian Grodnoenergo and the Polish holding company to build a 920 MW coal-fired plant in Belarus' Zelva, and a 400 kV power line with a DC link to connect the Belarusian Ros Substation with the Polish power grid [EXBY].

The Polish and Belarusian power grids are in asynchronous operation. Power will be transmitted between the cities of Ros (BY) and Narev (PL) via a 400 kV line and a back-to-back DC link on the Belarusian side to export the generated electricity to the neighbouring EU country, Poland [BNAA, BAKU, CICS]. For this purpose, the intention is to build the new line along the existing corridor of a retired 220 kV transmission line between Bialystok and Ros over a distance of 120 km – 75 km on Polish and 45 km on Belarusian territory [PSEDP 2010]. The mooted capacity of the new connection will be 600–1,000 MW. Realisation of the construction is excluded before the year 2015 [PSEDP 2012, B_NPP, PSE, GDP]. Nevertheless, the Polish TSO quotes a three-year implementation time after authorisation [PSE].

Regarding financial aspects, the development strategy results in estimated project costs of €1.5 billion to be funded by foreign loans and Belarusian funds guaranteed by the Government of Belarus [GDP].

In May 2011, the project was put on hold because the Polish and Belarusian investors failed to reach a consensus on its funding [EXBY]. The Polish party under Jan Kulczyk suspended the deal because of increasing difficulties over financing conditions. According to Kulczyk, a project of this scale requires bank interests and 'given the current climate surrounding [in] Belarus it would be hard to finance such a project.' At this point of time, Belarus's foreign-currency reserves had reached a low level and the country's current-account deficit increased up to 16% of its gross domestic product [BL, BAKU, EXBY].

In May 2012, Prime-TASS reported that a further decision to build the Zelva power plant depends on the development of global coal and gas prices [EXBY]. Prime-TASS referred to a draft programme for Belarus' industrial development that spans a period up to 2020.

8.3 Italian Tunisian Power Plant Project ELMED

In August 2008, the Italian and Tunisian Ministers for Economic Development signed an intergovernmental agreement for the energy sector on a joint electricity generation and transmission project [TER 2009]. The Italian grid and transmission system operator Terna and the Tunisian state-owned organisation responsible for electricity generation, transmission and distribution, the Société Tunisienne de l'Électricité et du Gaz (STEG), were commissioned to develop a power plant in Tunisia and to build a related transmission system between Italy and Tunisia.

For this purpose, Terna and STEG entered into a partnership agreement in March 2009 to set up the Tunisian-Italian joint venture ELMED to realise the electricity generation and transmission project. A prequalification phase for potential operators of the transmission line started in 2010 [FIPA].

The connection is to be an HVDC subsea cable with a final transmission capacity of 1000 MW. Starting in the city of Al-Haouaria, crossing the Mediterranean Sea and arriving at the Sicilian city of Partanna results in a total distance of about 200 km for the link [GENI]. The interconnector is planned for development in two stages: 400-500 MW in the first phase and 500 MW in the second phase. For the second phase, reinforcement of the Sicilian grid is a prerequisite [MEDRING_UP1]. The final configuration will be a bipole at ± 400 kV DC [MEDRING_UP1] for bidirectional connection of the Tunisian grid to Western Europe [GENI].

The scheme includes a 1200 MW thermal power plant in Al Haouaria (Tunisia) [TER 2010] that will be coal- or gas-fired [MEDRING_UP1]. According to [FIPA], it will be a CCGT plant and will include a renewable energy component of at least 100 MW.

The interconnector will be operated in the form of a "merchant" interconnection with 80% of capacity exempted from TPA and reserved for the investor in the new power plant. This value is compliant with the Italian Ministerial Decree on Merchant Lines issued in October 2005 [MEDRING_UP1]. The interconnector is expected to enter into operation in 2016 [MEDRING_UP1]. In [TYNDP 2012], the ELMED transmission line is quoted as being under the "design and permitting" process and described as "delayed due to longer than expected authorisation procedures".

This means that 800 MW of the power plant capacity is dedicated for electricity export to Italy, with 400 MW for STEG to supply the Tunisian market [GENI].
The balance of 200 MW transmission capacity is open for third party access under the rules and procedures established by the Italian and Tunisian governments [GENI]. This capacity may eventually be used for trading "green energy" between the Maghreb and Italy on the basis of Art. 9 of the EC Directive [2009/28/EC] on "the promotion of the use of energy from renewable sources" [MEDRING_UP1], and the power plant will not be commissioned before 2017 [PEI]. The IPP should be developed under a build-own-operate basis with a 20–30 years concession. [PEI]

According to our estimation (cf. Table 86), the transmission CAPEX for the project is in the same range of about €1 billion, like for the Italy-Albania project. But due to low-cost natural gas in Tunisia, the competitive advantage enjoyed by this project is assessed in the model to be higher than for power transmission from Albania.

8.4 Conclusions

The presented investment projects underline the prominent role that Italy plays as a potential importer of electricity from new power plants outside the EU that may be installed with the aim of supplying electricity into the EU. The example of the planned power plant investment in Belarus shows how important the political situation as well as a synchronized power connection to the EU network can be.

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10. Glossary

AAC	Already Allocated Capacity
AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
ARA	Amsterdam, Rotterdam, Antwerp
ATC	Available Transfer Capacity
B2B	Back-to-Back
BAT	Best Available Technologies
BEMIP	Baltic Energy Market Interconnection Plan
BOT	Build Operate Transfer
BOOT	Build Own Operate Transfer
BREF	BAT Reference Documents
BRELL	BRELL synchronous operation zone (Belarus-Russia-Kaliningrad-Estonia-Latvia-Lithuania)
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Condenser cooling system
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CES	Connected Electricity System
CIF	incl. Cost Insurance Freight
CIS	Commonwealth of Independent States
CM	Combined margin
CO_2	Carbon dioxide
COTC	Commission on Operative-Technological Coordination of parallel operation of the power systems of the CIS and Baltic countries
CREG	Commission de régulation de l’électricité et du gaz
DC	Direct Current
EC	European Commission
EEA	European Economic Area
EHV	Extra High Voltage level
ELVs	Emission Limit Values
ENTSO	European Network of Transmission System Operators
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-E RG CE	ENTSO-E Regional Group Central Europe
EOH	Equivalent Operation Hours
EPC	Engineering, Procurement, Construction
EPC CIS	Electric Power Council of the CIS
ERUs	Emission Reduction Units from Joint Implementation (JI) projects
ETS	Emission Trading Scheme
EUA	EU Allowances
GHG	Greenhouse gases
GT	Open cycle gas turbine
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IE	Industrial Emissions
IED	Industrial Emissions Directive
IPPC	Integrated Pollution Prevention and Control
IPS	Interconnected Power Systems

ISO	Independent System Operator
ITO	Independent Transmission System Operator
JI	Joint Implementation
LCC	Line Commutated Converter
LCO_2	Levelized CO_2 cost of electricity
LCP	Large Combustion Plant
LDC	Least Developed Countries
LEC	Levelized electricity cost
LNG	Liquefied natural gas
LTC	Levelized transmission cost of electricity
MEDRING	Mediterranean Energy Ring
MS	Member States
NAP	National allocation plans
NCV	Net calorific value
NO_x	Oxides of nitrogen
NPC	Net present cost
NTC	Net transfer capacity
OHL	Overhead line
OPEX	Operational expenditures
OTC	Over-The-Counter
OU	Ownership Unbundling
O&M	Operation and maintenance
PES	Project Electricity System
PoA	Programme of Activities
PV	Present value
REE	Red Eléctrica de España
REN PP	Renewable Energy Power Plant
RG CE	Regional Group Continental Europe
ROE	Return on equity
ROI	Return on investment
SC	Supercritical steam conditions
SO_2	Sulphur dioxide
TNP	Transitional National Plan
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UCTE	Union for the Coordination of Transmission of Electricity
UNFCCC	United Nations Framework Convention on Climate Change
UPS	Unified Power Systems
USC	Ultra-super critical steam conditions
VSC	Voltage Source Converter
WACC	Weighted average costs of capital
$WACC_r$	Weighted average costs of capital, real
$WACC_n$	Weighted average costs of capital, nominal
XLPE	Cross Linked Polyethylene

11. Annex

11.1 Annex I: Levelized CO_2 Prices

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / t CO_2	28.03	28.03	23.93	23.93	23.93
EE - Estonia	€ / t CO_2	N.A.	27.41	23.58	23.58	23.58
ES - Espania	€ / t CO_2	N.A.	26.78	23.22	23.22	23.22
FI - Finland	€ / t CO_2	N.A.	27.18	23.45	23.45	23.45
GR - Greece	€ / t CO_2	27.47	27.47	23.61	23.61	23.61
HU - Hungary	€ / t CO_2	27.53	27.53	23.65	23.65	23.65
IT - Italy	€ / t CO_2	N.A.	26.97	23.32	23.32	23.32
LT - Lithuania	€ / t CO_2	N.A.	27.76	23.78	23.78	23.78
LV - Latvia	€ / t CO_2	N.A.	27.76	23.78	23.78	23.78
PL - Poland	€ / t CO_2	27.53	27.53	23.65	23.65	23.65
RO - Romania	€ / t CO_2	27.71	27.71	23.75	23.75	23.75
SI - Slovenia	€ / t CO_2	27.47	27.47	23.61	23.61	23.61
SK - Slovakia	€ / t CO_2	27.53	27.53	23.65	23.65	23.65
Average	€ / t CO_2	27.61	27.47	23.61	23.61	23.61

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / t CO_2	39.38	39.38	32.53	32.53	32.53
EE - Estonia	€ / t CO_2	N.A.	38.47	32.11	32.11	32.11
ES - Espania	€ / t CO_2	N.A.	37.54	31.67	31.67	31.67
FI - Finland	€ / t CO_2	N.A.	38.13	31.95	31.95	31.95
GR - Greece	€ / t CO_2	38.56	38.56	32.15	32.15	32.15
HU - Hungary	€ / t CO_2	38.65	38.65	32.19	32.19	32.19
IT - Italy	€ / t CO_2	N.A.	37.82	31.80	31.80	31.80
LT - Lithuania	€ / t CO_2	N.A.	38.99	32.35	32.35	32.35
LV - Latvia	€ / t CO_2	N.A.	38.99	32.35	32.35	32.35
PL - Poland	€ / t CO_2	38.65	38.65	32.19	32.19	32.19
RO - Romania	€ / t CO_2	38.91	38.91	32.31	32.31	32.31
SI - Slovenia	€ / t CO_2	38.56	38.56	32.15	32.15	32.15
SK - Slovakia	€ / t CO_2	38.65	38.65	32.19	32.19	32.19
Average	€ / t CO_2	38.77	38.56	32.15	32.15	32.15

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / t CO_2	45.19	45.19	36.06	36.06	36.06
EE - Estonia	€ / t CO_2	N.A.	43.98	35.51	35.51	35.51
ES - Espania	€ / t CO_2	N.A.	42.75	34.94	34.94	34.94
FI - Finland	€ / t CO_2	N.A.	43.53	35.30	35.30	35.30
GR - Greece	€ / t CO_2	44.10	44.10	35.56	35.56	35.56
HU - Hungary	€ / t CO_2	44.22	44.22	35.62	35.62	35.62
IT - Italy	€ / t CO_2	N.A.	43.12	35.11	35.11	35.11
LT - Lithuania	€ / t CO_2	N.A.	44.67	35.82	35.82	35.82
LV - Latvia	€ / t CO_2	N.A.	44.67	35.82	35.82	35.82
PL - Poland	€ / t CO_2	44.22	44.22	35.62	35.62	35.62
RO - Romania	€ / t CO_2	44.56	44.56	35.77	35.77	35.77
SI - Slovenia	€ / t CO_2	44.10	44.10	35.56	35.56	35.56
SK - Slovakia	€ / t CO_2	44.22	44.22	35.62	35.62	35.62
Average	€ / t CO_2	44.37	44.10	35.56	35.56	35.56

11.2 Annex II: Levelized Fuel Prices

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_t	7.22	15.37	31.46	32.04	35.79
EE - Estonia	€ / MWh_t	N.A.	15.31	31.52	32.10	35.85
ES - Espania	€ / MWh_t	N.A.	17.29	31.68	32.25	36.01
FI - Finland	€ / MWh_t	N.A.	14.16	26.64	27.22	30.98
GR - Greece	€ / MWh_t	7.19	15.32	37.20	37.78	41.54
HU - Hungary	€ / MWh_t	7.20	15.32	38.35	38.93	42.69
IT - Italy	€ / MWh_t	N.A.	15.46	40.17	40.75	44.50
LT - Lithuania	€ / MWh_t	N.A.	15.35	36.85	37.43	41.19
LV - Latvia	€ / MWh_t	N.A.	15.35	36.59	37.17	40.93
PL - Poland	€ / MWh_t	7.20	13.02	29.17	29.75	33.51
RO - Romania	€ / MWh_t	7.21	15.34	31.52	32.09	35.85
SI - Slovenia	€ / MWh_t	7.19	15.32	45.54	46.11	49.87
SK - Slovakia	€ / MWh_t	7.20	15.32	45.50	46.07	49.83
Average	€ / MWh_t	7.20	15.23	35.55	36.13	39.89

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_t	6.85	14.58	30.19	30.77	34.52
EE - Estonia	€ / MWh_t	N.A.	14.56	30.29	30.87	34.62
ES - Espania	€ / MWh_t	N.A.	16.47	30.48	31.06	34.82
FI - Finland	€ / MWh_t	N.A.	13.48	25.61	26.19	29.95
GR - Greece	€ / MWh_t	6.84	14.56	35.75	36.33	40.09
HU - Hungary	€ / MWh_t	6.84	14.56	36.85	37.43	41.18
IT - Italy	€ / MWh_t	N.A.	14.72	38.65	39.22	42.98
LT - Lithuania	€ / MWh_t	N.A.	14.57	35.39	35.97	39.72
LV - Latvia	€ / MWh_t	N.A.	14.57	35.14	35.72	39.48
PL - Poland	€ / MWh_t	6.84	12.37	27.81	28.38	32.14
RO - Romania	€ / MWh_t	6.84	14.57	30.14	30.72	34.47
SI - Slovenia	€ / MWh_t	6.84	14.56	43.76	44.34	48.10
SK - Slovakia	€ / MWh_t	6.84	14.56	43.72	44.30	48.05
Average	€ / MWh_t	6.84	14.47	34.14	34.72	38.47

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_t	5.97	12.71	28.14	28.72	32.47
EE - Estonia	€ / MWh_t	N.A.	12.71	28.30	28.88	32.64
ES - Espania	€ / MWh_t	N.A.	14.42	28.56	29.14	32.90
FI - Finland	€ / MWh_t	N.A.	11.78	23.95	24.53	28.29
GR - Greece	€ / MWh_t	5.97	12.71	33.41	33.99	37.74
HU - Hungary	€ / MWh_t	5.97	12.71	34.43	35.00	38.76
IT - Italy	€ / MWh_t	N.A.	12.88	36.19	36.77	40.53
LT - Lithuania	€ / MWh_t	N.A.	12.71	29.49	30.07	33.82
LV - Latvia	€ / MWh_t	N.A.	12.71	32.80	33.37	37.13
PL - Poland	€ / MWh_t	5.97	10.80	25.97	26.54	30.30
RO - Romania	€ / MWh_t	5.97	12.71	28.13	28.71	32.46
SI - Slovenia	€ / MWh_t	5.97	12.71	40.90	41.48	45.23
SK - Slovakia	€ / MWh_t	5.97	12.71	40.85	41.43	45.18
Average	€ / MWh_t	5.97	12.64	31.62	32.20	35.96

11.3 Annex III: Levelized CO_2 Costs of Electricity

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	26.21	21.02	8.74	8.74	12.72
EE - Estonia	€ / MWh_e	N.A.	20.56	8.61	8.61	12.53
ES - Espania	€ / MWh_e	N.A.	20.09	8.48	8.48	12.34
FI - Finland	€ / MWh_e	N.A.	20.39	8.56	8.56	12.46
GR - Greece	€ / MWh_e	25.69	20.60	8.63	8.63	12.55
HU - Hungary	€ / MWh_e	25.75	20.65	8.64	8.64	12.57
IT - Italy	€ / MWh_e	N.A.	20.23	8.52	8.52	12.40
LT - Lithuania	€ / MWh_e	N.A.	20.82	8.69	8.69	12.64
LV - Latvia	€ / MWh_e	N.A.	20.82	8.69	8.69	12.64
PL - Poland	€ / MWh_e	25.75	20.65	8.64	8.64	12.57
RO - Romania	€ / MWh_e	25.91	20.78	8.67	8.67	12.62
SI - Slovenia	€ / MWh_e	25.69	20.60	8.63	8.63	12.55
SK - Slovakia	€ / MWh_e	25.75	20.65	8.64	8.64	12.57
Average	€ / MWh_e	25.82	20.60	8.63	8.63	12.55

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	36.83	29.54	11.88	11.88	17.29
EE - Estonia	€ / MWh_e	N.A.	28.85	11.73	11.73	17.07
ES - Espania	€ / MWh_e	N.A.	28.16	11.57	11.57	16.84
FI - Finland	€ / MWh_e	N.A.	28.60	11.67	11.67	16.98
GR - Greece	€ / MWh_e	36.06	28.92	11.74	11.74	17.09
HU - Hungary	€ / MWh_e	36.14	28.99	11.76	11.76	17.11
IT - Italy	€ / MWh_e	N.A.	28.36	11.62	11.62	16.91
LT - Lithuania	€ / MWh_e	N.A.	29.24	11.82	11.82	17.20
LV - Latvia	€ / MWh_e	N.A.	29.24	11.82	11.82	17.20
PL - Poland	€ / MWh_e	36.14	28.99	11.76	11.76	17.11
RO - Romania	€ / MWh_e	36.39	29.18	11.80	11.80	17.18
SI - Slovenia	€ / MWh_e	36.06	28.92	11.74	11.74	17.09
SK - Slovakia	€ / MWh_e	36.14	28.99	11.76	11.76	17.11
Average	€ / MWh_e	36.25	28.92	11.74	11.74	17.09

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	42.26	33.89	13.17	13.17	19.17
EE - Estonia	€ / MWh_e	N.A.	32.98	12.97	12.97	18.87
ES - Espania	€ / MWh_e	N.A.	32.06	12.76	12.76	18.57
FI - Finland	€ / MWh_e	N.A.	32.65	12.89	12.89	18.76
GR - Greece	€ / MWh_e	41.24	33.07	12.99	12.99	18.90
HU - Hungary	€ / MWh_e	41.35	33.16	13.01	13.01	18.93
IT - Italy	€ / MWh_e	N.A.	32.34	12.82	12.82	18.66
LT - Lithuania	€ / MWh_e	N.A.	33.50	13.09	13.09	19.04
LV - Latvia	€ / MWh_e	N.A.	33.50	13.09	13.09	19.04
PL - Poland	€ / MWh_e	41.35	33.16	13.01	13.01	18.93
RO - Romania	€ / MWh_e	41.67	33.42	13.07	13.07	19.02
SI - Slovenia	€ / MWh_e	41.24	33.07	12.99	12.99	18.90
SK - Slovakia	€ / MWh_e	41.35	33.16	13.01	13.01	18.93
Average	€ / MWh_e	41.50	33.08	12.99	12.99	18.90

11.4 Annex IV: Levelized Fuel Costs of Electricity

Scenario A	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	16.71	33.71	56.89	57.93	94.19
EE - Estonia	€ / MWh_e	N.A.	33.58	57.00	58.04	94.35
ES - Espania	€ / MWh_e	N.A.	37.92	57.28	58.32	94.76
FI - Finland	€ / MWh_e	N.A.	31.06	48.18	49.22	81.52
GR - Greece	€ / MWh_e	16.65	33.59	67.28	68.32	109.31
HU - Hungary	€ / MWh_e	16.66	33.61	69.35	70.40	112.33
IT - Italy	€ / MWh_e	N.A.	33.91	72.64	73.69	117.12
LT - Lithuania	€ / MWh_e	N.A.	33.66	66.64	67.69	108.38
LV - Latvia	€ / MWh_e	N.A.	33.66	66.17	67.22	107.71
PL - Poland	€ / MWh_e	16.66	28.55	52.75	53.80	88.17
RO - Romania	€ / MWh_e	16.68	33.64	56.99	58.04	94.34
SI - Slovenia	€ / MWh_e	16.65	33.59	82.34	83.39	131.23
SK - Slovakia	€ / MWh_e	16.66	33.61	82.27	83.31	131.13
Average	€ / MWh_e	16.67	33.39	64.29	65.34	104.96

Scenario B	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	15.86	31.98	54.60	55.64	90.86
EE - Estonia	€ / MWh_e	N.A.	31.92	54.77	55.82	91.11
ES - Espania	€ / MWh_e	N.A.	36.13	55.12	56.17	91.62
FI - Finland	€ / MWh_e	N.A.	29.56	46.32	47.36	78.81
GR - Greece	€ / MWh_e	15.83	31.93	64.65	65.70	105.49
HU - Hungary	€ / MWh_e	15.83	31.94	66.64	67.68	108.38
IT - Italy	€ / MWh_e	N.A.	32.29	69.89	70.93	113.11
LT - Lithuania	€ / MWh_e	N.A.	31.96	64.00	65.04	104.54
LV - Latvia	€ / MWh_e	N.A.	31.96	63.55	64.60	103.89
PL - Poland	€ / MWh_e	15.83	27.13	50.28	51.33	84.58
RO - Romania	€ / MWh_e	15.84	31.95	54.50	55.55	90.72
SI - Slovenia	€ / MWh_e	15.83	31.93	79.14	80.18	126.57
SK - Slovakia	€ / MWh_e	15.83	31.94	79.06	80.10	126.45
Average	€ / MWh_e	15.84	31.74	61.73	62.78	101.24

Scenario C	Unit	Lignite USC-PC base load	Hard Coal USC-PC base load	CCGT base load	CCGT intermediate load	GT peak load
BG - Bulgaria	€ / MWh_e	13.82	27.87	50.88	51.93	85.45
EE - Estonia	€ / MWh_e	N.A.	27.88	51.18	52.23	85.89
ES - Espania	€ / MWh_e	N.A.	31.62	51.65	52.69	86.57
FI - Finland	€ / MWh_e	N.A.	25.83	43.31	44.36	74.44
GR - Greece	€ / MWh_e	13.82	27.88	60.41	61.46	99.32
HU - Hungary	€ / MWh_e	13.82	27.88	62.25	63.30	102.00
IT - Italy	€ / MWh_e	N.A.	28.24	65.45	66.49	106.65
LT - Lithuania	€ / MWh_e	N.A.	27.87	53.33	54.37	89.01
LV - Latvia	€ / MWh_e	N.A.	27.87	59.31	60.35	97.71
PL - Poland	€ / MWh_e	13.82	23.68	46.96	48.00	79.74
RO - Romania	€ / MWh_e	13.82	27.87	50.87	51.91	85.43
SI - Slovenia	€ / MWh_e	13.82	27.88	73.96	75.01	119.04
SK - Slovakia	€ / MWh_e	13.82	27.88	73.87	74.91	118.90
Average	€ / MWh_e	13.82	27.71	57.19	58.23	94.63

11.5 Annex V: Results for power plant investment competition between EU and non-EU countries

Bulgaria - Turkey

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Bulgaria	Turkey	Turkey	Bulgaria	Turkey	Turkey	Bulgaria	Turkey	Turkey
Item		Lignite USC-PC base load	Lignite USC-PC base load	Lignite USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh_e	71.0	47.4	71.0	83.1	86.5	n.a.	147.0	158.7	n.a.
Levelized marginal cost	€ / MWh_e	44.9	18.6	17.6	70.0	71.4	n.a.	111.9	114.0	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	26.2	0.0	0.0	8.7	0.0	n.a.	12.7	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	0.4	0.8	n.a.	0.7	n.a.	n.a.	2.5	n.a.
WACC (discount rate, real)	%	4.6%	5.1%	13.2%	4.6%	5.1%	n.a.	4.6%	5.1%	n.a.
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Bulgaria	Turkey	Turkey	Bulgaria	Turkey	Turkey	Bulgaria	Turkey	Turkey
Item		CCGT - base load	Lignite USC-PC base load	Lignite USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh_e	77.7	46.6	77.7	84.0	83.9	84.0	148.2	154.9	n.a.
Levelized marginal cost	€ / MWh_e	69.8	17.8	17.1	70.9	68.8	68.8	113.2	110.2	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	11.9	0.0	0.0	11.9	0.0	0.0	17.3	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	0.4	0.9	n.a.	0.7	0.7	n.a.	2.5	n.a.
WACC (discount rate, real)	%	4.6%	5.1%	15.4%	4.6%	5.1%	5.2%	4.6%	5.1%	n.a.
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Bulgaria	Turkey	Turkey	Bulgaria	Turkey	Turkey	Bulgaria	Turkey	Turkey
Item		CCGT - base load	Lignite USC-PC base load	Lignite USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh_e	75.3	44.6	75.3	81.6	79.7	81.6	144.7	148.7	n.a.
Levelized marginal cost	€ / MWh_e	67.4	15.8	15.6	68.4	64.6	64.5	109.6	104.0	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	13.2	0.0	0.0	13.2	0.0	0.0	19.2	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	0.4	0.9	n.a.	0.7	0.8	n.a.	2.5	n.a.
WACC (discount rate, real)	%	4.6%	5.1%	15.1%	4.6%	5.1%	6.7%	4.6%	5.1%	n.a.

Greece - Turkey

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Greece	Turkey	Turkey	Greece	Turkey	Turkey	Greece	Turkey	Turkey
		Lignite	Lignite	Lignite	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	USC-PC						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	73.0	47.1	73.0	94.9	86.6	94.9	170.7	156.7	170.7
Levelized marginal cost	€ / MWh_e	44.3	18.6	17.5	80.3	71.4	67.3	126.9	114.0	110.3
Levelized CO_2 certificate cost	€ / MWh_e	25.7	0.0	0.0	8.6	0.0	0.0	12.6	0.0	0.0
Levelized transmission cost	€ / MWh_e	n.a.	0.5	1.2	n.a.	1.0	2.1	n.a.	3.7	565.1%
WACC (discount rate, real)	%	5.1%	5.1%	13.8%	5.1%	5.1%	13.8%	5.1%	5.1%	9.8%
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Greece	Turkey	Turkey	Greece	Turkey	Turkey	Greece	Turkey	Turkey
		Lignite	Lignite	Lignite	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	USC-PC						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	82.5	46.3	82.5	95.4	84.0	95.4	171.4	152.9	171.4
Levelized marginal cost	€ / MWh_e	53.8	17.8	17.0	80.8	68.8	65.7	127.6	110.2	107.3
Levelized CO_2 certificate cost	€ / MWh_e	36.1	0.0	0.0	11.7	0.0	0.0	17.1	0.0	0.0
Levelized transmission cost	€ / MWh_e	n.a.	0.5	1.5	n.a.	1.0	2.2	n.a.	3.7	606.5%
WACC (discount rate, real)	%	5.1%	5.1%	16.8%	5.1%	5.1%	15.1%	5.1%	5.1%	10.8%
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Greece	Turkey	Turkey	Greece	Turkey	Turkey	Greece	Turkey	Turkey
		CCGT	Lignite	CCGT	CCGT	CCGT	CCGT	GT	GT	GT
		-	USC-PC	-						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	85.5	44.3	85.5	92.4	79.7	92.4	167.0	146.7	167.0
Levelized marginal cost	€ / MWh_e	76.7	15.8	62.5	77.8	64.6	64.0	123.2	104.0	103.5
Levelized CO_2 certificate cost	€ / MWh_e	13.0	0.0	0.0	13.0	0.0	0.0	18.9	0.0	0.0
Levelized transmission cost	€ / MWh_e	n.a.	0.5	1.8	n.a.	1.0	2.1	n.a.	3.7	600.0%
WACC (discount rate, real)	%	5.1%	5.1%	20.3%	5.1%	5.1%	14.3%	5.1%	5.1%	10.6%

Hungary - Serbia

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Hungary	Serbia	Serbia	Hungary	Serbia	Serbia	Hungary	Serbia	Serbia
		Lignite	Lignite	Lignite	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	USC-PC						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	168.0	152.4	168.0
Levelized marginal cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	129.9	112.5	108.4
Levelized CO_2 certificate cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	12.6	0.0	0.0
Levelized transmission cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.5	578.6%
WACC (discount rate, real)	%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	5.0%	4.6%	10.1%
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Hungary	Serbia	Serbia	Hungary	Serbia	Serbia	Hungary	Serbia	Serbia
		Lignite	Lignite	Lignite	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	USC-PC						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	168.6	148.6	168.6
Levelized marginal cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	130.5	108.7	105.5
Levelized CO_2 certificate cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	17.1	0.0	0.0
Levelized transmission cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.5	617.6%
WACC (discount rate, real)	%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	5.0%	4.6%	11.0%
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Hungary	Serbia	Serbia	Hungary	Serbia	Serbia	Hungary	Serbia	Serbia
		Lignite	Lignite	CCGT	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	-						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	164.0	142.3	164.0
Levelized marginal cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	125.9	102.5	101.9
Levelized CO_2 certificate cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	18.9	0.0	0.0
Levelized transmission cost	€ / MWh_e	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.5	606.8%

Italy - Montenegro

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Montenegro	Montenegro	Italy	Montenegro	Montenegro	Italy	Montenegro	Montenegro
		Hard Coal USC-PC	Hard Coal USC-PC	Hard Coal USC-PC	CCGT	CCGT	CCGT	GT	GT	GT
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	82.1	66.8	82.1	100.8	n.a.	n.a.	179.3	n.a.	n.a.
Levelized marginal cost	€ / MWh_e	55.3	34.9	33.7	85.5	n.a.	n.a.	134.5	n.a.	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	20.2	n.a.	0.0	8.5	n.a.	n.a.	12.4	n.a.	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.6	14.2	n.a.	16.8	n.a.	n.a.	60.6	n.a.
WACC (discount rate, real)	%	5.5%	4.6%	9.1%	5.5%	4.6%	n.a.	5.5%	4.6%	n.a.
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Montenegro	Montenegro	Italy	Montenegro	Montenegro	Italy	Montenegro	Montenegro
		Hard Coal USC-PC	Hard Coal USC-PC	Hard Coal USC-PC	CCGT	CCGT	CCGT	GT	GT	GT
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	88.6	65.0	88.6	101.1	n.a.	n.a.	179.8	n.a.	n.a.
Levelized marginal cost	€ / MWh_e	61.8	33.1	32.3	85.9	n.a.	n.a.	135.0	n.a.	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	28.4	n.a.	0.0	11.6	n.a.	n.a.	16.9	n.a.	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.6	16.8	n.a.	16.8	n.a.	n.a.	60.6	n.a.
WACC (discount rate, real)	%	5.5%	4.6%	11.0%	5.5%	4.6%	n.a.	5.5%	4.6%	n.a.
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Montenegro	Montenegro	Italy	Montenegro	Montenegro	Italy	Montenegro	Montenegro
		Hard Coal USC-PC	Hard Coal USC-PC	Hard Coal USC-PC	CCGT	CCGT	CCGT	GT	GT	GT
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	88.6	60.9	88.6	97.9	n.a.	n.a.	175.1	n.a.	n.a.
Levelized marginal cost	€ / MWh_e	61.7	29.0	28.9	82.6	n.a.	n.a.	130.3	n.a.	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	32.3	n.a.	0.0	12.8	n.a.	n.a.	18.7	n.a.	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.6	17.9	n.a.	16.8	n.a.	n.a.	60.6	n.a.
WACC (discount rate, real)	%	5.5%	4.6%	11.8%	5.5%	4.6%	n.a.	5.5%	4.6%	n.a.

Italy - Algeria

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Algeria	Algeria	Italy	Algeria	Algeria	Italy	Algeria	Algeria
		Hard Coal	Hard Coal	CCGT	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	-						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	82.1	67.7	82.1	100.8	84.1	100.8	179.3	182.8	n.a.
Levelized marginal cost	€ / MWh_e	55.3	34.7	50.3	85.5	54.1	51.7	134.5	88.8	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	20.2	0.0	0.0	8.5	0.0	0.0	12.4	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.4	17.9	n.a.	16.2	27.4	n.a.	58.3	n.a.
WACC (discount rate, real)	%	5.5%	5.3%	12.8%	5.5%	5.3%	11.6%	5.5%	5.3%	n.a.
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Algeria	Algeria	Italy	Algeria	Algeria	Italy	Algeria	Algeria
		Hard Coal	Hard Coal	CCGT	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	-						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	88.6	66.1	88.6	101.1	82.2	101.1	179.8	180.0	n.a.
Levelized marginal cost	€ / MWh_e	61.8	33.0	48.5	85.9	52.2	50.5	135.0	86.0	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	28.4	0.0	0.0	11.6	0.0	0.0	16.9	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.4	22.7	n.a.	16.2	28.4	n.a.	58.3	n.a.
WACC (discount rate, real)	%	5.5%	5.3%	16.7%	5.5%	5.3%	12.1%	5.5%	5.3%	n.a.
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Algeria	Algeria	Italy	Algeria	Algeria	Italy	Algeria	Algeria
		Hard Coal	Hard Coal	CCGT	CCGT	CCGT	CCGT	GT	GT	GT
		USC-PC	USC-PC	-						
Item		base load	base load	base load	intermediate load	intermediate load	intermediate load	peak load	peak load	peak load
Levelized composite cost	€ / MWh_e	88.6	62.0	88.6	97.9	79.1	97.9	175.1	175.5	n.a.
Levelized marginal cost	€ / MWh_e	61.7	29.0	47.4	82.6	49.1	48.7	130.3	81.5	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	32.3	0.0	0.0	12.8	0.0	0.0	18.7	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.4	23.4	n.a.	16.2	27.5	n.a.	58.3	n.a.
WACC (discount rate, real)	%	5.5%	5.3%	17.2%	5.5%	5.3%	11.6%	5.5%	5.3%	n.a.

Italy - Albania

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Albania	Albania	Italy	Albania	Albania	Italy	Albania	Albania
Item		Hard Coal USC-PC base load	Hard Coal USC-PC base load	Hard Coal USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh_e	82.1	66.6	82.1	100.8	n.a.	n.a.	179.3	n.a.	n.a.
Levelized marginal cost	€ / MWh_e	55.3	34.8	33.6	85.5	n.a.	n.a.	134.5	n.a.	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	20.2	n.a.	0.0	8.5	n.a.	n.a.	12.4	n.a.	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.3	13.7	n.a.	16.1	n.a.	n.a.	57.9	n.a.
WACC (discount rate, real)	%	5.5%	4.9%	9.5%	5.5%	4.9%	n.a.	5.5%	4.9%	n.a.
Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Albania	Albania	Italy	Albania	Albania	Italy	Albania	Albania
Item		Hard Coal USC-PC base load	Hard Coal USC-PC base load	Hard Coal USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh_e	88.6	64.9	88.6	101.1	n.a.	n.a.	179.8	n.a.	n.a.
Levelized marginal cost	€ / MWh_e	61.8	33.1	32.3	85.9	n.a.	n.a.	135.0	n.a.	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	28.4	n.a.	0.0	11.6	n.a.	n.a.	16.9	n.a.	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.3	16.2	n.a.	16.1	n.a.	n.a.	57.9	n.a.
WACC (discount rate, real)	%	5.5%	4.9%	11.5%	5.5%	4.9%	n.a.	5.5%	4.9%	n.a.
Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Italy	Albania	Albania	Italy	Albania	Albania	Italy	Albania	Albania
Item		Hard Coal USC-PC base load	Hard Coal USC-PC base load	Hard Coal USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh_e	88.6	60.8	88.6	97.9	n.a.	n.a.	175.1	n.a.	n.a.
Levelized marginal cost	€ / MWh_e	61.7	29.0	28.9	82.6	n.a.	n.a.	130.3	n.a.	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	32.3	n.a.	0.0	12.8	n.a.	n.a.	18.7	n.a.	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	8.3	17.3	n.a.	16.1	n.a.	n.a.	57.9	n.a.
WACC (discount rate, real)	%	5.5%	4.9%	12.3%	5.5%	4.9%	n.a.	5.5%	4.9%	n.a.

Romania - Turkey

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Romania	Turkey	Turkey	Romania	Turkey	Turkey	Romania	Turkey	Turkey
		Lignite USC-PC base load	Hard Coal USC-PC base load	Hard Coal USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Item										
Levelized composite cost	€ / MWh_e	71.4	69.9	71.4	83.3	104.2	n.a.	147.8	222.0	n.a.
Levelized marginal cost	€ / MWh_e	44.5	35.0	34.9	69.8	71.4	n.a.	111.6	114.0	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	25.9	0.0	0.0	8.7	0.0	n.a.	12.6	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	9.5	10.0	n.a.	18.4	n.a.	n.a.	66.2	n.a.
WACC (discount rate, real)	%	4.9%	5.1%	5.5%	4.9%	5.1%	n.a.	4.9%	5.1%	n.a.

Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Romania	Turkey	Turkey	Romania	Turkey	Turkey	Romania	Turkey	Turkey
		CCGT - base load	Hard Coal USC-PC base load	Hard Coal USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Item										
Levelized composite cost	€ / MWh_e	77.7	68.3	77.7	84.2	101.6	n.a.	149.1	218.2	n.a.
Levelized marginal cost	€ / MWh_e	69.7	33.3	33.0	70.7	68.8	n.a.	112.9	110.2	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	11.8	0.0	0.0	11.8	0.0	n.a.	17.2	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	9.5	12.9	n.a.	18.4	n.a.	n.a.	66.2	n.a.
WACC (discount rate, real)	%	4.9%	5.1%	7.7%	4.9%	5.1%	n.a.	4.9%	5.1%	n.a.

Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Romania	Turkey	Turkey	Romania	Turkey	Turkey	Romania	Turkey	Turkey
		CCGT - base load	Hard Coal USC-PC base load	Hard Coal USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Item										
Levelized composite cost	€ / MWh_e	75.4	64.2	75.4	81.8	97.4	n.a.	145.7	212.1	n.a.
Levelized marginal cost	€ / MWh_e	67.3	29.3	29.2	68.3	64.6	n.a.	109.5	104.0	n.a.
Levelized CO_2 certificate cost	€ / MWh_e	13.1	0.0	0.0	13.1	0.0	n.a.	19.0	0.0	n.a.
Levelized transmission cost	€ / MWh_e	n.a.	9.5	13.4	n.a.	18.4	n.a.	n.a.	66.2	n.a.
WACC (discount rate, real)	%	4.9%	5.1%	8.1%	4.9%	5.1%	n.a.	4.9%	5.1%	n.a.

Romania - Serbia

		Base load			Intermediate load			Peak Load		
Scenario A		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Romania	Serbia	Serbia	Romania	Serbia	Serbia	Romania	Serbia	Serbia
Item		Lignite USC-PC base load	Lignite USC-PC base load	Lignite USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh$_e$	71.4	45.7	71.4	83.3	84.8	n.a.	147.8	153.1	n.a.
Levelized marginal cost	€ / MWh$_e$	44.5	18.7	17.6	69.8	70.4	n.a.	111.6	112.5	n.a.
Levelized CO_2 certificate cost	€ / MWh$_e$	25.9	0.0	0.0	8.7	0.0	n.a.	12.6	0.0	n.a.
Levelized transmission cost	€ / MWh$_e$	n.a.	0.5	1.2	n.a.	1.0	n.a.	n.a.	3.5	n.a.
WACC (discount rate, real)	%	4.9%	4.6%	13.5%	4.9%	4.6%	n.a.	4.9%	4.6%	n.a.

Scenario B		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Romania	Serbia	Serbia	Romania	Serbia	Serbia	Romania	Serbia	Serbia
Item		CCGT - base load	Lignite USC-PC base load	Lignite USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh$_e$	77.7	44.9	77.7	84.2	82.2	84.2	149.1	149.2	n.a.
Levelized marginal cost	€ / MWh$_e$	69.7	17.8	17.1	70.7	67.8	67.0	112.9	108.7	n.a.
Levelized CO_2 certificate cost	€ / MWh$_e$	11.8	0.0	0.0	11.8	0.0	0.0	17.2	0.0	n.a.
Levelized transmission cost	€ / MWh$_e$	n.a.	0.5	1.4	n.a.	1.0	1.2	n.a.	3.5	n.a.
WACC (discount rate, real)	%	4.9%	4.6%	15.6%	4.9%	4.6%	6.9%	4.9%	4.6%	n.a.

Scenario C		EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven	EU	Non-EU	Non-EU breakeven
		Romania	Serbia	Serbia	Romania	Serbia	Serbia	Romania	Serbia	Serbia
Item		CCGT - base load	Lignite USC-PC base load	Lignite USC-PC base load	CCGT intermediate load	CCGT intermediate load	CCGT intermediate load	GT peak load	GT peak load	GT peak load
Levelized composite cost	€ / MWh$_e$	75.4	42.8	75.4	81.8	77.9	81.8	145.7	143.0	145.7
Levelized marginal cost	€ / MWh$_e$	67.3	15.8	15.6	68.3	63.5	63.3	109.5	102.5	102.4
Levelized CO_2 certificate cost	€ / MWh$_e$	13.1	0.0	0.0	13.1	0.0	0.0	19.0	0.0	0.0
Levelized transmission cost	€ / MWh$_e$	n.a.	0.5	1.3	n.a.	1.0	1.3	n.a.	3.5	386.3%
WACC (discount rate, real)	%	4.9%	4.6%	15.3%	4.9%	4.6%	7.8%	4.9%	4.6%	5.5%