Project No 213744

SECURE
Security of Energy Considering its Uncertainty, Risk and Economic implications

SP1 – Cooperation
Collaborative project
Small or medium-scale focused research project

DELIVERABLE No 5.6.6

Final Report of WP 5.6

Due date of deliverable: end of March 2010
Actual submission date: 25 February 2011

Start date of project: 1/1/2008 Duration: 36 months

Organisation name of lead contractor for this deliverable: RSE (Ricerca sul Sistema Energetico)

Revision: 0

Project co-funded by the European Commission within the Seventh Framework Programme		
Dissemination level		
PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential, only for members of the consortium (including the Commission Services)	

Final Report of WP 5.6

RSE (Ricerca sul Sistema Energetico) with contributions of FEEM, ERIRAS, RAMBOLL and OME

Table of Contents

1 Introduction

This report summarizes the results obtained by Work Package 5.6 – *"Development and application of specific tools for energy security in the Electricity Sector"* of the SECURE project concerning the following topics, dealt with in the different tasks of the work package:

- costs of electricity interruptions,
- assessment of the impact of gas shortages risks on the power sector,
- optimisation of transmission infrastructure investments in the EU power sector,
- role and responsibilities of TSOs for security of supply,
- electricity security of supply with increased presence of distributed generation.

Finally, some general policy recommendations concerning security of supply in the electricity sector are reported.

2 Costs of electricity interruptions

One of the main tasks of the electricity industry is to provide reliable electricity to customers at a reasonable and competitive price. Since worldwide, and mostly in developed areas and countries, the share of electricity to total energy consumption is growing, higher quality (reliability) levels of electricity supply become an unavoidable request to the utilities. Indeed supply interruptions, anyway theoretically possible, are less and less accepted by customers and society mainly because their socioeconomic effects are heavier and heavier.

More in general, very severe outages and blackouts that occurred in the past years in the United States and in Europe clearly showed that, besides the price of electricity, Quality of Service (in terms of reliability / continuity of supply) is also a very important issue for customers and society as a whole. Therefore, regulators and institutions are strongly promoting the improvement of electricity quality of service.

Thus reliability of supply and its value are key factors for the decision making process underlying expansion plans not only of electricity generation systems but also of transmission and distribution networks.

It is evident that low levels of investment can result in unreliable supply (unacceptable low quality), while excessive investments can result in unnecessary expenditures with a resulting increase of the cost of electricity to customers. Following the radical changes occurred in the institutional framework of the electricity supply industry since early 90's of the past century, it is nowadays widely recognized that investments related to the provision of electricity quality of service must be carefully evaluated through an explicit cost-benefit analysis that provides the basis for answering the economic question: *How much reliability is adequate from the customer's perspective?*.

To answer this question it is necessary to move from a "criteria-based" planning approach to a "value-based" planning approach, by accounting for both utility's and customer's perspectives.

Moreover, it has to be taken into account that the continuity of supply to the final consumers can no more benefit of the coordination among Generation, Transmission and Distribution sectors, as in the previous monopolistic and vertically integrated framework, because they are now unbundled and autonomous from both the regulatory and the economic point of view. Therefore, the investment optimization process is carried out separately for the G, T and D segments and so three independent optima are calculated, thus resulting in an overall quasi-optimum quality level for consumers.

In a liberalized framework, optimization of the quality level and of related investments can be based on the fact that, from the consumer's perspective, the total cost of the electric service consists of two components: cost of service received, proportional to the cost borne by utility, and the cost of service interruptions (that is the cost of unreliability), which are non linear functions of the reliability level, as shown in Figure 1.

The cost-of-service received, that is the cost borne by the utility to provide customers with electric service at a given quality level, rapidly increases as quality (continuity) grows while, on the contrary, customer's cost due to interruptions is very high when reliability level is low and it rapidly decreases as reliability grows.

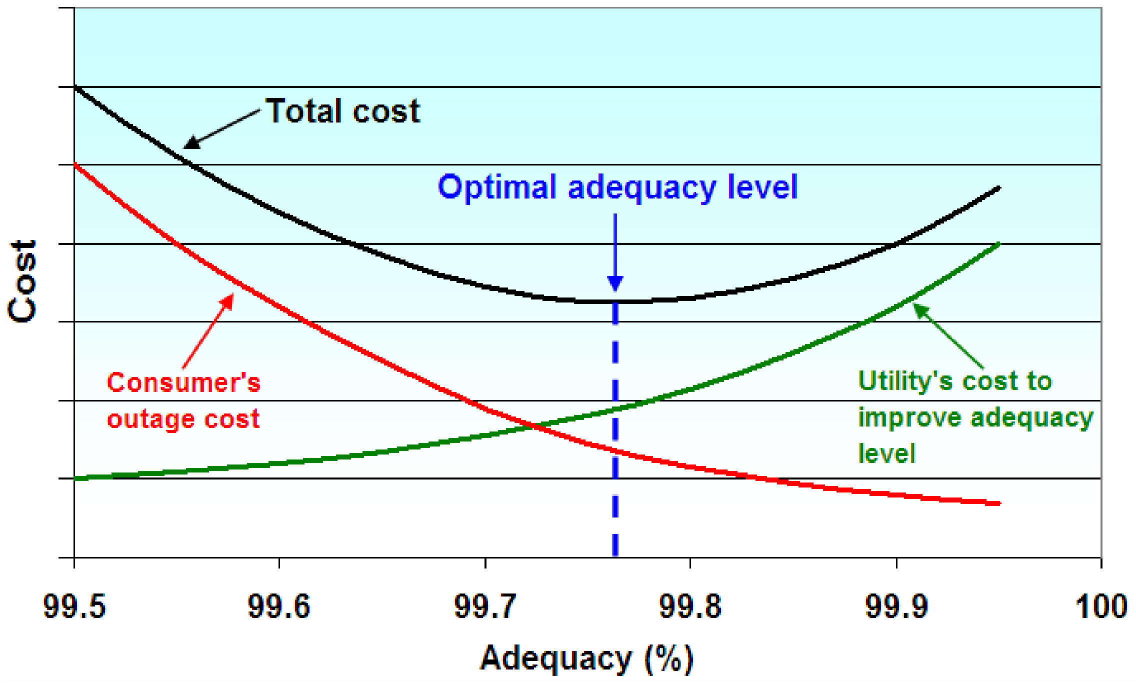

Figure 1: Adequacy optimization in a power system.

Consumers are then best served when their total cost is minimized, that is in the condition defined by equating the marginal cost and the marginal value of service reliability.

The assessment of the best compromise between additional investment costs and corresponding benefits to consumers needs to quantitatively determine the *value of quality* (or of *adequacy*). This is a very complex task and it cannot be implemented as a direct method mainly because no market exists for the quality of electricity supply or, conversely, for interruptions of that supply.

At present, a usually adopted approach to get over this obstacle is to assess the reverse, that is the cost associated to lack of continuity, being aware that the latter is not identical to the value of quality although representative of it, perhaps a lower bound.

In the framework of the SECURE project (see [1] for additional details) a survey has been carried out aimed at investigating and discussing methodologies and techniques used worldwide to assess the cost incurred by customers due to supply interruptions and at collecting the results of their application to real power systems. This in order to provide a reference framework enabling to quantify the economic index Cost of Energy Not Supplied (CENS), also known as VOLL (Value Of Lost Load) or IEAR (Interrupted Energy Assessment Rate).

To this aim, the study has been mainly focused on four topics, discussed in the following:

- the costs of interruptions and the relevant indicators,
- the approaches and methods to assess them,
- the regulation of the quality of service and its impact on continuity of supply,
- the available estimates of interruption unit costs in the European context.

2.1 The cost of interruptions: main factors and indices

The cost of supply interruptions depends on many factors relevant to the consumer categories and to the interruption characteristics and they must be measured through suitable quantitative indices.
The cost of supply interruptions is related to the consequences (economic losses) incurred by consumers when an electricity shortage occurs. In particular, consumer's interruption costs depend on the:

- *type of consumer*, such as industrial, commercial, residential, etc. that differ in their dependency on electricity;
- *interruption characteristics*, such as time of occurrence, duration, advance notification or not, extent, etc.
- *perceived reliability level*, that is strongly determined by the incidence of interruptions in the past (the more structural interruptions took place previously, the lower the perceived reliability) and by the level of socioeconomic development and welfare.

As a result, interruption cost indicators are not quantified as a single value, but rather they can imply a large range of values dependent on the relative importance of these factors.
Useful indices to quantitatively represent the economic losses due to interruptions can be expressed in terms of €/interruption, €/kW of lost peak load, €/kWh of annual energy consumed, €/kWh of energy not supplied. Three indices are most frequently used and referenced in the literature:

- IEAR (*Interruption Energy Assessment Rate*): it is a system-wide interruption cost index. It is expressed in €/kWh and, therefore, together with the adequacy index EENS (*Expected Energy Not Supplied per year*), it provides an estimation of the expected annual economic damage incurred on average by customers due to interruptions.
- VOLL (*Value Of Lost Load*): in the literature, its prevailing meaning is conceptually equivalent to the IEAR, even though it is sometimes intended as the value (€/kWh) an average consumer puts on an unsupplied kWh of energy, rather than the incurred cost.
- WTP (*Willingness To Pay*): it represents the customer willingness to pay to improve its continuity of supply, by decreasing frequency and/or duration of interruptions and by avoiding specific types of accidents, e.g. those ones lasting more than a defined upper limit. WTP may be expressed in €/kWh of consumed energy, if it represents the propensity of customers to pay for an increase of their electricity bills in order to have a given quality improvement, or as €/event, if the customer's goal is to reduce or to avoid interruptions at all.

2.2 Approaches and methods to assess interruption cost indices

The cost of supply interruptions is related to the economic consequences incurred by consumers when an electricity shortage occurs. Suitable approaches and methodologies

have been developed in the last decades to assess interruption cost indices and are now available and used by institutional bodies for regulatory purposes and by utilities for expansion planning studies.
The approaches are categorized according to four typologies:

a) Revealed preferences, whose main advantage is that relatively accurate data can be collected through observations and analysis of consumers' market behavior, while the main drawback is that only large consumers can provide suitable signals.
b) Stated preferences, based on customer surveys. This approach has two main advantages: firstly, it provides utilities with interruption cost data suitable for planning purposes, and secondly, it is customer based / bottom-up, and therefore it directly incorporates customers' preferences. The main drawback is the high cost to implement it.
c) Proxy methods (including the production function approach), whose main advantage is that they are quite easy to apply, making use of readily available data, such as Gross National Product, total energy consumption, sector production functions, etc., and moreover they are practically inexpensive to implement. The main drawback is that most of them are based on limiting and sometimes unrealistic assumptions.
d) Case studies, based on collection of as much data as possible immediately after the occurrence of large-scale power supply interruptions. Their main advantage is that interruption cost values are directly related to consumers' experience of real interruptions, rather than hypothetical scenarios. The fundamental drawback is that the number of case studies and relevant data sets is very small and therefore the meaningfulness of the calculated interruption cost indices may be relatively poor.

As far as the assessment of interruption cost indices is concerned, it has to be noted that the Stated Preferences approach is the most frequently used by utilities and regulators. On the basis of customer surveys, utilities usually collect cost data for each interruption type and duration. In this case, the assessment of system interruption cost indices in principle requires three computing steps:

a) Processing of raw collected data, that mainly consists of normalisation of individual customer data either by annual consumed energy (MWh) or by peak load demand (MW), in order to make it possible and consistent the subsequent grouping or aggregation process into customer categories (sectors).
b) Setting up of customer interruption cost models, usually based on Customer Damage Functions (CDF) that represent the normalized Cost of Interruptions as a function of outage duration and parameterized according to consumer and outage characteristics. CDFs are usually formulated at Consumer level (CDF), at Sector level (SCDF), by aggregating all consumers of the same sector and weighting the relevant CDFs, and finally at Composite Consumer level (CCDF), by weighting and combining the previously determined SCDFs.
c) Computing of power system interruption cost indices, that involves the convolution of interruption cost models, of load models and of system model, concerning interruption statistics and power flows analysis.

In particular, computing of interruption cost indices requires the availability of both frequency and duration of interruptions and of the corresponding load shortages.

Should an "ex post" interruption cost investigation be carried out, the system information on the frequency and duration of interruptions, as well as on the total energy not supplied due to outages of network components, can be obtained from recording and processing operation data.
When, on the contrary, an "ex ante" interruption cost analysis is requested, as in the case of network expansion planning, power system interruption indices must be assessed by using suitable network modelling and computing procedures, based on either state enumeration methods or on probabilistic simulations, such as Montecarlo sampling techniques.

2.3 Regulation of electricity quality of supply

The key motivation for quality regulation in the electricity sector mainly lies in the strong incentives to cost reduction by utilities, induced by privatisation and price capped tariffs. In this context, indeed, if quality is not enforced or not incentivized, operators could reduce network investments, thus causing a lower quality of service for the final consumers. Incentive regulation for quality can ensure that cost cuts required by price-cap regimes are not achieved at the expense of quality itself.
In some European countries national regulatory authorities have started implementing quality regulation schemes since the beginning of the last decade.
The reference reliability indicators usually considered are SAIDI (*System Average Interruption Duration Index*), SAIFI (*System Average Interruption Frequency Index*) and ENS (*Energy Not Supplied*).
As far as the distribution service is concerned, at the end of 2005 incentive/penalty schemes were in place in 8 countries out of the 19 surveyed by CEER (Council of European Energy Regulators): Italy (from 2000), Norway and Ireland (from 2001), Great Britain (from 2002), Hungary and Portugal (from 2003), Sweden (from 2004), and Estonia (from 2005). Meanwhile, some other countries expressed interest for setting up an incentive scheme in the future, such as Finland, France, Lithuania, Poland, Spain, and Slovenia.
In those countries where quality incentive schemes have been adopted, beneficial effects on supply continuity indicators have been experienced, as summarized below:

SAIDI:	GB: -19% (3 years), HU: -65 % (5 years), IT: -53% (5 years)
SAIFI:	GB: -15% (3 years), IT: -34% (5 years)
ENS:	NO: -40% (4 years)
Average continuity:	IE: +28% (5 years)

The analysis of the adopted regulation schemes allows to obtain the VOLL values that have been either explicitly or implicitly assumed by Regulators for their formulation. According to the 3rd Benchmarking Report issued by CEER in 2005 and to British and Italian Regulators' documents, the quality incentive schemes adopted in six countries assume the values of VOLL shown in Table 1 below.

Country	Sector	VOLL (reference year: 2003)	
		€/kWh not supplied	€/kW interrupted
Great Britain	Distribution: all sectors Transmission: all sectors	4.18 52.9	
Italy	Transmission: all sectors	15.0	
Sweden	Distribution: urban suburban rural	12.0 8.8 7.4	2.5 1.9 1.6
Norway	Distribution: residential commercial industrial	0.96 11.8 7.9	
Ireland	Distribution: all sectors	7.2	
Portugal	Distribution: all sectors	1.5	

Table 1: VOLL values adopted for quality regulation schemes.

2.4 Estimates of VOLL values

For some European countries, the survey allowed to obtain the VOLL values shown in Table 2.
Moreover, the University of Bath estimates VOLL values at the horizon year 2030 shown in the following Table 3.
Some authors warn about the fact that VOLL do not coincide with the value of quality (reliability), since it can be better considered as its lower bound.
The values of VOLL available in the literature have been obtained through different approaches and computing methodologies and, moreover, they are expressed in different currencies and are referred to different years. Then, it is difficult to compare them to each other.
However some general conclusions can be drawn:

- VOLL tends to be higher for developed countries than for developing ones, mainly depending on the respective shares of electricity to total energy consumption;
- such differences could be smoothed by expressing VOLL in PPP (Power Purchase Parity) rather than in US$ and current international exchange rates;
- the spread in VOLL values in absolute terms, and thus the “risk” for a high value of VOLL, is higher for more developed countries than for developing ones; in any case their distributions seem to be left-skewed so that median values are closer to lower bound than to upper bound of each relevant interval.

Country	Sector	VOLL	Approach	Remarks
Great Britain	Residential Industrial ------------- All sectors ------------- Al sectors	2.5 ÷ 9 US$(2004)/kWh 4 ÷ 10 US$(2004)/kWh ---------------------------------- 4 ÷ 6 US$(1993)/kWh ---------------------------------- 11 ÷ 13 £(1996)/kWh	Survey	Obtained from CDFs and SCDFs of a 1993 survey Expected VOLL through probability method and 1993 data
Sweden	Residential Commercial Industry ------------- All sectors	2.5 ÷ 5 US$(2004)/kWh 49.0 US$(2004)/kWh 6.2÷18.2US$(2004)/kWh ---------------------------------- **WTP** 9.4 ÷ 13.5 SEK(2004) per 1h outage	Survey	
Norway	Residential Commercial ------------- All sectors	1.0 US$(2004)/kWh 5.0 US$(2004)/kWh ---------------------------------- 3 ÷ 4 US$(1991)/kWh	Survey	
The Netherlands	All sectors	10.0 US$(2004)/kWh		
Finland	All sectors	2.0 ÷3.8 US$(1999)/kWh	Survey	VOLL as a decreasing function of outage duration
Ireland	Residential Others Average	62.0 €(2007)/kWh 9.0 €(2007)/kWh 40.0 €(2007)/kWh	Proxy method	VOLL assessment by using linear production functions
Slovenia	All sectors	1.0 ÷3.0 €(2007)/kWh	SECI inquiry	
SEE Area: **Albania** **Bulgaria** **Croatia** **Romania** **UNMIK**	All sectors	 0.5 €(2007)/kWh 2.0 €(2007)/kWh 2.56 €(2007)/kWh 0.8 €(2007)/kWh 0.4 €(2007)/kWh	SECI inquiry	

Table 2: VOLL values resulting from the literature survey.

VOLL in US$(2007)/kWh Entire economy (all consumer's sectors)		
	Maximum range	**90% CL range**
Developed countries	**4 ÷ 40**	**5 ÷ 25**
Developing countries	**1 ÷ 10**	**2 ÷ 5**

Table 3: Estimated VOLL values at year 2030 (maximum range and 90% confidence limit range; source: University of Bath).

3 Assessment of the impact of gas shortages risks on the power sector

Electricity security of supply remarkably depends on fuel security of supply. It is widely recognized that the role of gas in power generation in the EU Member States is growing today and will significantly increase in the future, determining risks of insecure electricity supply in case of gas supply shortages.

Within this context, this study quantifies the impact on the overall European power system of possible gas supply shortages occurring in two countries whose power generation is largely based on natural gas, namely Italy and Hungary (see [2] for additional details). The reference year considered for the shortage scenarios is 2015.

The impact assessment, carried out using a simulation model of the European power system, is focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO_2 emissions) deriving from the redispatching of power generation (with possible fuel substitution) necessary to face the gas shortage, taking into account cross-border electricity exchanges.

In the following, the results of the study will be reported according to the six-steps methodology defined within the SECURE project.

3.1 STEP 1: threat identification and assessment

The threat taken into account in this study is a gas supply shortage occurring in two countries whose power generation is largely based on natural gas, namely Italy and Hungary. The reference year considered for the shortage scenarios is 2015.

In particular, the gas shortage scenario for Italy assumes an interruption of supply from the *TransMed "Enrico Mattei"* pipeline connecting Algeria to Italy (entry point at Mazara del Vallo, Sicily) via Tunisia.

This pipeline has an annual maximum capacity of 33.5 bcm, and the interruption is assumed for the 5 months between November and March, i.e. the most critical ones in terms of gas consumption in Italy, due to heating demand.

As for the assessment of the probability of occurrence of this threat, it must be noticed that it is not so remote as it would seem at a first glance. In fact, on December 19, 2008, one of the five lines composing *TransMed* was damaged by the anchor of an oil tanker in the Channel of Sicily. In mid-2009, maintenance operations of the damaged line were still ongoing.

As for Hungary, the gas shortage scenario assumes an interruption of supply from the Beregovo pipeline from the Ukraine, which has a capacity of 11 bcm per year. The interruption is assumed for a period of 5 months, just like the aforementioned Italian shortage.

3.2 STEP 2: impact assessment

The monthly balance between gas supply (storage included) and demand in Italy and in Hungary in the reference year 2015 has been estimated, in order to calculate the amount of gas available for power generation in case the gas supply shortage occurs.
In the Italian case, we assumed:

- a progressive reduction of gas national production,
- the availability of the new *IGI Poseidon* pipeline (8 bcm/year) allowing Italy and the rest of Europe to import natural gas from the Caspian Sea and the Middle East,
- the availability of the new LNG terminal in Livorno (3.75 bcm/year),
- the use of all gas storage capacity for modulation service,
- a recovery of industrial gas consumption to the pre-economic crisis levels,
- gas consumption on distribution networks corresponding to the heating demand in a cold winter whose probability to occur is once every 20 years.

The results are shown in the following Table 4.

		November	December	January	February	March
SUPPLY	National production	0.11	0.11	0.11	0.11	0.11
	Import pipelines	6.34	6.34	6.34	6.34	6.34
	LNG terminals	1.21	1.21	1.21	1.21	1.21
	Storage	0.95	2.01	2.94	2.34	0.47
	TOTAL	8.61	9.67	10.60	10.00	8.13
DEMAND	Distribution networks	-4.57	-6.30	-6.68	-5.47	-4.49
	Industry	-1.7	-1.7	-1.7	-1.7	-1.7
	Network consumptions and losses	-0.13	-0.13	-0.13	-0.13	-0.13
	TOTAL	-6.40	-8.12	-8.51	-7.29	-6.32
Gas available for power generation		2.21	1.54	2.09	2.71	1.82

Table 4: Monthly amount of gas available for power generation in the considered Italian shortage scenario (bcm).

As for Hungary, which is expected to add in 2010 new gas storage with a capacity of approximately 1.9 bcm, of which 1.2 bcm is reserved for strategic purposes, the demand / supply balance (without resorting to strategic storage) shows that gas available for power generation in the considered shortage scenario is very little, i.e. about **0.079 bcm/month**.

3.3 STEP 3: assessment of EU vulnerability to energy risks

In order to assess the vulnerability of the European power system to a gas supply shortage, it is interesting to take into account the share of gas-fired production over the whole electricity production in each country. In the following Table 5 data provided by Eurostat for year 2007 are reported.

Country	Electricity production [GWh]	Gas-fired electricity production [GWh]	%
Luxembourg	4001	2895	**72.4**
The Netherlands	103241	59038	**57.2**
Italy	313887	172646	**55.0**
Ireland	28226	15463	**54.8**
Turkey	191558	95025	**49.6**
United Kingdom	396143	164474	**41.5**
Latvia	4771	1924	**40.3**
Hungary	39959	15232	**38.1**
Spain	303293	92509	**30.5**
Belgium	88820	25384	**28.6**
Portugal	47253	13124	**27.8**
Croatia	12245	3064	**25.0**
Greece	63497	13774	**21.7**
Romania	61673	11559	**18.7**
Denmark	39154	6912	**17.7**
Lithuania	14007	2405	**17.2**
Austria	63430	9871	**15.6**
Finland	81249	10544	**13.0**
Germany	637101	73342	**11.5**
Slovakia	28056	1617	**5.8**
Bulgaria	43297	2336	**5.4**
Estonia	12190	590	**4.8**
France	569841	21987	**3.9**
Czech Republic	88198	3175	**3.6**
Slovenia	15043	453	**3.0**
Poland	159348	3062	**1.9**
Switzerland	67950	750	**1.1**
Norway	137471	730	**0.5**
Sweden	148849	781	**0.5**
Cyprus	4871	0	**0.0**
Malta	2296	0	**0.0**

Table 5: Share of gas-fired electricity production in 2007 in the European countries (source: Eurostat).

It can be seen that Hungary, Latvia, United Kingdom, Turkey, Ireland, Italy, the Netherlands and Luxembourg have quite relevant gas-fired production shares, ranging from about 40% to more than 70%.

In any case, in terms of security of supply, what is important is the share of gas-fired generation on the available overall generation capacity. Moreover, also import capacity must be taken into account as a possible substitute for gas-fired generation.

To assess the vulnerability of the power system of the different European countries to gas supply shortages, we took into account the winter peak load value of year 2008, including grid losses.

As for gas shortage, we assumed a severe and long-lasting one, so that no gas is available for power generation (both CHP and non-CHP), even from storage facilities, at peak load time.

As for thermal power plants fired with fossil fuels other than gas, we assumed that they can operate at their maximum nominal power. Moreover, we assumed that gas-fired conventional steam turbine power plants can switch from gas to fuel-oil.

As for reservoir and pumped storage hydro power plants, their power generated at peak load time has been estimated on the basis of their production in the corresponding month.

As for the remaining power plants, which include both run-of-river hydro and the other Renewable Energy Sources, their power generated at peak load time has been estimated on the basis of their production in the corresponding month, assuming a flat generation profile.

Finally, regarding cross-border interconnections, it has been assumed that during the gas shortage the concerned country can import as much as possible from all its neighboring countries, according to the NTC (Net Transfer Capacity) values.

In the following Table 6 the results of the analysis are reported, highlighting in red the critical values of available power lower than peak load. In addition to EU countries, other interconnected countries (or aggregate of countries) taken into account in the model of the European power system developed for the study have been considered.

According to the assumptions made above, on the basis of this analysis, the considered countries can be divided into three different categories:

- countries that, in case of such a severe gas supply shortage, cannot meet peak load, even with the help of other neighboring countries: Greece, Spain, the Netherlands and United Kingdom;
- countries that could deal with such an emergency, but only with the help of other neighboring countries (provided that they are not affected by the same gas shortage): Austria, Belgium and Luxembourg, Italy, Latvia, Slovak Republic and Switzerland;
- countries that, according to this rough analysis (that, as above mentioned, does not take into account the requirements of heat demand supplied by CHP gas-fired plants and takes for granted the possibility of saturating import capacity), can meet peak load with their own remaining generation resources.

Country	2008 winter peak load			Available power [MW]		
	Day	Hour	Value [MW]	Generation	Import	Generation plus import
Austria	26 Nov	18:00	9374	**9367**	4985	14352
Balkan countries	31 Dec	18:00	13607	14624	3160	17784
Belgium & Luxembourg	14 Feb	19:00	14518	**13609**	6580	20189
Bulgaria	13 Jan	19:00	7034	8893	1550	10443
Croatia	31 Dec	18:00	3009	3126	2920	6046
Czech Republic	14 Feb	15:00	10010	13743	4150	17893
Denmark	3 Jan	18:00	6408	8302	4430	12732
Estonia	7 Jan	17:00	1479	2101	2100	4201
Finland	4 Jan	17:00	13770	14913	3800	18713
France	15 Dec	19:00	84730	99658	10745	110403
Germany	15 Jan	19:00	76763	92382	16900	109282
Greece	31 Dec	18:00	9010	**6833**	1100	**7933**
Hungary	9 Jan	17:00	6473	6813	4300	11113
Ireland	17 Dec	17:00	4900	6231	200	6431
Italy	23 Jan	18:00	53194	**50925**	8040	58965
Latvia	7 Jan	18:00	1419	**489**	2650	3139
Lithuania	7 Jan	18:00	1843	3970	3380	7350
Poland	4 Jan	18:00	23115	30301	3540	33841
Portugal	2 Dec	21:00	8961	9834	1300	11134
Romania	10 Jan	18:00	8589	12853	2450	15303
Slovak Republic	9 Jan	18:00	4342	**4111**	2500	6611
Slovenia	9 Jan	18:00	1963	2441	1710	4151
Spain	15 Dec	19:00	42920	**37503**	3200	**40703**
Sweden	23 Jan	17:00	24500	26556	6990	33546
Switzerland	28 Nov	11:00	8132	**7651**	6980	14631
The Netherlands	15 Jan	18:00	18465	**7718**	6950	**14668**
Ukraine West	5 Jan	17:00	1047	2528	1100	3628
United Kingdom	3 Jan	17:00	58207	**47812**	2068	**49880**

Table 6: Assessment of the vulnerability of the power systems of European countries to severe gas supply shortages (values of available power lower than peak load reported in red).

3.4 STEP 4: cost assessment

The impact and cost quantitative assessment of the gas supply shortages taken into account have been focused on the following main aspects:

- security of supply (i.e. electric energy not supplied);
- competitiveness (i.e. electricity production costs);
- sustainability (i.e. CO_2 emissions).

The assessment has been carried out by developing and running a model of the European power system, based on the MTSIM simulator, developed by ERSE.
MTSIM (*Medium Term SIMulator*), is a zonal electricity market simulator able to calculate the:

- hourly marginal price for each market zone;
- hourly dispatching of all dispatchable power plants;
- fuel consumption and related cost for each thermal power plant;
- emissions of CO_2 (and of other pollutants) and related costs for emission allowances;
- power flows on the interconnections between market zones;
- revenues, variable profits and market shares of the modeled generation companies.

The model can handle several types of constraints, such as the maximum allowed fuel consumption over a certain time period: this feature has been used to model the gas shortages.
In the present study, MTSIM has been used to simulate the optimal behavior of the modeled European power system, having as objective function the cost (fuel and CO_2 allowances) minimization. No market power exercise has been simulated, in order to focus on the "natural" best response of the power system to the considered gas shortages.
As for the model of the European power system, the AC transmission network has been modeled with an equivalent representation (see Figure 2[1]) where each country (or aggregate of countries, such as in the Balkans) is represented by a node (i.e. market zone), interconnected with the neighboring countries via equivalent lines characterized by a transmission capacity equal to the corresponding cross-border Net Transfer Capacity (NTC, data provided by ENTSO-E).
As far as the electricity exchanges via DC interconnections are concerned, it was decided to impose an hourly profile. The same has been done for AC interconnections with other power systems.
For all those interconnections for which market data were available, the most recent hourly profiles have been adopted, taken from the relevant electricity markets websites.
For all the other ones, the 2008 monthly exchange values (source: ENTSO-E) have been profiled according to the load profile of the importing country.
As for generation capacity, in the model each country has been "collapsed" into a node of the equivalent AC European network, therefore, for each country, an "equivalent" power plant for each main generation technology has been defined.
In general, the net generation capacity values (for each technology/fuel and for the reference year 2015), have been taken from the "Conservative Scenario" (Scenario A) of the UCTE (now ENTSO-E) *System Adequacy Forecast (SAF) 2009-2020*. Such scenario takes into account the commissioning of new power plants considered as sure and the shutdown of power plants expected during the study period.
Additional information necessary for a more detailed subdivision of the UCTE data have been taken from the results of the FP6 project ENCOURAGED and of the FP7 project REALISEGRID, as well as estimated by ERSE.

[1] In the figure, "BL" represents Belgium and Luxembourg, "BX" represents Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia and Serbia, while "DE" represents Germany and Denmark West.

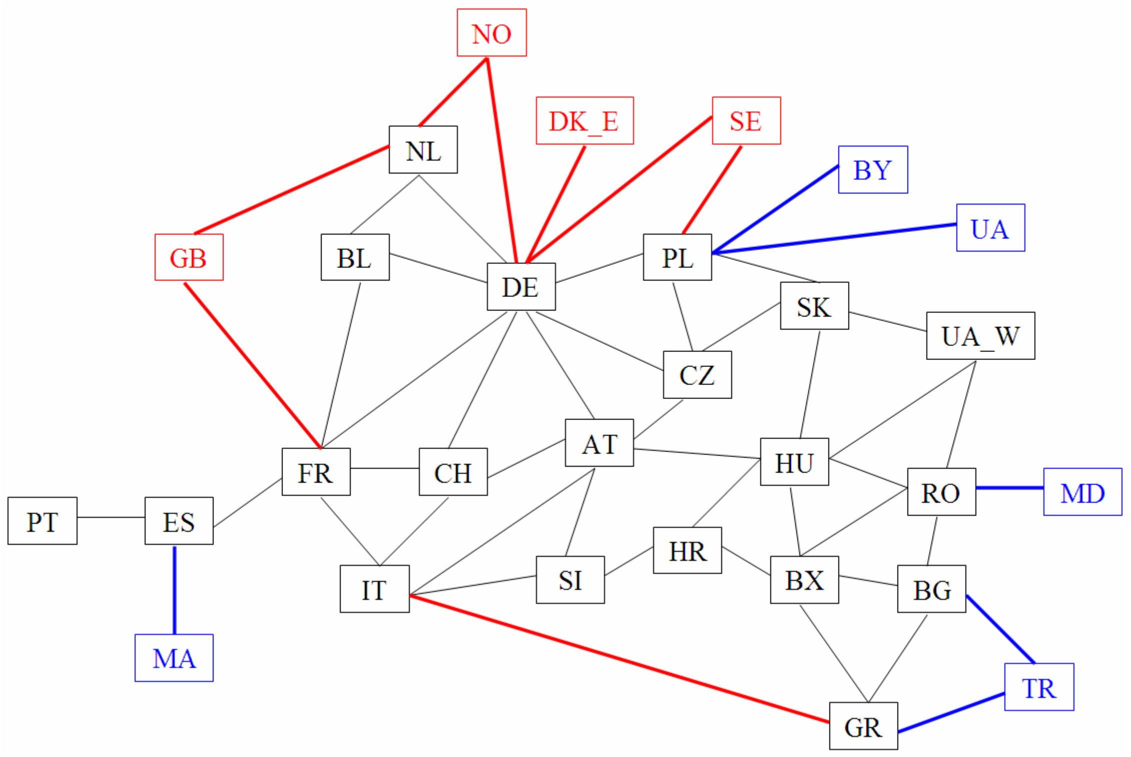

Figure 2: The model of the European power system - Cross-border AC interconnections (in black), DC interconnections (in red) and AC interconnections with other power systems (in blue).

As for the other main scenario assumptions (concerning fuel prices, CO_2 emissions value[2] and electricity demand), they have been derived from the POLES scenario *"GR-FT Global Regime with Full Trade"*.
This scenario assumes the introduction of a global cap on emissions, with abatement programs corresponding to a cost-effective program resulting from a unique carbon value, as introduced either by a global carbon market or by an international carbon tax.
In any case, it must be noted that, as far as year 2015 is concerned (that is the reference year of the present study), the various POLES scenarios[3] are quite similar: in fact, their differences become evident mainly after 2020 till 2050, i.e. in the second part of the considered time horizon.

For both the Italian and the Hungarian shortage scenarios, two simulations have been carried out, in which the modeled European power system has been dispatched to cover the load foreseen for the reference year 2015:

- the "base case", without any gas shortage,
- the "shortage case", with the assumed gas supply shortage.

Then, the results of the simulations of the two cases have been compared in order to draw conclusions, as reported in the following (all the reported data refer to the five months November ÷ March, when the gas supply shortage occurs).

[2] That is quite low, i.e. 13.25 €/tCO_2.
[3] In addition to GR-FT, there are two other POLES scenarios: MT – *Muddling Through* and EA- *Europe Alone* (see paragraph 4.4).

As for the Italian shortage, in the following Table 7, a comparison between gas consumption for power generation in the "base case" and the estimated amount of available gas (see Table 4) without resorting to strategic storage is reported.

	November	December	January	February	March	Nov÷Mar
Gas available for power generation	**2.21**	**1.54**	**2.09**	**2.71**	**1.82**	**10.37**
Consumption of CHP power plants	**-1.58**	**-1.63**	**-1.63**	**-1.48**	**-1.60**	**-7.92**
Consumption of non-CHP power plants	**-1.04**	**-1.13**	**-1.58**	**-1.83**	**-1.17**	**-6.75**
Balance	**-0.41**	**-1.22**	**-1.12**	**-0.6**	**-0.95**	**-4.3**

Table 7: Comparison between gas consumption for power generation in the "base case" and the estimated amount of available gas, without resorting to strategic storage (bcm).

It is quite clear that there is no gas enough to allow for a "normal" operation of the Italian generation system, that would require an additional consumption of about **4.3 bcm** out of the 5.17 bcm strategic storage capacity. Moreover, it must be taken into account that the more strategic storage is depleted, the less the daily peak flowrate of the extracted gas, so that, in case of cold days in the last part of the winter, supply can be at risk even if gas reserves are not exhausted.

As for the "shortage case", we impose the amount of gas available for power generation (see Table 4) as a constraint to the MTSIM simulator.
In such a case, the modeled European power system is redispatched to provide more energy to Italy, in order to compensate for its reduced generation. Moreover, in Italy the available fuel oil-fired generation capacity is dispatched to face the gas shortage.
Finally, a constant import of 500 MW (the NTC value) from the Italy-Greece DC interconnector is assumed.
Under these conditions and assuming not to use the strategic gas storage for non-CHP thermal power plants[4], a criticality shows up only in December (the month with the greatest lack of gas: see Table 7), when the modeled power system is not able to supply **349.5 GWh**, i.e. about 1.38% of the monthly load.
Assuming to produce such energy with a Combined Cycle Gas Turbine power plant with a 55% efficiency, it would correspond to a gas consumption of about **66 Mcm**, that could be easily provided by the strategic storage.
Moreover, it can be seen that the neighboring generation systems do their best to help Italy to tackle the shortage: in fact, when there is energy not supplied in Italy, import capacity from Austria, Slovenia and Greece is saturated, while thermoelectric generation in France and in Switzerland is at its maximum capacity. It is basically not possible to increase imports through France and Switzerland from other countries due to saturation of other relevant cross-border interconnections.

[4] **92 Mcm** of strategic gas storage are necessary in December to keep all CHP gas-fired power plants in operation.

In the following Table 8 a comparison between production by different fuels of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" is reported.
Overall, the fuel substitution by fuel-oil (that occurs in Italy) appears evident (see also Table 9). It can also been noticed a somewhat unexpected decrease of hard coal production, that the simulator performs to accommodate the greater energy flows towards Italy, taking into account the constraints of the meshed cross-border transmission network. The dependency of such phenomenon from network flows appears clear looking at the results of the "unconstrained shortage case" (see in the following), where, removing any network constraint, generation of hard coal-fired power plants significantly increases.

Fuel	"base case" [GWh]	"shortage case" [GWh]	Δ%
Nuclear	317341	317177	-0.1
Hard coal	189231	185315	-2.1
Lignite	111115	110744	-0.3
Natural gas	138275	132080	-4.5
Fuel oil	218	10510	4722.6

Table 8: Comparison between production by different fuels of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" (GWh).

Fuel	"base case" [PJ]	"shortage case" [PJ]	Δ%
Nuclear	3298.46	3296.70	-0.1
Hard coal	1947.94	1905.39	-2.2
Lignite	1147.58	1143.76	-0.3
Natural gas	900.15	877.72	-2.5
Fuel oil	2.18	100.18	4495.4

Table 9: Comparison between fuel consumption of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" (PJ).

Of course, in the "shortage case" CO_2 emissions of the Italian power system decrease (by 1946 ktCO_2), due to the reduced production of its power plants caused by the gas supply shortage.
Anyway, due to substitution of gas generation with less efficient and more emissive fuel-oil power plants, CO_2 emissions decrease much less (-5.6%) than power generation (-20.9%).
As for the entire modeled European power system, the difference is significant: CO_2 emissions of the non-CHP power plants in the "shortage case" are 355367 ktCO_2, that is **1904 ktCO_2** greater than the "base case" (353463 ktCO_2).

As for the cost assessment, as above mentioned, if we make the (unrealistic) assumption not to use in any case strategic storage for non-CHP thermal power plants operation, about 349.5 GWh of energy would not be supplied in December. With a 20 €/kWh VOLL, this would entail the astronomical cost of about 7 billions €.
If, on the contrary, we assume to use a very small part (66 Mcm) of strategic gas storage to avoid such energy not supplied, the extra-costs that the modeled European power system must bear due to the Italian gas shortage are basically due only to the change of fuel mix and to the increase of CO_2 emissions and of the related need for allowances.
As reported in Table 10, the resulting total extra-cost is quite high, being around **646 M€**.

	Extra-costs [M€]
Change of fuel mix	619
Increased CO_2 emissions	27
Total	**646**

Table 10: Extra-costs borne by the modeled power system due to the gas shortage in Italy.

As for the Hungarian shortage, In the following Table 11, a comparison between gas consumption for power generation in the "base case" and the estimated amount of available gas (see paragraph 3.2) without resorting to strategic storage is reported.

	November	December	January	February	March	Nov÷Mar
Gas available for power generation	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.395**
Consumption of CHP power plants	**-0.207**	**-0.207**	**-0.207**	**-0.207**	**-0.207**	**-1.035**
Consumption of non-CHP power plants	**-0.016**	**-0.013**	**-0.045**	**-0.085**	**-0.006**	**-0.165**
Balance	**-0.144**	**-0.141**	**-0.173**	**-0.213**	**-0.134**	**-0.805**

Table 11: Comparison between gas consumption for power generation in the "base case" and the estimated amount of available gas, without resorting to strategic storage (bcm).

It is quite clear that there is no gas enough to allow for a "normal" operation of the Hungarian generation system, that would require an additional consumption of about **0.8 bcm** out of the 1.2 bcm strategic storage capacity.

As for the "shortage case", we impose the amount of gas available for power generation as a constraint to the MTSIM simulator, but we also assume that CHP power plants operate like in the "base case" to supply their heat demand, using gas coming from strategic reserves for an amount of **0.64 bcm**.

In such a case, the modeled European power system is redispatched to provide more energy to Hungary, in order to compensate for its reduced generation.
Under these conditions and assuming not to use the strategic gas storage for non-CHP thermal power plants, no criticality occurs in terms of energy not supplied.
Moreover, it can be seen that the neighboring generation systems do their best to help Hungary providing it with more energy.
In the following Table 12 a comparison between production by different fuels of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" is reported.
Overall, the differences between the two cases are quite small, also as far as fuel consumption is concerned (see Table 13).

Fuel	"base case" [GWh]	"shortage case" [GWh]	Δ%
Nuclear	317341	317341	0.0
Hard coal	189231	189396	0.1
Lignite	111115	111112	0.0
Natural gas	138275	138051	-0.2
Fuel oil	218	278	27.7

Table 12: Comparison between production by different fuels of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" (GWh).

Fuel	"base case" [PJ]	"shortage case" [PJ]	Δ%
Nuclear	3298.46	3298.46	0.0
Hard coal	1947.94	1949.68	0.1
Lignite	1147.58	1147.56	0.0
Natural gas	900.15	899.98	0.0
Fuel oil	2.18	2.77	27.1

Table 13: Comparison between fuel consumption of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" (PJ).

Of course, in the "shortage case" CO_2 emissions of the Hungarian power system decrease (by 306 ktCO_2), due to the reduced production of its power plants caused by the gas supply shortage.
As for the entire modeled European power system, just like for fuel consumption, the difference is quite small: CO_2 emissions of non-CHP power plants in the "shortage case" are 353661 ktCO_2, that is **198 ktCO_2** greater than the "base case" (353463 ktCO_2).

As for the cost assessment, the extra-costs that the modeled European power system must bear due to the Hungarian gas shortage are basically due to the change of fuel mix and to the increase of CO_2 emissions and of the related need for allowances.

As reported in Table 14, the total extra-cost is quite limited, being around **10 M€**.

	Extra-costs [M€]
Change of fuel mix	7.42
Increased CO_2 emissions	2.63
Total	**10.05**

Table 14: Extra-costs borne by the modeled power system due to the gas shortage in Hungary.

3.5 STEP 5: remedies assessment

Remedies to tackle the impact of gas supply shortages on electricity security of supply can be put in practice both in the short and in the long term, and they can affect both the gas and the electricity sector.

3.5.1 Short-term remedies in the gas sector

- *Maximize imports from the remaining supply sources*

The most natural remedy to tackle (at least partially) the failure of a supply source is, of course, to maximize imports from the remaining sources. Typically, pipelines and LNG terminals are not used at their maximum capacity, so that a certain margin to increase imports remains available.

- *Use gas storage*

The availability of a significant amount of gas storage, both for modulation and, especially, for strategic purposes, is the best insurance against a gas shortage in the short term, as shown above.
Nevertheless, it must be taken into account that the more strategic storage is depleted, the less the daily peak flowrate of the extracted gas, so that, in case of cold days in the last part of the winter, supply can be at risk even if gas reserves are not exhausted.

- *Reduce demand*

In order to reduce gas demand in case of shortage, it is possible to resort to interruptible contracts, typically with industrial consumers that have fuel switching capabilities in their production processes.
Moreover, it is possible to set up information campaigns or regulations aimed at limiting the temperature of residential and tertiary space heating.

As an example, all of the above actions (import maximization, use of strategic storage and demand reduction) were put in practice in Italy during the cold 2005/2006 winter.

3.5.2 Long-term remedies in the gas sector

- *Diversify supply sources*

In the longer term, one of the best ways to reduce the risk of shortage is to diversify supply sources, that means to diversify not only suppliers but also supply infrastructures.
In particular, LNG terminals are the most flexible way to implement diversification.
Moreover, the diversification of supply infrastructures, for example in case of new pipelines with different paths, can reduce the risk of shortages caused by transit countries.

- *Increase gas storage capacity*

As above mentioned, once a shortage takes place, the availability of a significant amount of gas storage, both for modulation and, especially, for strategic purposes, is the best insurance for all gas consumers.

- *Increase energy efficiency in gas consumption*

There is a good margin for reducing gas demand by increasing energy efficiency in end uses, especially as far as space heating is concerned in the residential and in the tertiary sectors.
To this aim, European directives (such as Directive 2002/91/EC of 16 December 2002 on the energy performance of buildings, Directive 2005/32/EC of 6 July 2005 establishing a framework for the setting of ecodesign requirements for energy-using products and amending Council Directive 92/42/EEC and Directives 96/57/EC and 2000/55/EC, Directive 2006/32/EC of 5 April 2006 on energy end-use efficiency and energy services and repealing Council Directive 93/76/EEC, etc.) and national laws and regulations have been issued and are being implemented.
Additional increase of efficiency in gas consumption could be achieved by a further development of CHP plants, according to Directive 2004/8/EC of 11 February 2004 on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC.

- *Develop Renewable Energy Sources*

Renewable Energy Sources (whose development is supported at the EU level by the Directive 2009/28/EC on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC), such as solar thermal, biomass and geothermal, can effectively substitute gas for heating applications, thus reducing its demand.

3.5.3 Short-term remedies in the electricity sector

- *Perform fuel switching*

If generation capacity fired with fuels other than gas is available, it can be dispatched in order to substitute gas-fired generation. The problem is that such kind of reserve is typically made of costly and inefficient power plants, such as fuel-oil fired steam turbines or even gasoil fired open cycle gas turbines, therefore fuel switching is a quite expensive remedy, both in terms of extra fuel costs and in terms of extra CO_2 emissions costs (see for example the 640 M€ of extra costs reported in paragraph 3.4 for the Italian gas shortage scenario).
In principle, also reservoir hydro generation could be increased to substitute gas-fired generation, but in case of long-lasting shortages this kind of remedy is hardly viable.

- *Increase electricity imports*

Of course, gas-fired generation can be substituted also by additional imports from neighboring countries, provided that import capacity is not saturated and that the foreign generation systems can produce the required additional energy. This remedy, generally speaking, is more efficient than fuel switching both from the economic and from the environmental points of view.

- *Reduce demand*

Just like in the gas sector, in case of necessity contracts for interruptible loads can be activated to reduce electricity demand.
Moreover, where implemented, *Demand Side Management* programs can help reducing peak loads (for example with *Critical Peak Pricing* schemes) and the related stress on the power generation system.

3.5.4 Long-term remedies in the electricity sector

- *Diversify generation sources*

As for gas supply sources, a diversification of electricity generation sources is highly desirable to reduce security of supply risks.
A further development of Renewable Energy Sources, supported by the aforementioned Directive 2009/28/EC, is a must not only for security of supply, but also for several other reasons.
In countries where the share of gas-fired generation capacity is quite high (such as in Italy), a further development of coal-fired and of nuclear power plants could be desirable from the diversification point of view, notwithstanding the high CO_2 emission rates of the former (possibly tackled in the future by *CCS – Carbon Capture and Storage* technologies) and the problems of social acceptability and of waste management of the latter.
In any case, it must be taken into account that RES on one side and coal and nuclear on the other side, are not perfect substitutes of gas-fired generation technologies.

In fact, the former are in most cases non dispatchable and affected by a significant volatility, while the latter are base-load technologies, characterized by a lower degree of flexibility than gas-fired ones, such as CCGTs.
This means that the diversification process must in any case aim at obtaining a well balanced and well adapted to the load generation set.

- *Increase cross-border transmission capacity*

The reduction of bottlenecks in the European transmission network, especially the ones affecting cross-border trades, would make easier to transport energy where it is required, increasing security of supply, but also allowing for a more optimized operation of the generation set, with significant economic benefits.
This subject has been analyzed in more detail in [3] (see also chapter 4), nevertheless a simple simulation can be done with the model of the European power system we developed for the present study.
In particular, we can compare the results of the Italian "shortage case" with a purely theoretical ideal scenario (that we will call "unconstrained shortage case") where all cross-border AC transmission capacity constraints are removed, in order to assess their strength in constraining the system. In the following, the results concerning the five cold months when the shortage occurs in the two cases are reported.

First of all, in the "unconstrained shortage case" no energy not supplied in Italy occurs, since electricity imports from the northern frontier increase by 72% (see Table 15).

Interconnection	"shortage case" [GWh]	"unconstrained" [GWh]	∆%
FR ⇨ IT	7203	13431	86
CH ⇨ IT	5671	8237	45
AT ⇨ IT	712	1317	85
SI ⇨ IT	1951	3750	92
Total	**15537**	**26736**	**72**

Table 15: Increase of electricity imports from the northern frontier in the "unconstrained shortage case" w.r.t. the "shortage case" (GWh).

Moreover, such greater availability of "foreign" energy allows not to dispatch Italian fuel oil-fired power plants; in addition, a significant increase at the European level of cheaper coal production (due to the low CO_2 emissions value of 13.25 €/t assumed in the POLES GR-FT scenario taken as a reference) substitutes not only fuel oil-fired, but also gas-fired generation, as shown in Table 16. The corresponding results in terms of fuel consumptions are shown in Table 17.

Fuel	"shortage case" [GWh]	"unconstrained" [GWh]	∆%
Nuclear	317177	317395	0.1
Hard coal	185315	199865	7.9
Lignite	110744	111577	0.8
Natural gas	132080	127345	-3.6
Fuel oil	10510	0	-100

Table 16: Comparison between productions by different fuels of non-CHP plants in the "unconstrained shortage case" w.r.t. the "shortage case" (GWh).

Fuel	"shortage case" [PJ]	"unconstrained" [PJ]	∆%
Nuclear	3296.70	3299.01	0.1
Hard coal	1905.39	2062.59	8.3
Lignite	1143.76	1152.35	0.8
Natural gas	877.72	800.11	-8.8
Fuel oil	100.18	0	-100

Table 17: Comparison between fuel consumption of non-CHP plants in the "unconstrained shortage case" w.r.t. the "shortage case" (PJ).

The increased coal production causes an increase of CO_2 emissions of about 3584 ktCO_2 in the "unconstrained shortage case".
In terms of costs, as shown in Table 18, due to a strong reduction of fuel costs, the "unconstrained shortage case" is about **900 M€** cheaper than the "shortage case", that is **254 M€** cheaper even than the "base case", where no gas shortage occurs.

	∆ costs [M€]
Change of fuel mix	-946
Increased CO_2 emissions	46
Total	**-900**

Table 18: Difference of costs between the "unconstrained shortage case" and the "shortage case" (M€).

- *Increase energy efficiency in electricity consumption*

Just like for the gas sector, a greater end use electric energy efficiency would entail a demand reduction that would decrease the criticality of a power generation shortage. EU is supporting this process with some of the Directives above mentioned and EU countries are implementing them within the framework of their National Energy Efficiency Action Plans.

Another beneficial action would be the promotion of the above mentioned Demand Side Management programs to increase demand response in case of critical situations.

3.6 STEP 6: how remedies should be financed / paid for

3.6.1 Short-term remedies in the gas sector

Import maximization and use of gas storage basically do not entail particular extra costs, since they simply substitute the gas unsupplied due to the shortage, that is not paid.
Costs related to interruptible contracts are socialized in the tariffs, since they benefit the whole system with a greater security of supply.
Temperature reduction in space heating entails a cost saving for end users, at the expense of a lower comfort.

3.6.2 Long-term remedies in the gas sector

The diversification of supply sources entails quite relevant investments in new infrastructures that, in case of new pipelines, involve also all the transit countries.
As for financing issues, typically a certain share of the investment is financed through equity provided by shareholders in proportion to their stakes in the project, while the remaining share is covered by external financing by a consortium of banks (for example, the Nord Stream project connecting Russia to Germany is said to be financed with 30% equity and 70% debt). The European Investment Bank (EIB) can be a major player in this field.
In any case, financial structures of these projects can be quite complex, resorting to different combinations of financing sources.
As for the increase of end-use energy efficiency, even if most of the actions in this field have a “negative” cost, some promotion is necessary, typically with fiscal incentives together with obligation schemes, such as White Certificates, whose costs are socialized, like incentives to support the (more expensive) development of Renewable Energy Sources.

3.6.3 Short-term remedies in the electricity sector

As above mentioned, fuel switching is an expensive remedy, whose costs are in the end borne by consumers, paying higher electricity prices or tariff components.
For example, in the cold 2005/2006 winter, to face a gas crisis the Italian government imposed “must-run” operation to fuel-oil fired power plants; the related extra costs borne by producers were then quantified and refunded through the increase of a tariff component.
As for the increase of electricity imports, extra costs are more probably lower, but they are borne by consumers as well.

As for demand reduction, costs related to interruptible contracts are socialized in the tariffs, since they benefit the whole system with a greater security of supply. On the other hand, *Demand Side Management* programs can reduce costs both for the participating consumers and for the system as a whole.

3.6.4 Long-term remedies in the electricity sector

As for the diversification of generation sources, RES development is typically supported by incentive schemes (such as Green Certificates or feed-in tariffs), whose costs are socialized.
The development of generation technologies like coal and nuclear requires, especially for the latter, relevant investments.
The typical debt/equity ratio for financing the construction of a conventional thermal power plant is 75-80% / 20-25%. In case of a nuclear power plant, in absence of state guarantees the investment could be much riskier, therefore requiring a higher equity share.
Within this context, an interesting case study is the construction of the new EPR nuclear power plant at Olkiluoto (Finland), where the company (TVO) that invested and will operate the plant strongly reduced financial risks by signing long-term contracts with its shareholders to sell them at production cost all the energy that will be produced by the plant. This allowed for a debt/equity ratio of 80% / 20%, with a debt interest rate of 5% and a debt duration of 40 years.
As for the increase of cross-border transmission capacity, it can be carried out by TSOs, whose investments are remunerated with a fair return through transmission tariffs, or by private investors building the so-called “merchant lines” that, due to Third Party Access exemption, are basically remunerated by electricity price differentials between the markets they interconnect.
As for increasing energy efficiency in electricity consumption, even if most of the actions in this field have a “negative” cost, some promotion is necessary, typically with fiscal incentives together with obligation schemes, such as White Certificates, whose costs are socialized.

3.7 Conclusions

This study quantified the impact on the overall European power system of possible gas supply shortages occurring in two countries whose power generation is largely based on natural gas, namely Italy and Hungary. The reference year considered for the shortage scenarios is 2015.
The impact assessment, carried out using a simulation model of the European power system, has been focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO_2 emissions) deriving from the redispatching of power generation (with possible fuel substitution) necessary to face the gas shortage, taking into account cross-border electricity exchanges.
The results for Italy showed that a limited use of strategic gas storage can avoid electric energy not supplied; moreover, the assumption of preserving as much as possible the rest of strategic gas storage proved to be quite expensive, since the fuel switching towards fuel oil causes both an increase of CO_2 emissions and, especially, a significant cost increase of about 646 M€.
The results for Hungary showed that a significant use of strategic gas storage is necessary to keep CHP plants in operation. Provided that this is done, the cost increase to face the assumed shortage is limited, being about 10 M€.
Several remedies can be envisaged to tackle the impact of gas supply shortages on electricity security of supply, that can be put in practice both in the short and in the long term, and that can affect both the gas and the electricity sector.
As for the gas sector, in a long term view, the most effective remedies are the diversification of supply sources, both in terms of suppliers and of supply infrastructures, and the increase of gas storage capacity.
As for the electricity sector, the most effective long-term remedies are the diversification of generation sources, as well as the development of the transmission network to increase transfer capacity.
Moreover, for both the gas and the electricity sectors, an increase of energy efficiency in end-uses, by reducing demand, can mitigate the effects of an unforeseen gas supply shortage.

4 Optimisation of transmission infrastructure investments in the EU power sector

This study is aimed to assess the impact of a non-optimal development of the European cross-border electricity transmission network (see [3] for additional details).
The assessment has been carried out by developing and running a model of the European power system (based on the MTSIM simulator, developed by ERSE) and is focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO_2 emissions).
In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal developments determined by MTSIM. The reference years considered in the study are 2015 and 2030.
The reference framework within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security: *Muddling Through (MT), Europe Alone (EA)* and *Global Regime with Full Trade (GR-FT).*
In the following, the results of the study will be reported according to the six-steps methodology defined within the SECURE project.

4.1 STEP 1: threat identification and assessment

The threat taken into account in this study is a non-optimal development of the European cross-border electricity transmission network.
Indeed, this is currently not a threat but a fact. Cross-border interconnection capacity was originally developed in Europe for security reasons and for mutual support between different power systems, but, especially after the coming into force of directive 96/92/EC that liberalized the electricity sector with the aim to create a single Internal Electricity Market, cross-border trading activities became more and more important, thus requiring an increase of transmission capacity.
Unfortunately, the development of cross-border transmission network did not keep the pace with the development of demand, of generation and of the related trading needs.
In fact, even today many EU countries do not reach the minimum interconnection level agreed in the EU Council held in Barcelona in March 2002, corresponding to a transmission capacity at least equal to 10% of the installed generation capacity. Such target should have been attained by 2005.
That's why the Council of European Energy Regulators (CEER) in its 2010 work program plans to produce a *"Status Review on regional electricity interconnection management and use"*, stating that regulators aim *"to create a reliable regulatory climate for new and massive investments in the cross-border capacity that the EU needs."*
Similarly, the European Network of Transmission System Operators for Electricity (ENTSO-E), in its *"Ten year network development plan 2010-2020"* deals with the investment needs on the European power grid, highlighting the insufficiency of cross-border transmission capacity in several frontiers, both in the mid and in the long term.

So, provided that the current status of cross-border transmission infrastructures is definitely non-optimal in Europe, the probability of reaching an optimal status with future developments in the next 10÷20 years is quite low.
In fact, as ENTSO-E highlights, the completion of network projects frequently requires more than 10, and sometimes up to 20 years, when major obstacles are encountered.
Within this context, the main cause of delay are the long permitting procedures involving a multitude of different authorities, typically strongly influenced by the lack of social acceptance that characterizes such kind of projects.
As ENTSO-E states, *"cross-border lines are frequently perceived by the public as mere "transit lines" or "commercial lines" of limited or nil benefit for the local community and therefore, opposition against these lines is often stronger"*.
Moreover, since such projects involve different countries, incongruous permitting procedures can cause additional problems and consequent delays.

4.2 STEP 2: impact assessment

The non-optimal development of the European cross-border electricity transmission network, as explained in paragraph 4.1, is not a potential threat but a certainty, not only considering the current situation, but also for the next 10÷20 years.
As for the Step 2 of the SECURE methodology, the assessment of the impact of this "threat" would require to define an "optimal" level of network development, and then quantify a "sub-optimal" level to be analyzed in the further steps of the methodology.
In such a case, the definition of an "optimal" level can derive only from the cost assessment carried out in Step 4 of the methodology: please refer to paragraph 4.4 for more details on this issue.
As for the assumptions concerning the "sub-optimal" level, we took into account the cross-border network investments foreseen by ENTSO-E in its development plan, focused on interconnections which are expected to be congested in the future, as well as the TEN-E-Energy-Invest study, a European Wind Energy Association's report and the network development plan of the Italian TSO TERNA, together with estimations made by ERSE within the context of the FP7 research project REALISEGRID.
Such investments have been assessed either by each TSO individually or through bilateral grid studies, on the basis of scenario hypotheses used in the Transmission Development Plan of each TSO. Therefore, they are not the result of a Europe-wide optimization process, like the one that will be carried out in the present study.
Moreover, some of the proposed projects are quite mature (already or nearly under construction), while others are only under study and their probability of realization depends also on the considered time horizon.
It must also be taken into account that the analysis carried out in the present study takes as a reference the main assumptions deriving from the different POLES scenarios, that, in particular in terms of generation / load development, might be different from the scenario hypotheses used by the TSOs that foresaw the aforementioned cross-border network expansions.

4.3 STEP 3: assessment of EU vulnerability to energy risks

In order to assess the EU vulnerability to non-optimal development of the cross-border electricity transmission network, we calculated how loaded were the different interconnections in July and in December 2008 (peak load periods), on a monthly average.
The calculations have been done by dividing the monthly energy flows by the maximum amount of energy that could have been transmitted, corresponding to the NTC (Net Transfer Capacity) of each interconnection times the 744 hours of each month (data source: ENTSO-E).
The results are reported in Figure 3 and in Figure 4[5].
It is evident that several interconnections are highly loaded even on a monthly average: this means that congestion is likely to occur in several hours.
The fact that cross-border congestion is a significant problem in the European power system is clearly shown in Figure 5, reporting the occurrence of congestion in the different frontiers in 2006.

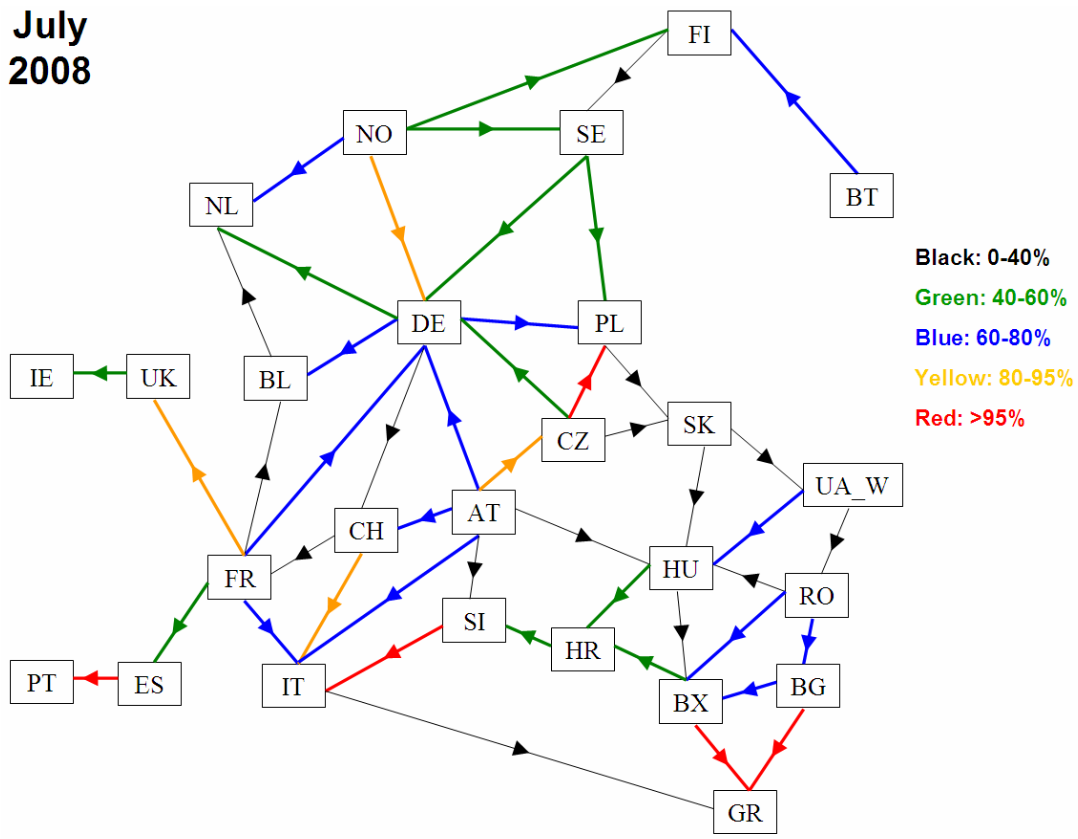

Figure 3: Average loading level of cross-border interconnections in July 2008.

5 In the figures, "BL" represents Belgium and Luxembourg, "BX" represents Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia and Serbia, "BT" represents Estonia, Latvia and Lithuania, "DE" represents Germany and Denmark West, while "SE" represents Sweden and Denmark East.

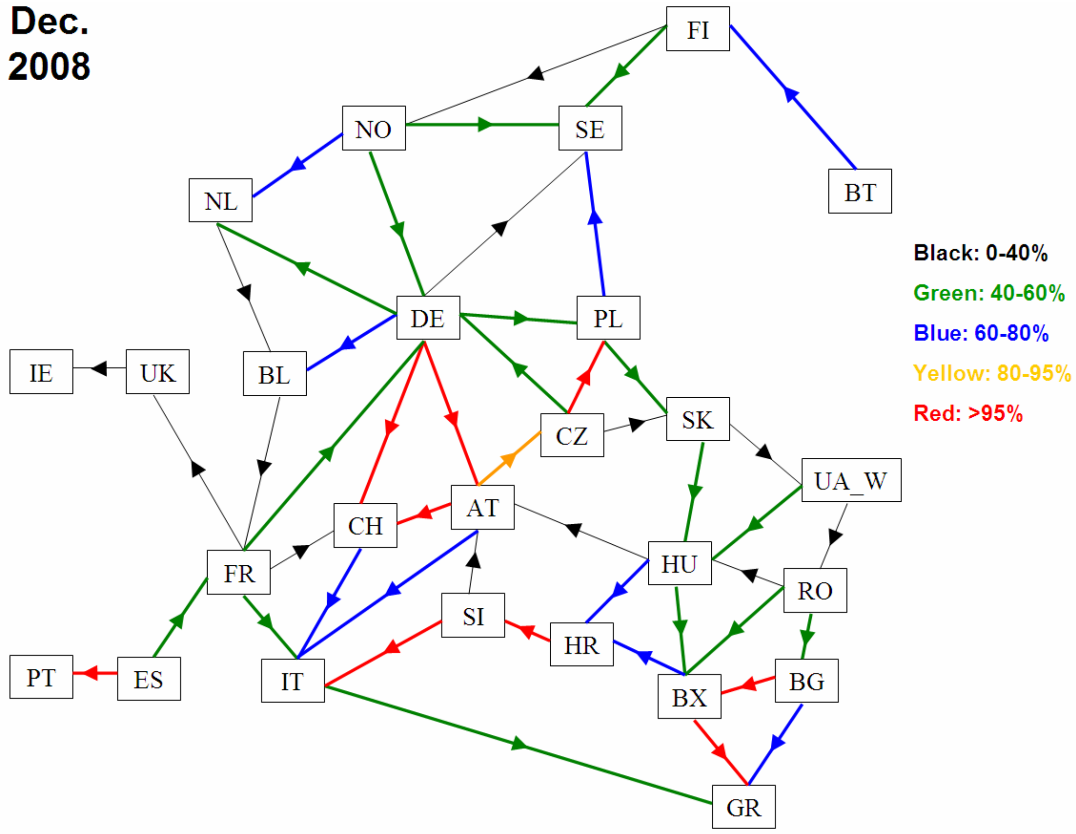

Figure 4: Average loading level of cross-border interconnections in December 2008.

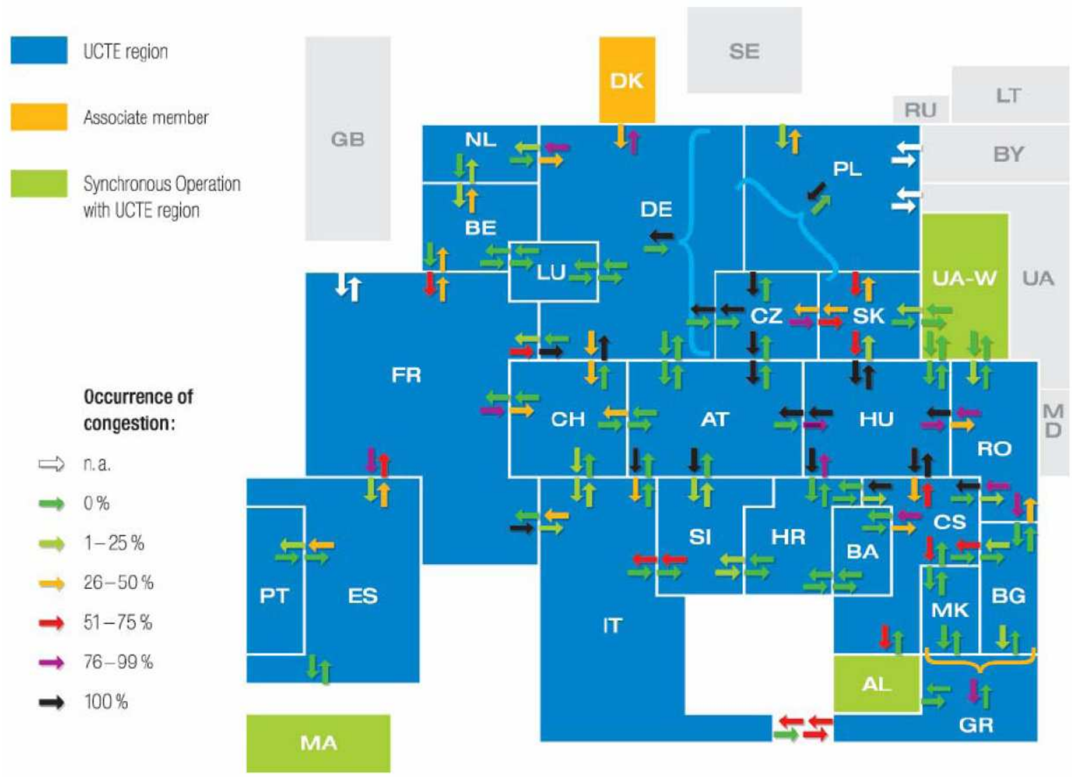

Figure 5: Occurrence of cross-border congestion in continental Europe in 2006 (source: UCTE).

4.4 STEP 4: cost assessment

The impact and cost quantitative assessment of a non-optimal development of cross-border electricity transmission network has been focused on the following main aspects:

- security of supply (i.e. possible electric energy not supplied);
- competitiveness (i.e. electricity production costs);
- sustainability (i.e. CO_2 emissions).

The assessment has been carried out by developing and running a model of the European power system, based on the MTSIM simulator, developed by ERSE (see also paragraph 3.4).
An important new feature recently implemented in the simulator is the "network expansion" capability: it can increase inter-zonal transmission capacities in case the annualized costs of such expansions are lower than the consequent reduction of generation costs due to more efficient dispatching.
In the present study, this feature has been used to determine the optimal expansion of the European AC cross-border transmission network.
As for the expansion of DC interconnectors, it has been done "manually" by selecting the most congested ones, by expanding them by a typical size (e.g. 1000 MW), and by checking that the related extra-cost is lower than the reduction of the overall system costs due to the expansion.
Thus, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs (see paragraph 4.2) with the optimal developments determined by MTSIM.
The reference framework within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security:

- *Muddling Through (MT)*: this scenario supposes a failure in the efforts to develop a common framework of targets, rules and mechanisms for climate policies; in this case only weak domestic climate policies are implemented without any element of coordination of the different actions;
- *Europe Alone (EA)*: this scenario supposes that Europe goes along a stringent climate policy line, while the rest of the world continues on the same line as the *Muddling Through*;
- *Global Regime with Full Trade (GR-FT)*: this scenario assumes the introduction of a global cap on emissions, with abatement programs corresponding to a cost-effective program resulting from a unique carbon value, as introduced either by a global carbon market or by an international carbon tax.

The reference years considered in the study are 2015 and 2030. It must be noted that, as far as year 2015 is concerned, the various POLES scenarios are quite similar: in fact, their differences become evident mainly after 2020 till 2050, i.e. in the second part of the considered time horizon. Therefore, for the reference year 2015 we will consider only the GR-FT scenario, while for year 2030 all the three POLES scenarios will be taken into account.
As for the model of the European power system, it is basically an extension to a greater number of countries of the model developed for the study reported in chapter 3, as shown in Figure 6 and in Figure 7.

In the figures, cross-border AC interconnections (in black), DC interconnections (in red) and interconnections with other power systems (in blue) are shown.
As far as the electricity exchanges via DC interconnections are concerned, differently from the study reported in chapter 3, their hourly profiles have not been exogenously imposed, but they have been determined by the MTSIM simulator, basically on the basis of the hourly electricity price differences between the zones they connect.
As for AC and DC interconnections with other power systems, hourly profiles have been imposed. In particular, for each interconnection, firstly the prevailing direction of annual net power exchanges has been envisaged. Then, the NTC value and the annual net electricity exchange have been hypothesized. Finally, this latter value has been profiled in accordance with the load profile of the importing country.

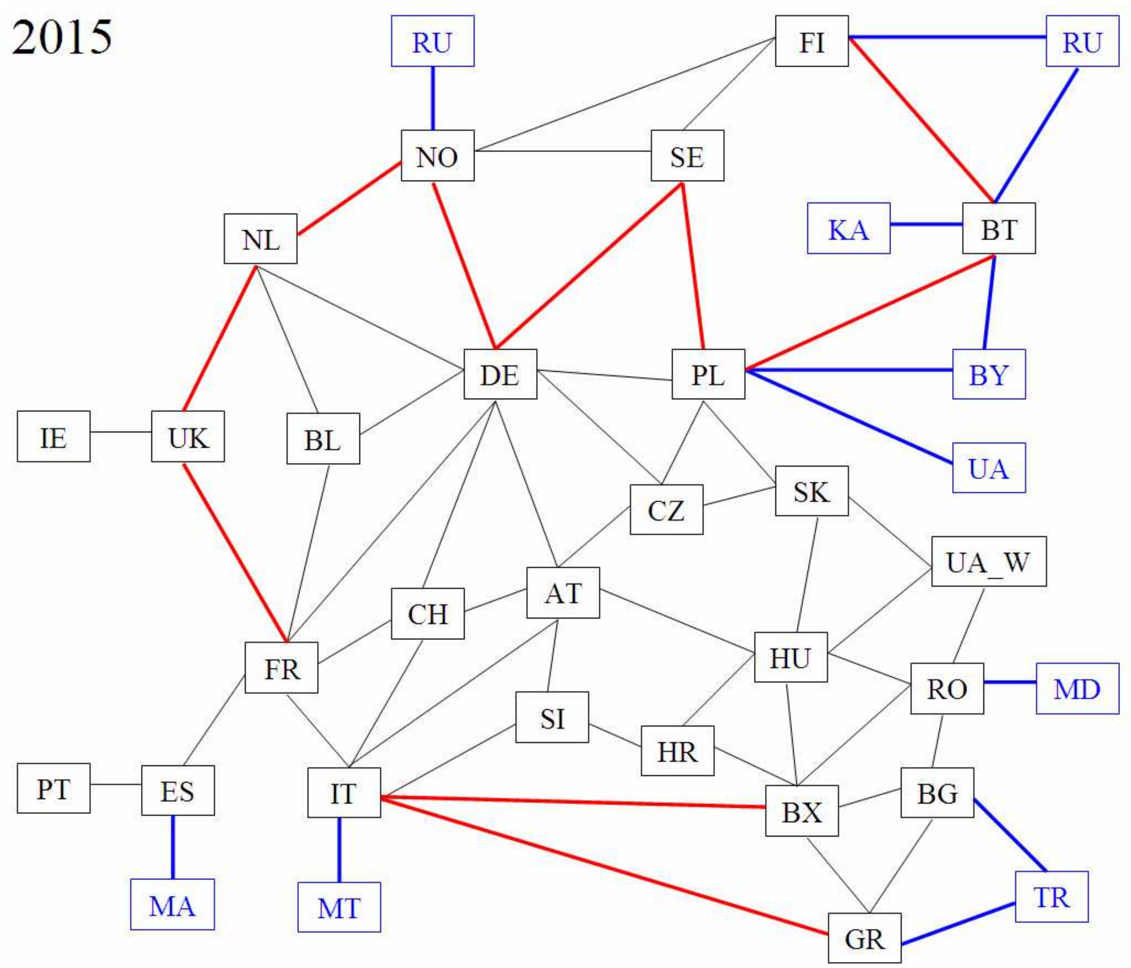

Figure 6: Equivalent representation of the European transmission network in 2015.

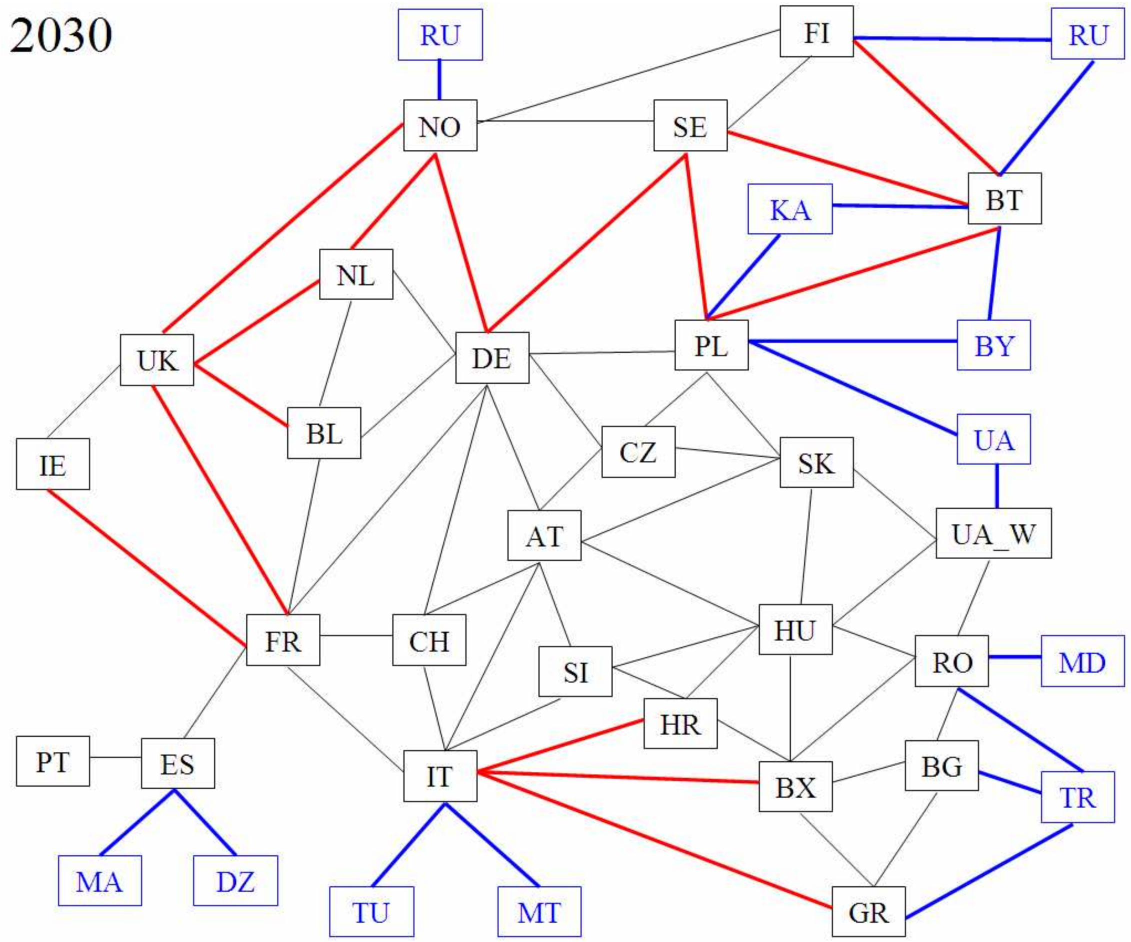

Figure 7: Equivalent representation of the European transmission network in 2030.

As for the power generation system, for the reference year 2015 the same net generation capacity values (for each technology/fuel) defined for the study reported in chapter 3 have been used, with some minor updates.

As for the countries that have been added to the model (i.e. the United Kingdom, Ireland, Norway, Sweden, Finland, Estonia, Latvia and Lithuania), the net generation capacity data have been taken from the respective Transmission System Operators' annual statistic and system adequacy reports, as well as from other available sources.

As for the reference year 2030, all generation capacity data have been derived from the results of the three POLES scenarios MT, EA and GR-FT.

As for the other main scenario assumptions (concerning fuel prices, CO_2 emissions value and electricity demand), again, they have been derived from the different POLES scenarios.

As far as network expansion is concerned, we used the average cost data considered within the context of the FP7 REALISEGRID project, based on publicly available sources and feedbacks from TSOs and from manufacturers. Of course, it must be taken into account that cost values may vary depending on different parameters, such as line length, power rating, voltage level as well as on several local factors, like manpower costs, environmental constraints, geographical conditions, etc.

As above mentioned, we compared scenarios characterized by the developments of cross-border interconnections mainly proposed by the different European TSOs (that we will call *"proposed expansion"*), with the optimal developments determined by MTSIM (that we will call *"optimal expansion"*) in the different 2015 and 2030 scenarios.
Of course, the decision to build a cross-border transmission line is based on a detailed analysis of several factors that are not taken into account in the simulations carried out in the present study, nevertheless, even if approximated, the results reported in the following can provide an interesting insight on the optimality (in terms of costs) level of the European cross-border transmission network.
In particular, in this study MTSIM has been used to simulate the optimal behavior of the modeled European power system, having as objective function the cost (fuel, CO_2 allowances and network expansion) minimization. No market power exercise has been simulated, in order to focus on the "natural" best response of the modeled power system.

As far as security of supply is concerned, the main general result of the simulations is that in no one of the considered scenarios there is Energy Not Supplied (ENS). As for the rest, in the following, for each considered scenario, we report the main results concerning:

- impact on congestion,
- impact on electricity prices,
- impact on fuel consumption,
- impact on CO_2 emissions,
- impact on costs.

4.4.1 2015 scenario

As for the impact on congestion, in Figure 8, Figure 9, Figure 10 and Figure 11 a comparison between the percentages of hours with congestion (i.e. when the power flow saturates the interconnection transmission capacity) in the different cross-border interconnections in July and in December 2015 with the "proposed expansion" and with the "optimal expansion" is reported.
In the July 2015 "optimal expansion" scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.
In the December 2015 "optimal expansion" scenario, congestion is still reduced, even if in a less significant way than in July 2015.

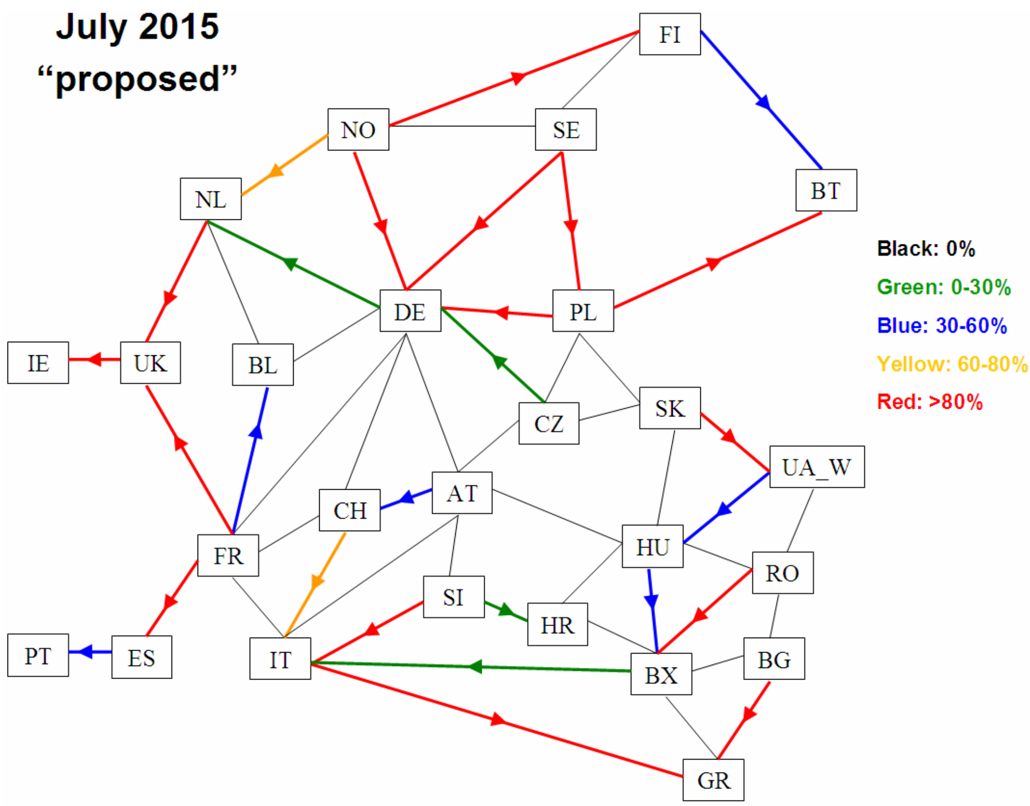

Figure 8: Percentages of hours with congestion in July 2015 with the “proposed expansion”.

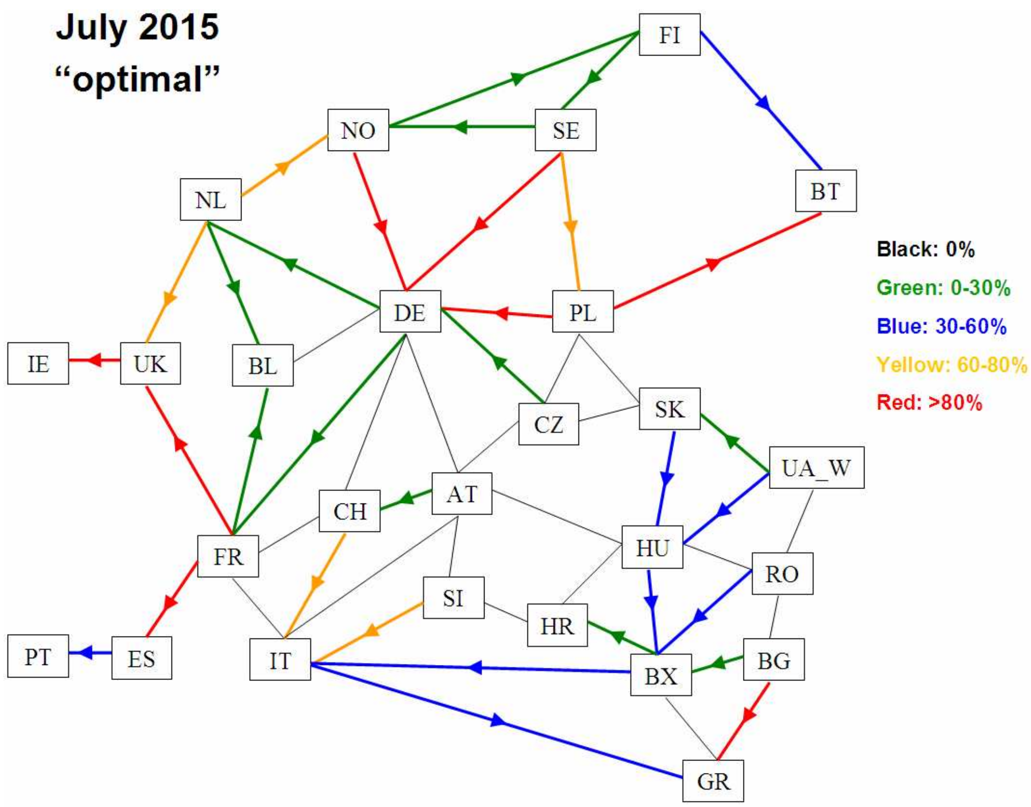

Figure 9: Percentages of hours with congestion in July 2015 with the “optimal expansion”.

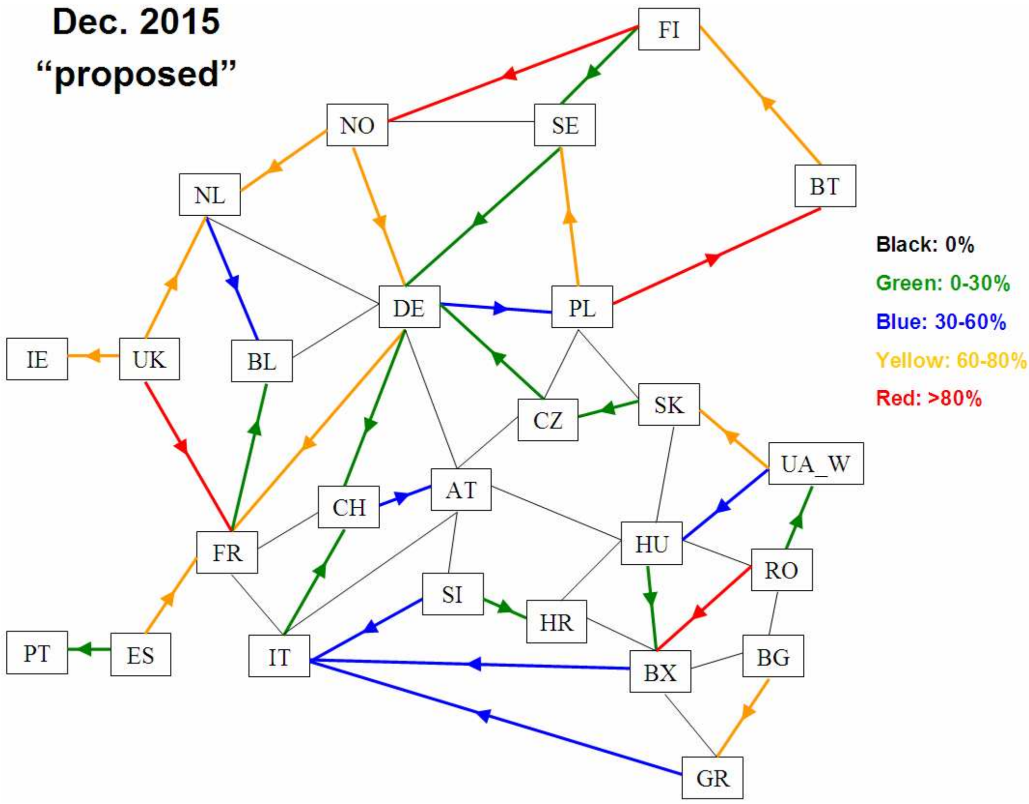

Figure 10: Percentages of hours with congestion in December 2015 with the “proposed expansion”.

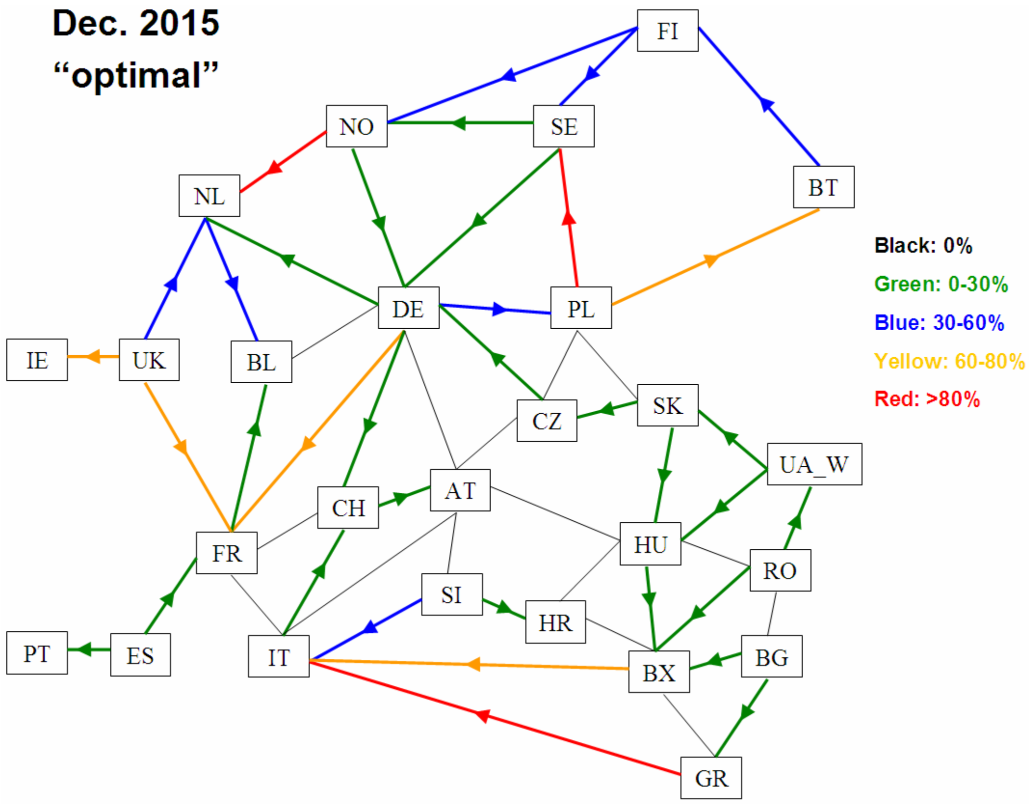

Figure 11: Percentages of hours with congestion in December 2015 with the “optimal expansion”.

As for the impact on prices, in a zonal electricity market, like the one modeled in the present study, congestion causes price differentiation between the zones. Therefore, it is interesting to see how electricity prices (or, better, marginal generation costs, in our case) vary when cross-border network is "optimally" expanded, w.r.t. the "proposed expansion" scenario.
In this way it is possible to determine "winners" and "losers", i.e. countries where the optimal expansion causes, respectively, a decrease or an increase of electricity prices.
In the following Figure 12 "winners" are shown in green, and "losers" are shown in red. The reported numerical values are the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.
It can be noted that the main "winners" in this scenario are Poland, Portugal and Spain, while the main "losers" are Sweden and Denmark East, France, Austria, Romania, Bulgaria and Slovenia.

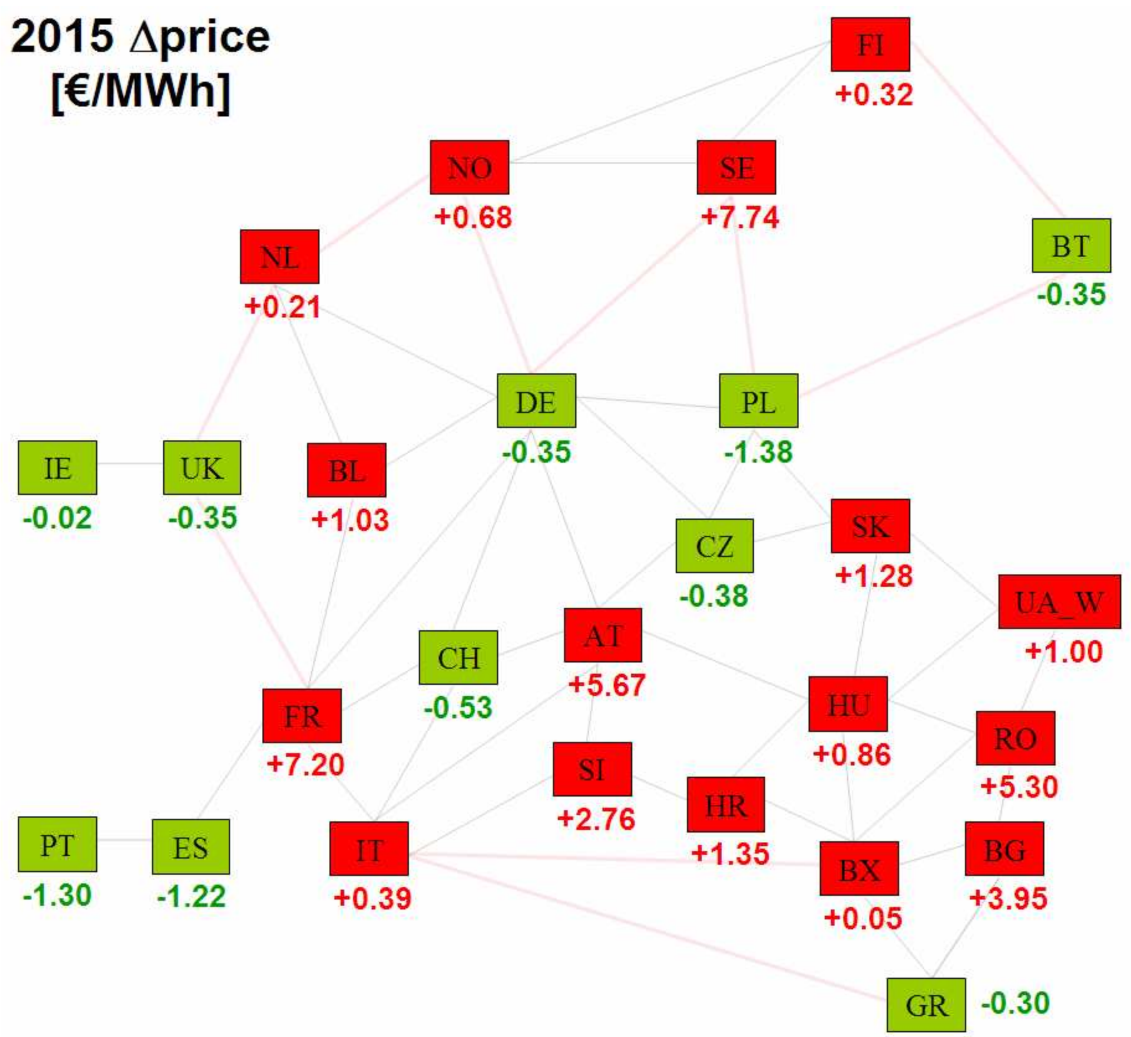

Figure 12: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2015 scenarios.

As for the impact on fuel consumption, the consequence of the "optimal expansion" (that reduces network constraints) is an increase of production by cheaper base-load power plants (nuclear, hard coal and lignite[6]) at the expense of mid-merit / peak-load natural gas fired power plants. Overall, the greater use of less efficient generation technologies slightly increases total fuel consumption.
As for the impact on CO_2 emissions, due to substitution of natural gas fired generation with less efficient and more emissive (apart from nuclear) power plants, overall CO_2 emissions slightly increase, by about **660 ktCO_2**.
As for the total costs, it can be noted that a significant reduction of fuel costs (about 600 M€) is partially compensated especially by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **335 millions of Euros**.

4.4.2 2030 "MT – Muddling Through" scenario

As for the impact on congestion, in Figure 13, Figure 14, Figure 15 and Figure 16 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the "proposed expansion" and with the "optimal expansion" is reported.
In the July 2030 "optimal expansion" scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.
In the January 2030 "optimal expansion" scenario, congestion is still reduced, even if in a less significant way than in July 2030.

[6] It must be noted that this scenario is characterized by a quite low CO_2 emissions value (13.25 €/t).

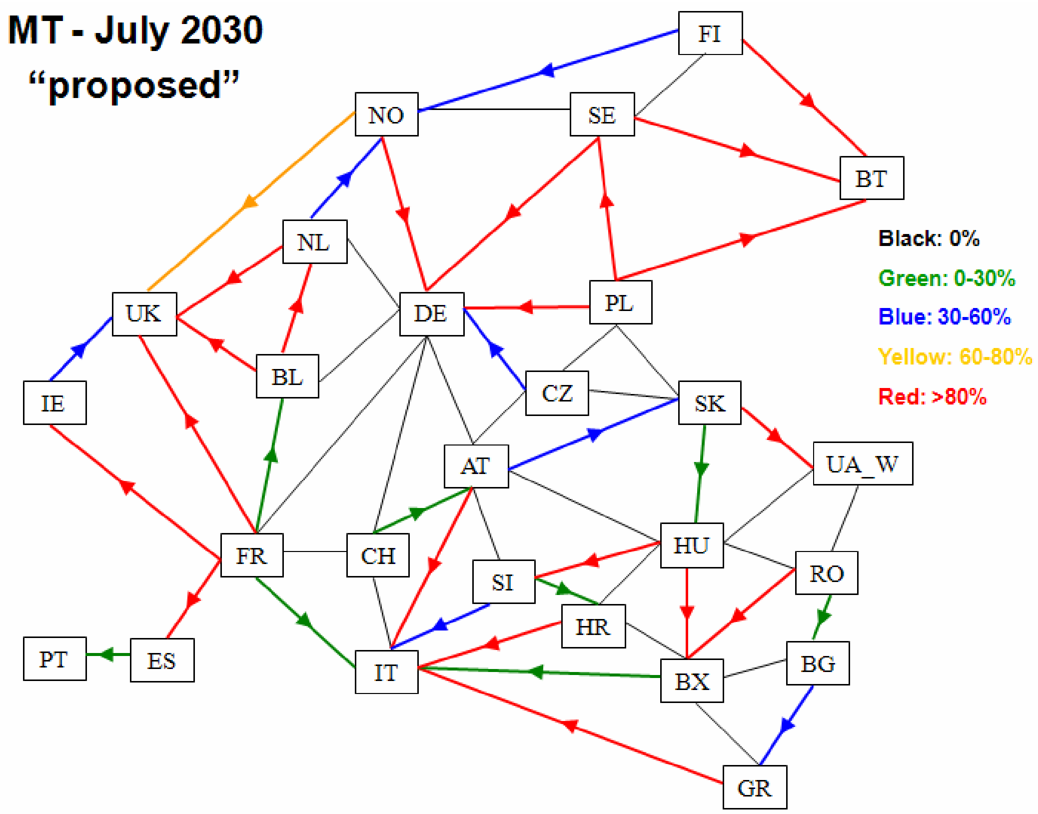

Figure 13: Percentages of hours with congestion in July 2030 with the "proposed expansion".

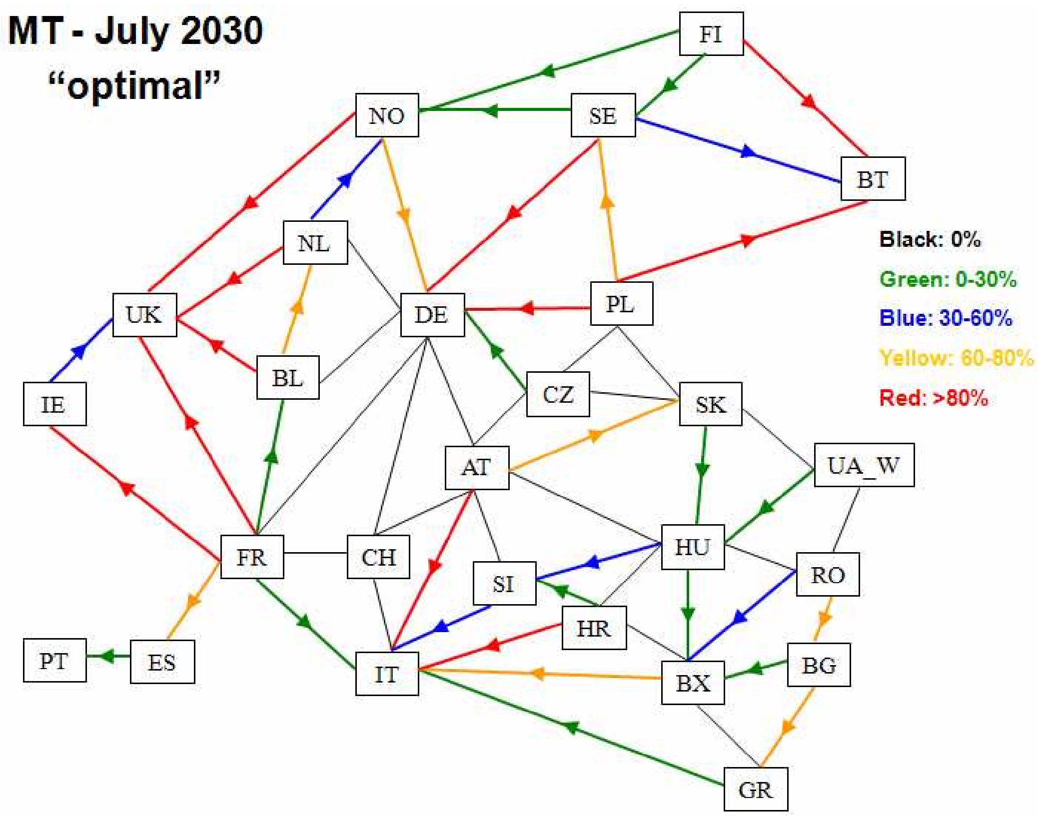

Figure 14: Percentages of hours with congestion in July 2030 with the "optimal expansion".

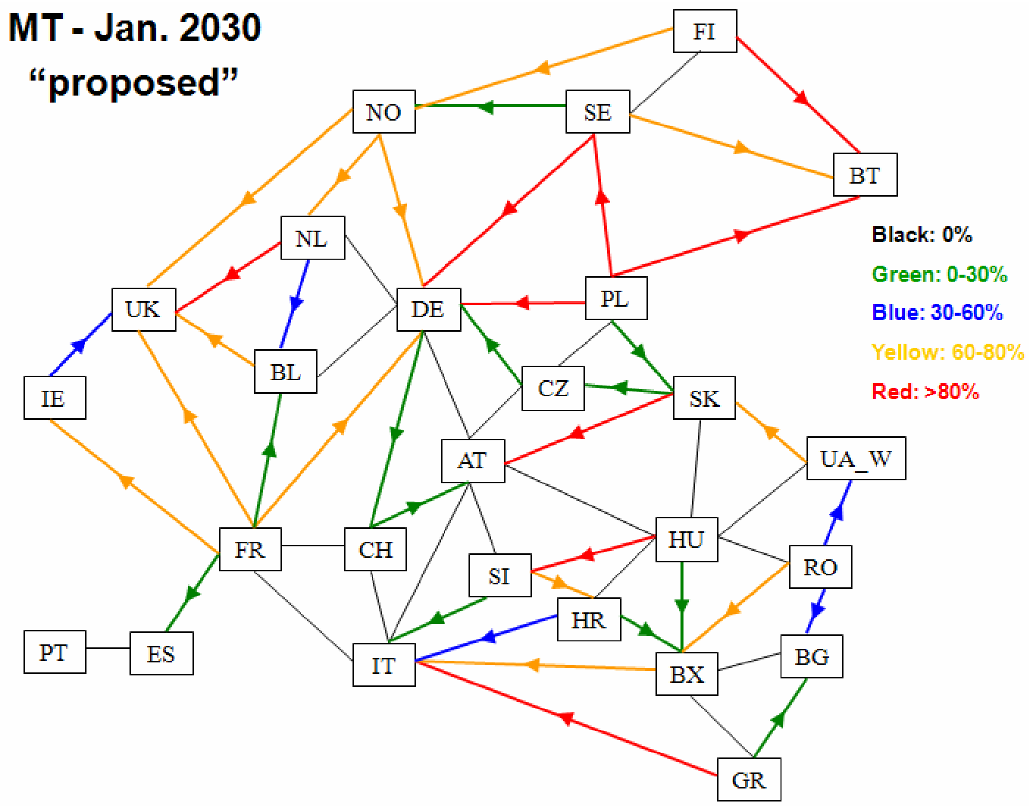

Figure 15: Percentages of hours with congestion in January 2030 with the "proposed expansion".

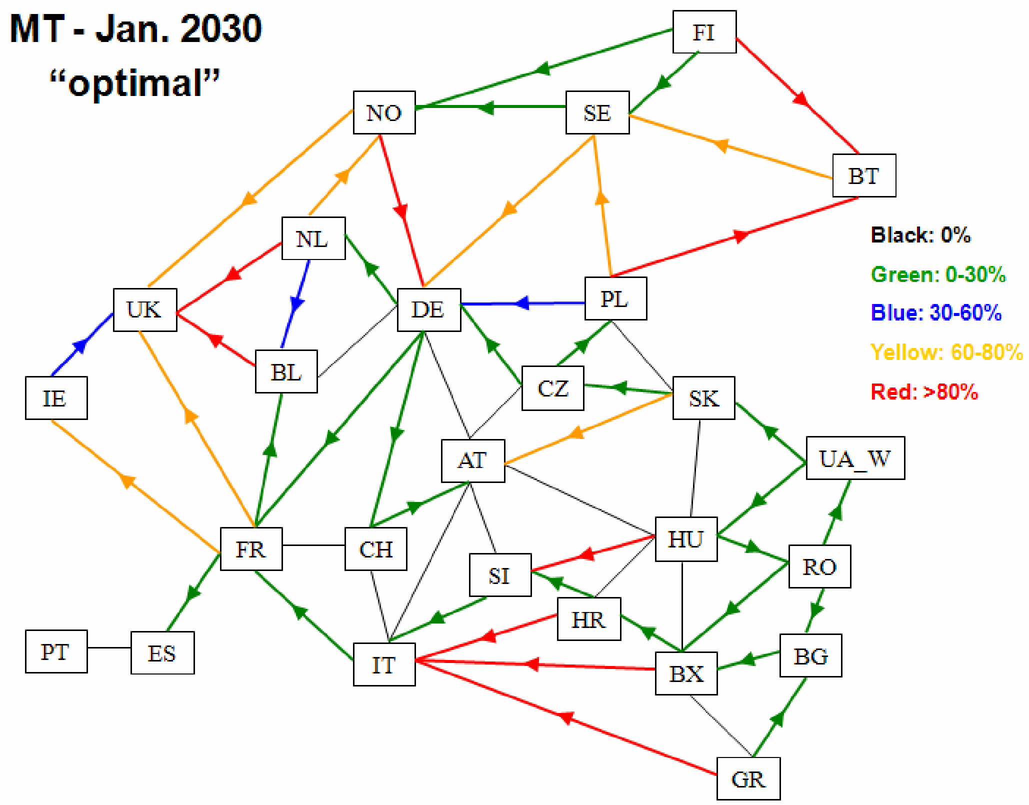

Figure 16: Percentages of hours with congestion in January 2030 with the "optimal expansion".

As for the impact on prices, in Figure 17 we report the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.
It can be noted that the main "winners" in this scenario are United Kingdom, Germany, Baltic countries, Belgium, Ireland, The Netherlands and Switzerland while the main "losers" are Romania, Poland, Bulgaria, Ukraine West and Greece.

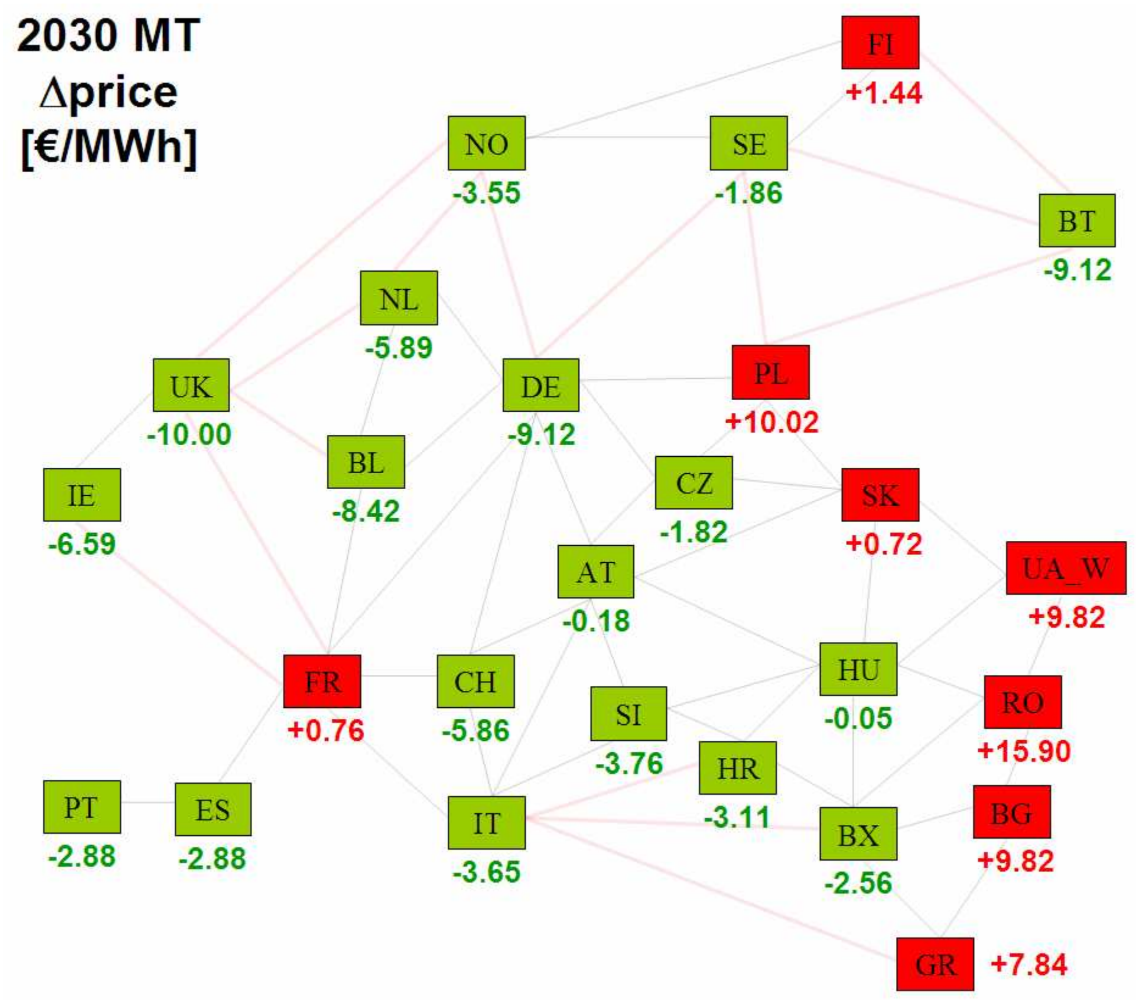

Figure 17: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2030 MT scenarios.

As for the impact on fuel consumption, the consequence of the "optimal expansion" (that reduces network constraints) is an increase of production by cheaper base-load power plants (nuclear, hard coal, lignite[7] and power plants equipped with CCS technology) at the expense of mid-merit / peak-load natural gas and fuel oil fired power plants. Overall, the greater use of less efficient generation technologies slightly increases total fuel consumption.

[7] It must be noted that this scenario is characterized by a relatively low CO_2 emissions value (24.26 €/t).

As for the impact on CO_2 emissions, due to substitution of natural gas fired generation with less efficient and more emissive (apart from nuclear) power plants, overall CO_2 emissions increase, by about **16.9 MtCO$_2$**.
As for total costs, it can be noted that a significant reduction of fuel costs (about 1650 M€) is partially compensated by CO_2 emissions allowances and by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **728 millions of Euros**.

4.4.3 2030 "EA – Europe Alone" scenario

As for the impact on congestion, in Figure 18, Figure 19, Figure 20 and Figure 21 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the "proposed expansion" and with the "optimal expansion" is reported.
In the July 2030 "optimal expansion" scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is reduced to one third.
In the January 2030 "optimal expansion" scenario, congestion is still reduced, even if in a less significant way than in July 2030.

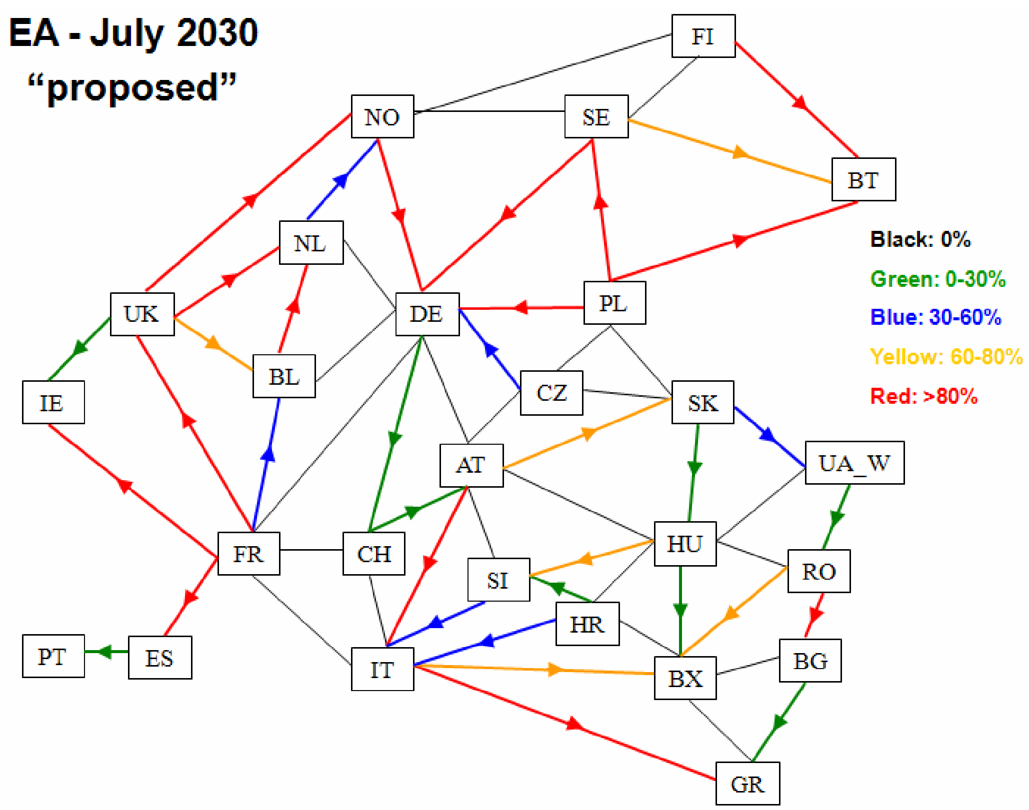

Figure 18: Percentages of hours with congestion in July 2030 with the "proposed expansion".

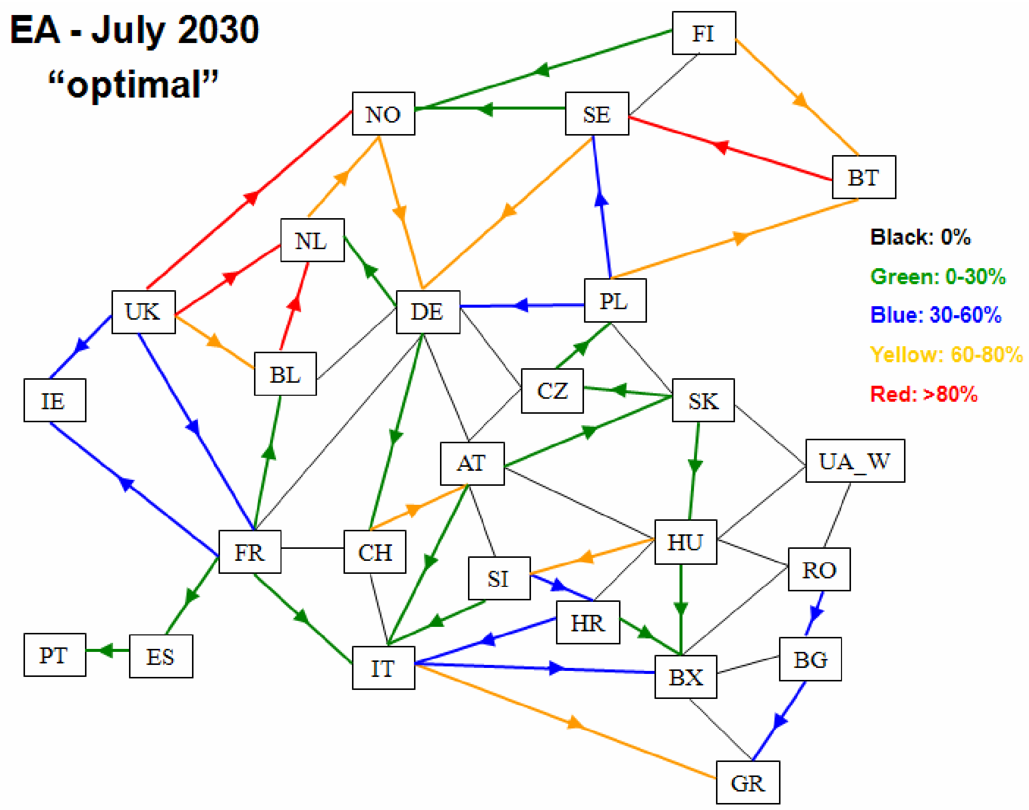

Figure 19: Percentages of hours with congestion in July 2030 with the "optimal expansion".

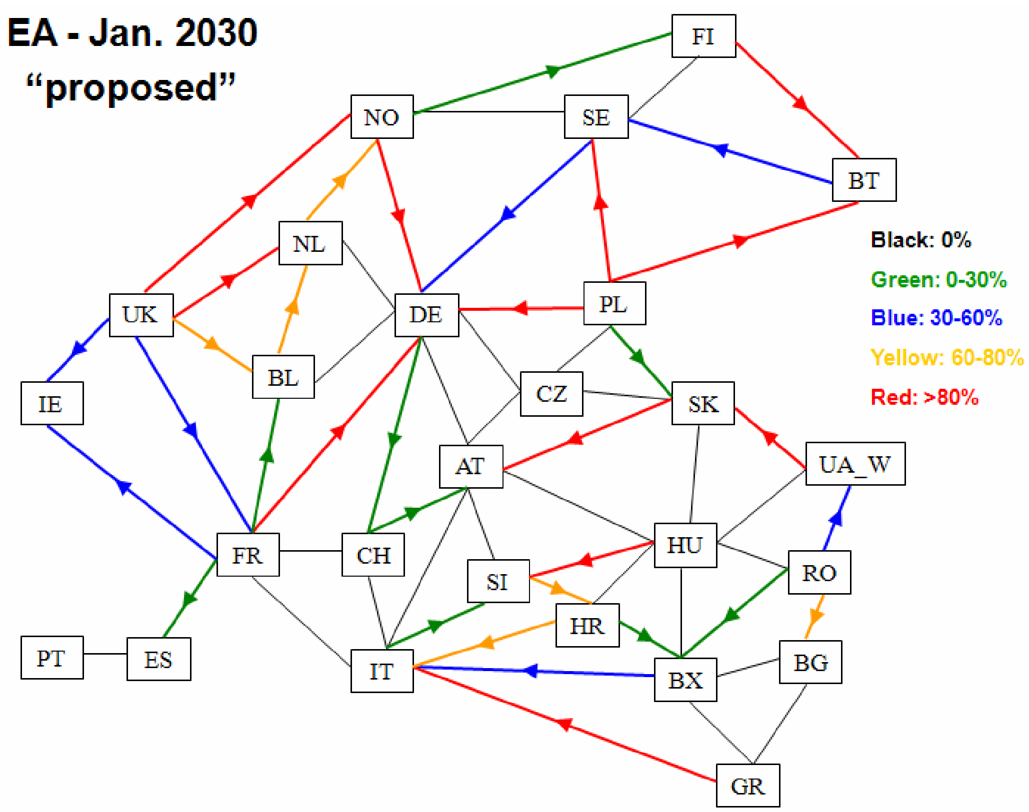

Figure 20: Percentages of hours with congestion in January 2030 with the "proposed expansion".

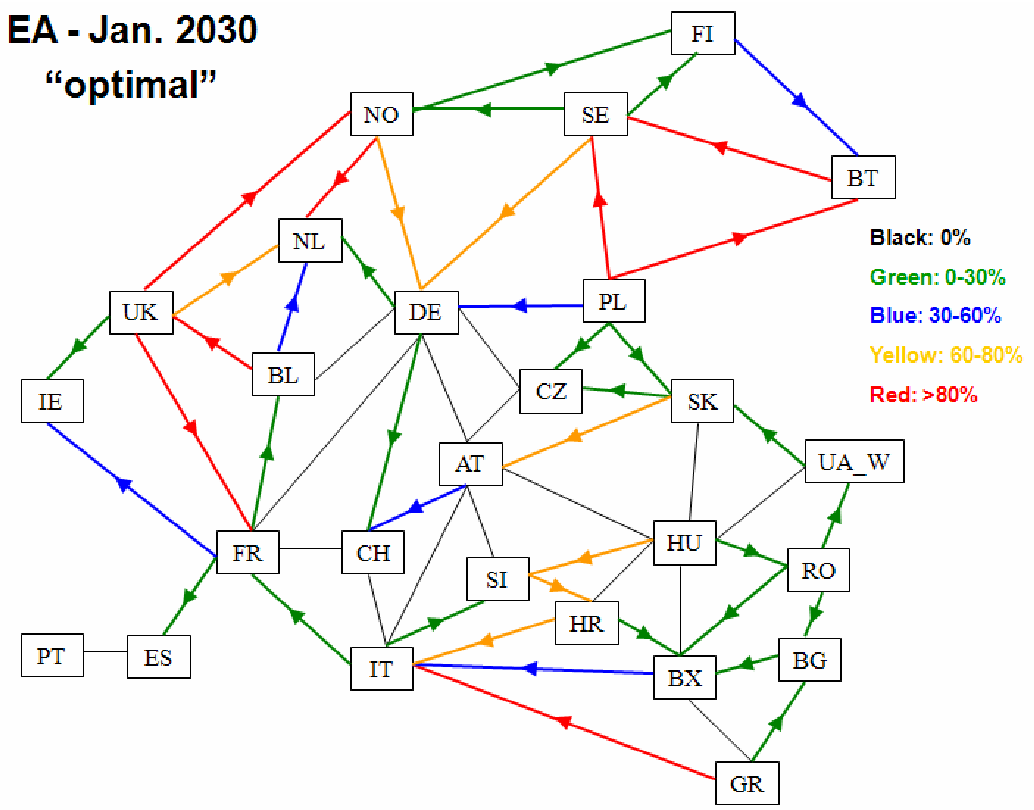

Figure 21: Percentages of hours with congestion in January 2030 with the "optimal expansion".

As for the impact on prices, in Figure 17 we report the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.
It can be noted that the main "winners" in this scenario are Germany, Baltic countries, Norway, Sweden, Finland and The Netherlands while the main "losers" are Romania, France, Ukraine West, Poland, Bulgaria, and Greece.
As for the impact on fuel consumption, the consequence of the "optimal expansion" (that reduces network constraints) is an increase of production by power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology) at the expense of the more emissive ones (hard coal, lignite and fuel oil). In fact, the "Europe Alone" scenario is characterized by a very high CO_2 emissions value (90.28 €/t). Overall, the greater use of less emissive generation technologies sligthly decreases total fuel consumption.
As for the impact on CO_2 emissions, due to substitution of more emissive generation with less emissive one, overall CO_2 emissions significantly decrease, by about **57 $MtCO_2$**.
As for total costs, it can be noted that the very high reduction of CO_2 costs (5145 M€) is only partially compensated by the increase of fuel costs and by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **4362 millions of Euros**.

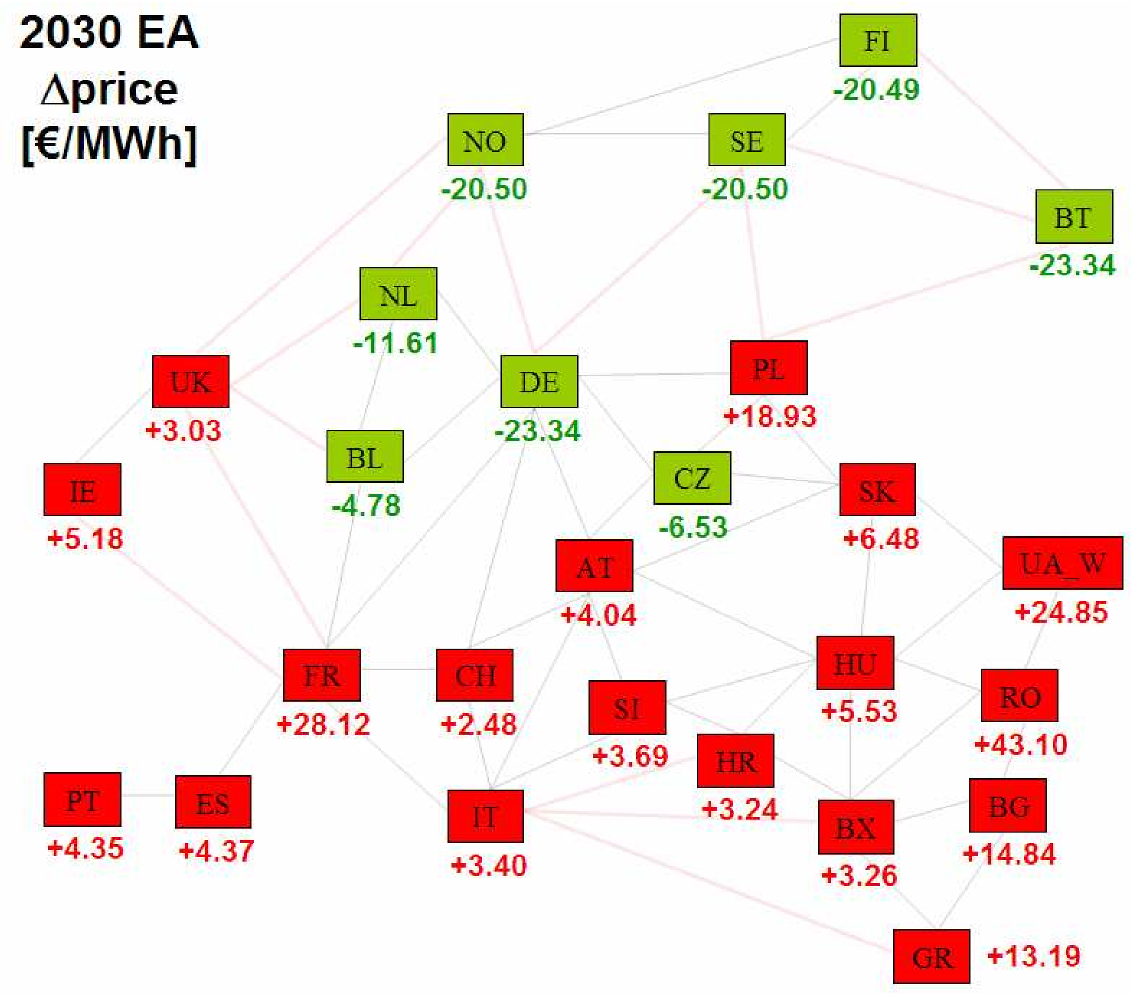

Figure 22: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2030 EA scenarios.

4.4.4 2030 "GR-FT – Global Regime with Full Trade" scenario

As for the impact on congestion, in Figure 23, Figure 24, Figure 25 and Figure 26 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the "proposed expansion" and with the "optimal expansion" is reported.
In the July 2030 "optimal expansion" scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.
More or less the same happens in the January 2030 "optimal expansion" scenario.

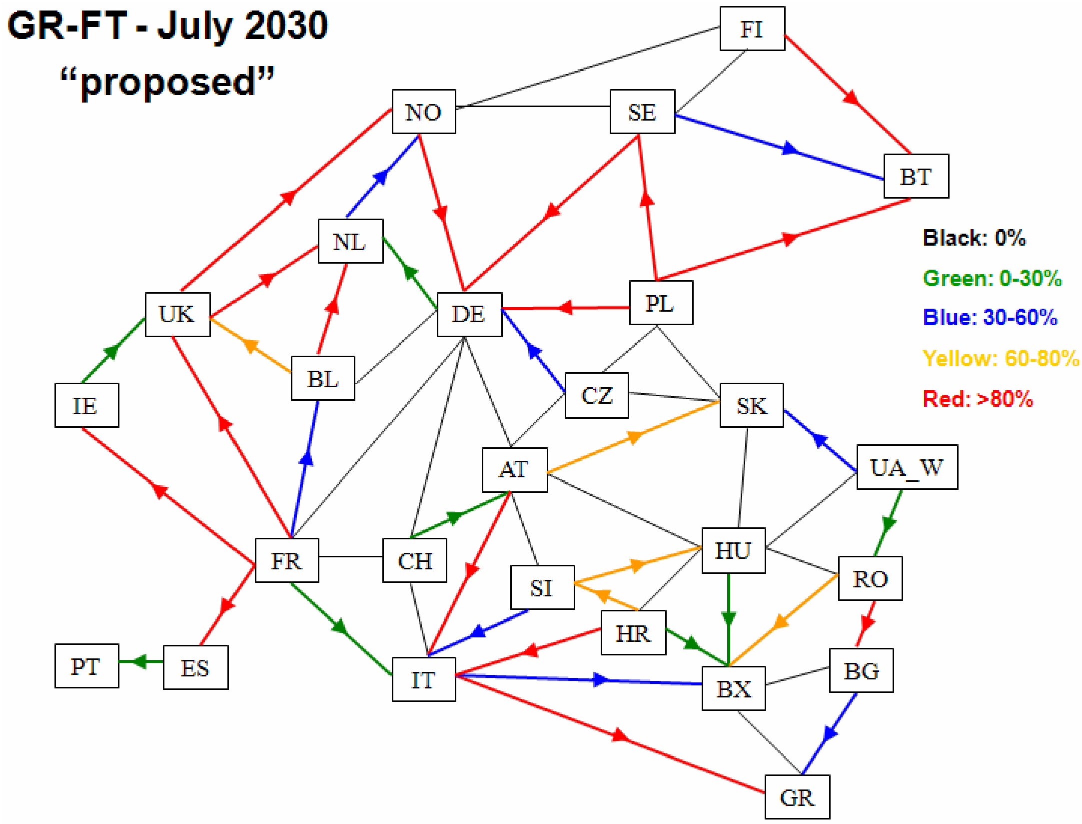

Figure 23: Percentages of hours with congestion in July 2030 with the "proposed expansion".

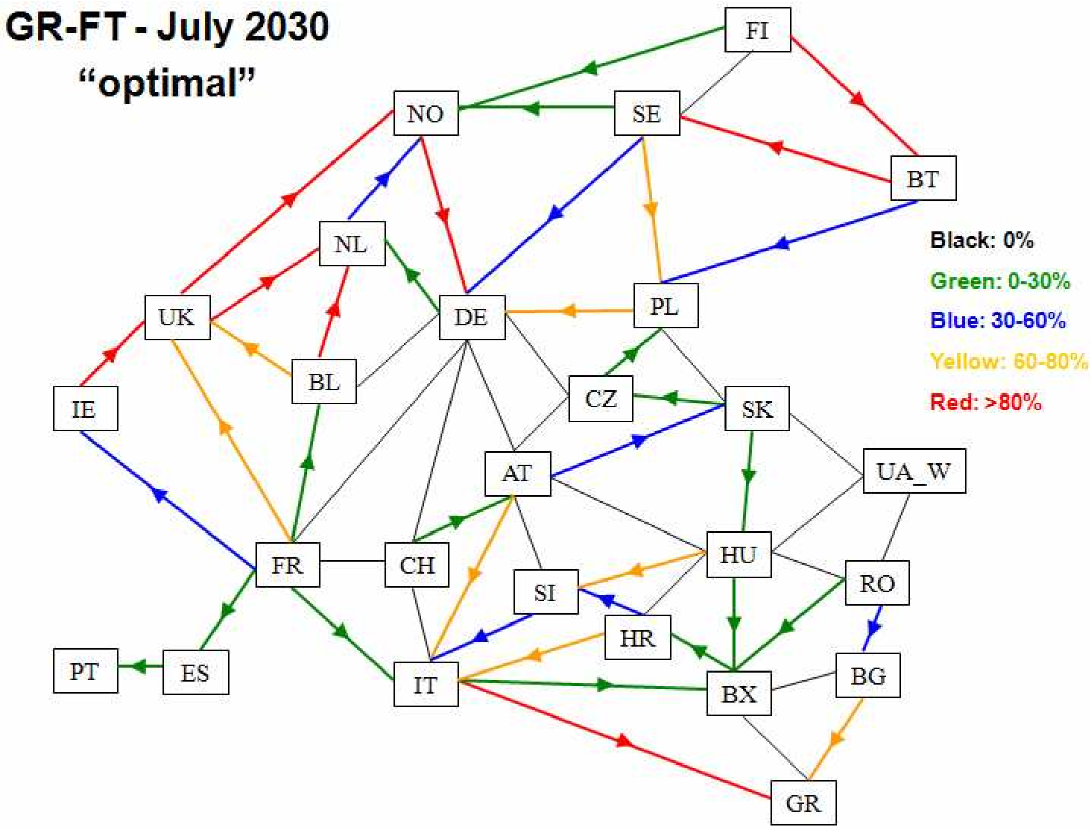

Figure 24: Percentages of hours with congestion in July 2030 with the "optimal expansion".

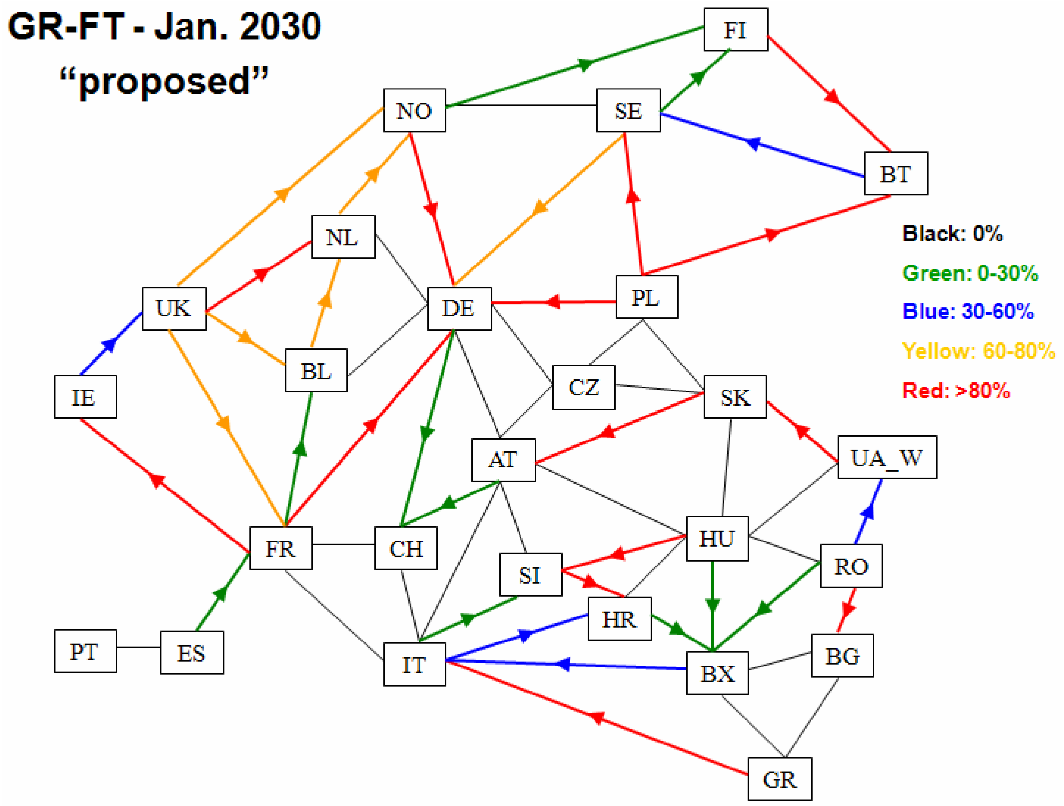

Figure 25: Percentages of hours with congestion in January 2030 with the "proposed expansion".

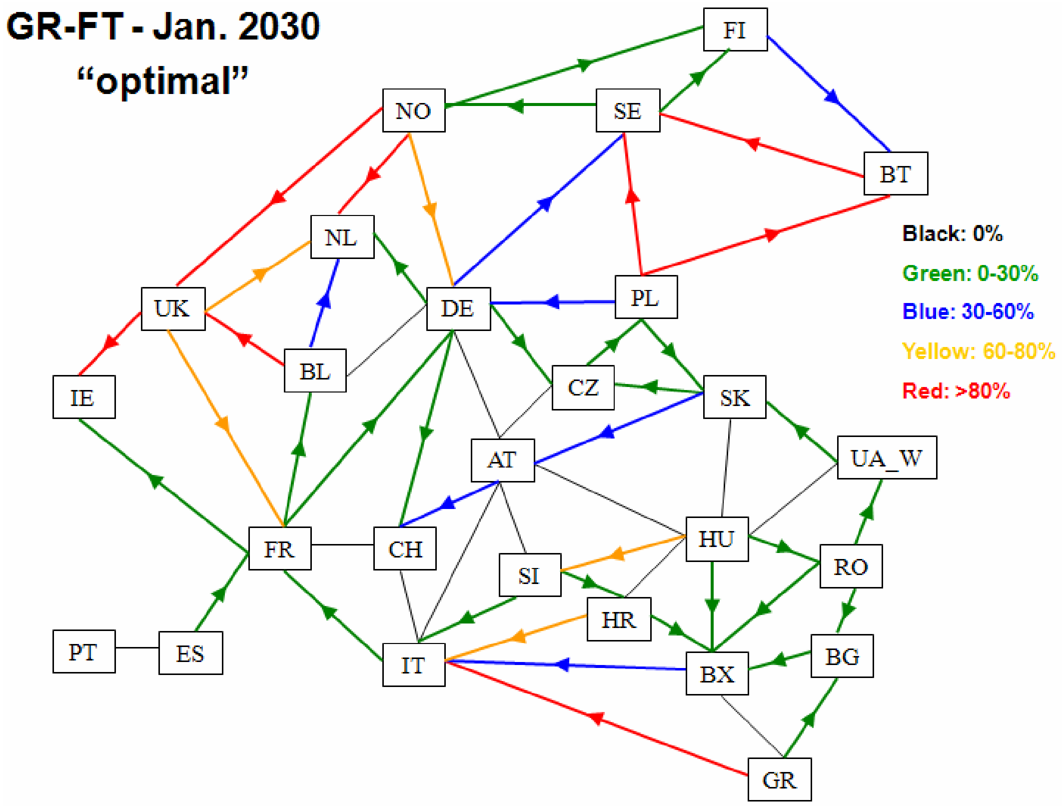

Figure 26: Percentages of hours with congestion in January 2030 with the "optimal expansion".

As for the impact on prices, in Figure 17 we report the differences between the annual average zonal prices in the “optimal expansion” and in the “proposed expansion” scenarios.
It can be noted that the main “winners” in this scenario are Germany, Baltic countries, Norway, Sweden, Finland and The Netherlands while the main “losers” are Romania, Ukraine West, France, Poland, Bulgaria, and Greece.

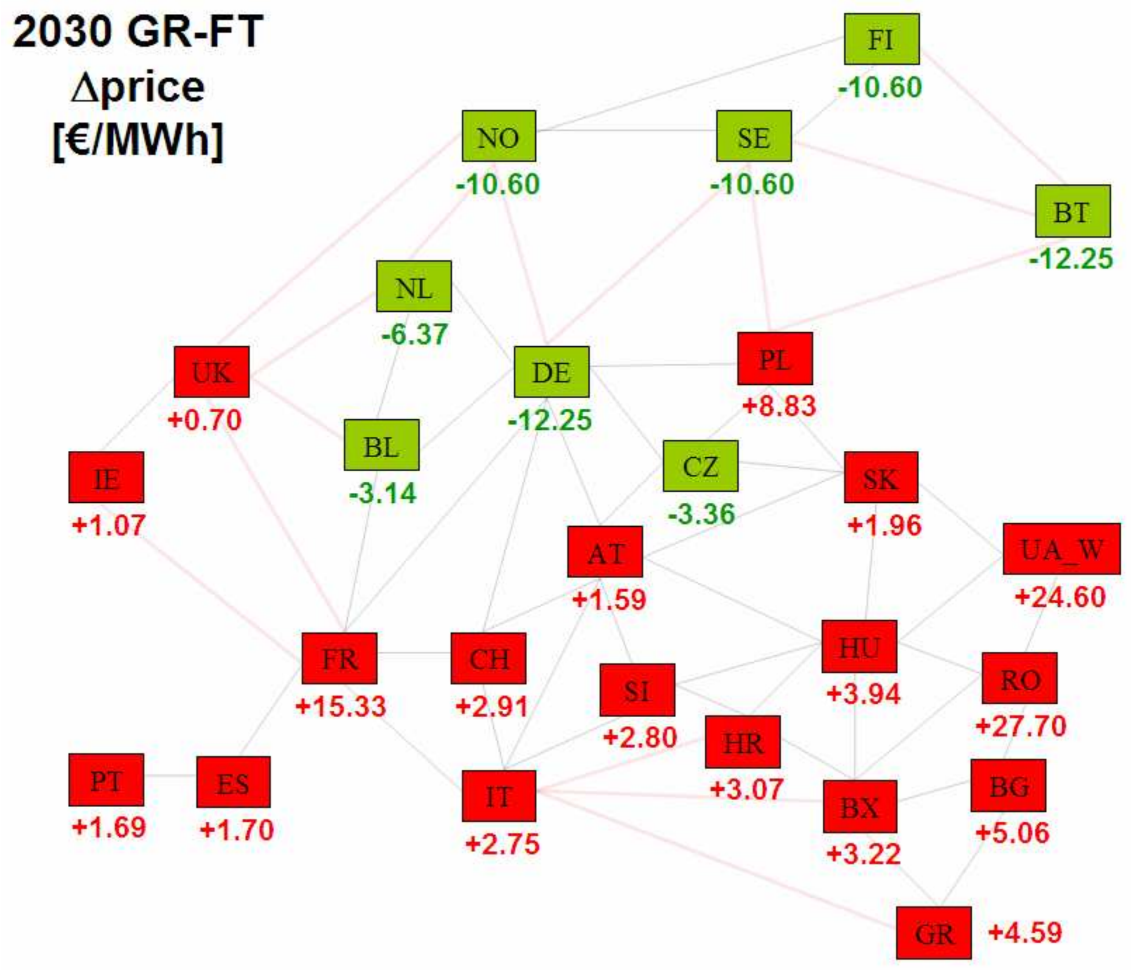

Figure 27: Zonal price differences between the “optimal expansion” and the “proposed expansion” 2030 GR-FT scenarios.

As for the impact on fuel consumption, the consequence of the “optimal expansion” (that reduces network constraints) is an increase of production by power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology) at the expense of the more emissive ones (hard coal, lignite and fuel oil). In fact, the “Global Regime with Full Trade” scenario is characterized by a quite high CO_2 emissions value (63.26 €/t). Overall, the greater use of less emissive generation technologies sligthly decreases total fuel consumption.
As for the impact on CO_2, due to substitution of more emissive generation with less emissive one, overall CO_2 emissions significantly decrease, by about **33.6 MtCO$_2$**.

As for total costs, it can be noted that the quite high reduction of CO_2 costs (2124 M€), as well as the reduction of fuel costs is only partially compensated by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **1916 millions of Euros**.

4.4.5 Comparison among scenarios

First of all, as far as security of supply is concerned, as above mentioned, it must be noted that in no one of the considered scenarios there is Energy Not Supplied (ENS).

As for cross-border network expansions, in the following Table 19, the first five interconnections with the greatest increases of transmission capacity in the "optimal expansion" w.r.t. the "proposed expansion" scenarios are reported.

2015	MT 2030	EA 2030	GR-FT 2030
ES→FR	FR→DE	FR→DE	FR→DE
FR→DE	DE→PL	DE→PL	DE→PL
DE→NO	SK→UA_W	ES→FR	SK→UA_W
DE→SE	ES→FR	SE→PL	ES→FR
FR→UK	BX→RO	SK→UA_W	BX→RO

Table 19: Interconnections with the greatest increases of transmission capacity in the "optimal expansion" w.r.t. the "proposed expansion" scenarios (interconnections that occur in different scenarios are highlighted with the same color).

It can be noted that the interconnections between **France and Spain** and between **France and Germany** are among the most expanded both in the 2015 and in the 2030 scenarios.
Moreover, as far as 2030 scenarios are concerned, the interconnections between **Germany and Poland**, **Slovak Republic and Ukraine West** and between **Balkan countries and Romania** are among the most expanded, too.
Other interconnections that are often significantly expanded in the optimal w.r.t. the proposed expansion scenarios are the ones between **Germany and Norway**, **Germany and Sweden**, **Sweden and Poland, Romania and Ukraine West, Finland and Baltic countries** and **Poland and Baltic countries**.
This means that, for the aforementioned interconnections, the proposed expansion levels seem to be far from the optimal ones under the assumptions of the considered scenarios.

Concerning the electricity price differences between the "optimal expansion" and the "proposed expansion" scenarios, the main 2015 "winner" (i.e. countries where the average price decreases) countries (i.e. **Poland**, **Portugal** and **Spain**) do not maintain their positions in the 2030 scenarios, where the main "winners" are **Germany**¸ **Baltic countries**, **The Netherlands** and **Belgium**, together with **Norway**, **Sweden** and **Finland** especially in the two most environmentally friendly scenarios (EA and GR-FT).

On the other hand, the main "losers" (i.e. countries where the average price increases) are most often **Romania**, **Poland**, **Bulgaria**, **Ukraine West**, **France** and **Greece**.

As for the impact on fuel consumption (see Table 20), it can be noted that in the 2015 and in the MT 2030 scenarios, characterized by relatively low CO_2 emissions values (respectively, about 13 and 24 €/MtCO$_2$) the "optimal expansion" causes an overall increase of fuel consumption, by reducing natural gas and increasing coal and lignite (as well as nuclear in 2015) consumptions.
On the other hand, in the two most environmentally friendly scenarios (EA 2030 and GR-FT 2030), where CO_2 emissions values are quite high (respectively 90 and 63 €/MtCO$_2$), the "optimal expansion" causes an overall decrease of fuel consumption, by increasing consumption of power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology), but significantly reducing consumption of the more emissive ones (hard coal and lignite).
In any case, the variations of fuel consumption between the optimal and the proposed expansion scenarios are not very high, ranging from +1.9 to -4.4 Mtoe.

Fuel	Δ 2015 [PJ]	Δ MT 2030 [PJ]	Δ EA 2030 [PJ]	Δ GR-FT 2030 [PJ]
Nuclear	142.8	5.9	198.5	91.1
Hard coal	77	287.3	-482.2	-173.5
Lignite	25.9	108.6	-201.3	-167
Natural gas	-164.3	-369	127.5	-22.3
Fuel oil	-	-5.4	-2.1	-1.3
Coal CCS	-	0.7	139.6	74.8
Gas CCS	-	0.2	34.4	28.1
Total [PJ]	**81.4**	**28.3**	**-185.6**	**-170.1**
Total [Mtoe]	**1.9**	**0.7**	**-4.4**	**-4.1**

Table 20: Variations of fuel consumption of non-CHP plants in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios.

The aforementioned fuel consumption data have a direct consequence on the variations of CO_2 emissions, reported in Table 21. It can be noted that, while variation of the 2015 scenario is almost negligible (due to the increase of nuclear production that compensates the greater hard coal and lignite productions), the MT 2030 scenario is characterized by a slight increase of CO_2 emissions. On the contrary, the more environmentally friendly EA and GR-FT 2030 scenarios show more significant CO_2 emissions reductions.

Fuel	Δ 2015 [$MtCO_2$]	Δ MT 2030 [$MtCO_2$]	Δ EA 2030 [$MtCO_2$]	Δ GR-FT 2030 [$MtCO_2$]
Hard coal	7.24	27.00	-45.32	-16.31
Lignite	2.62	10.98	-20.34	-16.88
Natural gas	-9.20	-20.66	7.24	-1.22
Fuel oil	-	-0.41	-0.16	-0.1
Coal CCS	-	0.01	1.31	0.71
Gas CCS	-	-	0.29	0.23
Total	**0.66**	**16.92**	**-56.98**	**-33.57**

Table 21: Variations of CO_2 emissions of non-CHP plants in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios.

As for the variations of the costs of the modeled power system, reported in Table 22, it can be noted that in the two scenarios (2015 and MT 2030) characterized by low CO_2 emissions values the main component of cost reduction is fuel cost, while in the two more environmentally friendly scenarios (EA and GR-FT 2030) the main component is by far the reduction of costs related to CO_2 emissions allowances.
In this latter case, cost savings due to the "optimal expansion" w.r.t. the "proposed expansion" can be significant, ranging from 1.9 to 4.4 billions Euros.

Cost item	Δ 2015 [M€]	Δ MT 2030 [M€]	Δ EA 2030 [M€]	Δ GR-FT 2030 [M€]
Fuel consumption	-601	-1650	237	-249
CO_2 emissions allowances	9	411	-5145	-2124
Investments / O&M AC lines	112	199	257	216
Investments / O&M DC lines	145	312	289	241
TOTAL COSTS	**-335**	**-728**	**-4362**	**-1916**

Table 22: Variations of the costs of the modeled power system in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios.

4.5 STEP 5: remedies assessment

Remedies to tackle the impact of a non optimal development of the European cross-border electricity transmission network can be put in practice both in the short and in the long term.

4.5.1 Short-term remedies

- *Dispatch more expensive generation in the importing countries*

Actually, this is not exactly a remedy to the considered threat, but a natural consequence, since cross-border network constraints prevent cheaper energy from going where it is needed.

- *Reduce demand*

Instead of dispatching more expensive generation in order to tackle the impossibility to import more cheaper energy, another possibility is to reduce demand, especially at peak load time.
In case of necessity, contracts for interruptible loads can be activated to reduce electricity demand, but this typically happens for security reasons and not only for economic reasons.
Similarly, where implemented, *Demand Side Management* programs can help reducing peak loads (for example with *Critical Peak Pricing* schemes) and the related stress on the power generation system.

4.5.2 Long-term remedies

- *Increase cross-border transmission capacity*

Needless to say, the main remedy to a non optimal development of the European cross-border electricity transmission network is to invest in new interconnections, so that the reduction of bottlenecks makes easier to transport cheaper energy where it is needed, increasing security of supply, but also allowing for a more optimized operation of the generation set and for an increase of competition in the market, with significant economic benefits.
This remedy is of course not so easy to implement, neither by TSOs, nor by private investors interested in merchant lines projects. In fact, such investments are typically affected by several uncertainties, mainly due to:

- complex legal and regulatory contexts, especially for permitting procedures, stemming from a multitude of different authorities, with different administrative levels (European, national, local) that may differ from one country to another and that may have different priorities;
- the lack of social acceptance that severely delays or jeopardizes the realisation of such projects;
- due to the long-term time horizon that characterizes network projects, the inherent uncertainty in predicting the future location and amount of generation and consumption, as well as the changes over time in the way electricity is generated and consumed, also due to the impact of different policies (and of different policy implementation options) such as energy demand reduction and efficiency, renewable energy sources integration, CO_2 emissions reduction, decommissioning of polluting units, etc.

To reduce such uncertainties:

- the establishment of the *Agency for the Cooperation of Energy Regulators – ACER* foreseen by the 3rd Energy Package should be a significant step towards a more harmonized regulatory framework at the European level;
- as for the several other authorities involved in the permitting procedures, ENTSO-E in its *"Ten year network development plan 2010-2020"* states that *"competing priorities are one of the major sources of slow development processes, requiring guidelines with a strong influence on national and also local governments in a way that all involved stakeholders are able to unambiguously prioritise projects"*;
- to speed-up permitting procedures, ENTSO-E in its recent *"position paper on permitting procedures for electricity transmission infrastructure"* provides the following recommendations:

  - ⇨ *The public interest of important electricity infrastructure projects shall be stated in law. The need for the development of these projects shall be stated "objectively" (e.g. in a list of high priority projects) and therefore the justification does not always need to be argued by TSOs during the proceedings.*
  - ⇨ *There should be clear and explicit linkage between TEN-E projects and national law (recognition of TEN-E projects in national law). The public interest of TEN-E projects should a priori be recognised by their definition.*
  - ⇨ *Authorisation procedures for strategic infrastructure projects should be centralised at one (national) level.*
  - ⇨ *The number of permits required should be reduced by creating an integrated procedure for infrastructure projects or for projects subject to an environmental impact assessment including the connection to substations with the same requirements in all regions of the country.*
  - ⇨ *The result of the procedure for transmission lines and for substations should be a building permit with the right of way that allows construction to start immediately.*
  - ⇨ *There should be simplified procedures with a shorter duration for the upgrading of existing lines (e.g. to a higher voltage).*
  - ⇨ *There should be effective and compulsory time limits to grant the TSOs legal certainty as regards the timely completion of permitting procedures (including the closing-off of submissions of allegedly new statements and evidence opposing the construction of an infrastructure project).*
  - ⇨ *There should be a clear definition of what documents are needed during the authorisation procedures (e.g. during EIA).*
  - ⇨ *Effective consultation mechanisms are vital especially at the very beginning of a project. Duplication of such time-consuming mechanisms shall be avoided if their purpose can be achieved through only one single consultation, otherwise there must be a coordination between different consultations (e.g. between the Environmental Evaluation for the whole Grid Plan and the Environmental Evaluation for the single project of the Grid Plan).*
  - ⇨ *A Region should not have the right to stop strategic national and cross border infrastructure: it should be stated that the final permitting decision should remain with the National Authorities.*
  - ⇨ *It should still be possible to build necessary infrastructure projects in protected areas (e.g. Natura 2000) if the environmental effects of these projects can be mitigated and compensation measures are taken.*

- ⇨ *There should be a simplified procedure for the assessment of the effects on the environment of certain Plans approved on annual basis (e.g. Grid Transmission Plans).*
- ⇨ *It should be possible to reserve so-called "infrastructure corridors" for high priority infrastructure projects.*
- ⇨ *Common agreement with involved parties concerning corridors and in particular common dedicated corridors for different types of infrastructure (pipelines, highways, railways, high voltage lines, etc.) would be desirable.*
- ⇨ *The relevant authorities should define new infrastructure corridors for high priority infrastructure projects.*
- ⇨ *For new infrastructure and/or upgrading of the existing infrastructure existing routes should preferably be used.*
- ⇨ *Sufficient and specialized manpower is necessary to deal with infrastructure projects in an effective and timely manner in the TSOs as also in external resources (e.g. authorities).*

- o as for the lack of social acceptance, a correct and complete information provided to the involved populations by all the concerned bodies is of paramount importance; in particular, concerns about the environmental impact of the projects (e.g. impact on natural areas, visual impact, alleged health effects of electromagnetic fields, etc.) must be discussed on a clear and sound scientific basis, in order to allow for an informed comparison between such "cons" and the "pros" of the projects;
- o as for the "pros", the public benefits of the projects must be clearly stated and quantified, especially from the security of supply, from the sustainability (in particular when renewable energy flows are involved) and from the economic points of view; also, the strategic importance that characterizes cross-border transmission projects must be highlighted with the support of the highest political decision levels;
- o the economic side of the problem is very important to gain consensus among the involved populations: they must know that the realization of the projects will reduce their electricity bills (either by imports of cheaper energy or by direct compensations), otherwise the *nimby* attitude would be their first and easiest choice;
- o as for the uncertainties concerning the future developments of generation and demand, they can be effectively tackled by carrying out adequate *scenario analyses*, just like it has been done in the present study on the basis of POLES scenarios; this approach is supported also by ENTSO-E that in its *"Ten year network development plan 2010-2020"* states that *"scenario analyses at national, regional and pan-European levels are key elements in order to decide on grid extensions and to adequately assist political reasoning"* taking into account *"fuel prices, economic and monetary conditions, geopolitical developments, meteorological conditions, technological breakthroughs, market mechanisms, regulatory and legal frameworks"*.

Up to this point we have discussed the problems related to *each generic* development of the European cross-border transmission network, but it is very important to end up with an *optimal set* of developments, according to the considered reference scenarios.

Again, this is exactly what has been done in the present study, following an approach supported also by ENTSO-E, that in its recent *"Research and Development Plan"* foresees the development of *"Advanced tools for analyzing the pan-European network expansion options according to energy scenarios for Europe (i.e. expansion optima that must be searched to maximize European welfare)"*, specifying that optima are to be searched at EU level and no longer at national level.

- *Increase energy efficiency in electricity consumption*

A greater end use electric energy efficiency would entail a demand reduction that would decrease the criticalities related to the impossibility to import more cheaper energy.
EU is supporting this process with some Directives (such as Directive 2006/32/EC of 5 April 2006 on energy end-use efficiency and energy services, Directive 2009/125/EC of 21 October 2009 establishing a framework for the setting of ecodesign requirements for energy-related products, Directive 2010/30/EU of 19 May 2010 on the indication by labelling and standard product information of the consumption of energy and other resources by energy-related products, Directive 2010/31/EU of 19 May 2010 on the energy performance of buildings, etc.) and EU countries are implementing them within the framework of their National Energy Efficiency Action Plans.
Another beneficial action would be the promotion of the above mentioned Demand Side Management programs to increase demand response in case of critical situations.

4.6 STEP 6: how remedies should be financed / paid for

4.6.1 Short-term remedies

The economic consequences of dispatching more expensive generation are in the end borne by consumers, paying higher electricity prices.
As for demand reduction, costs related to interruptible contracts are socialized in the tariffs, since they benefit the whole system with a greater security of supply.
On the other hand, *Demand Side Management* programs can reduce costs both for the participating consumers and for the system as a whole.

4.6.2 Long-term remedies

Investments in new cross-border transmission capacity can be carried out either by TSOs or by private investors building the so-called “merchant lines”.
Investments by TSOs are remunerated with a fair return through transmission tariffs defined by regulators.
Due to the strategic importance of cross-border lines, regulators may acknowledge to such projects a rate of return higher than for normal transmission lines: for example, in Italy, investments that increase cross-border Net Transfer Capacity are acknowledged an increase of the rate of return of 3% for 12 years.
As for investments in “merchant lines”, they are basically remunerated by electricity price differentials between the markets they interconnect.
In fact, due to regulations no. 1228/2003 and 714/2009, such projects may be exempted for a limited period of time (by the regulatory authorities of the Member States concerned) from Third Party Access requirement, established by directive 2003/54/EC and confirmed by directive 2009/72/EC. Such exemption may cover all or part of the

capacity of the new interconnector, or of the existing interconnector with significantly increased capacity.

As for financing issues, apart from banks, a key role is often played by the European Investment Bank (EIB), especially concerning the Trans-European Energy Networks (TENs) projects.

EIB's contribution typically does not exceed 50% of the total investment cost, in order to capitalize on its first-rate lending terms to attract other sources of financing. This enables the borrowers to set up a diversified finance plan in partnership with other financial institutions and banks. As for the borrowers, they can be public authorities or private entities, including special purpose vehicles, as well as banks and financial institutions.

Examples of cross-border interconnectors financed by EIB are the following:

- *NorNed* project, a 580 km-long HVDC hybrid bipolar submarine power cable link across the North Sea between Eemshaven (in The Netherlands) and Feda (in Norway); the project is a joint venture between the Dutch (TenneT) and the Norwegian (Statnett) TSOs that have invested 600 M€, of which 280 M€ financed by the EIB;
- *BritNed* project, a 260 km-long HVDC submarine power cable link between the Isle of Grain in Kent (UK) and Maasvlakte near Rotterdam (The Netherlands); the project is a joint venture between the Dutch (TenneT) and the British (National Grid) TSOs that invest 600 M€, of which 300 M€ financed by the EIB;
- *EWIC (East-West InterConnector)* project, a 256 km-long HVDC submarine power cable link between Woodland (Ireland) and Deeside (Wales); the Irish TSO EirGrid invests about 600 M€, of which 300 M€ financed by the EIB.

As for increasing energy efficiency in electricity consumption, even if most of the actions in this field have a "negative" cost, some promotion is necessary, typically with fiscal incentives together with obligation schemes, such as White Certificates, whose costs are socialized.

4.7 Conclusions

This study assessed the impact of a non-optimal development of the European cross-border electricity transmission network.

Indeed, such non-optimality is currently not a "threat" but a fact, since the development of cross-border transmission network, originally mainly aimed at operational security and at mutual support between different power systems, did not keep the pace with the development of demand, of generation and of the related trading needs deriving from the electricity market liberalization. This is clearly shown by the level of congestion that affects several interconnections.

Moreover, the long delays that affect new transmission projects, mainly due to complex permitting procedures and to lack of social acceptance, entail that the probability of reaching an optimal status with future developments in the next 10÷20 years is quite low.

The impact assessment of the considered "threat" has been carried out by developing and running a model of the European power system (based on the MTSIM simulator, developed by ERSE) and has been focused on the security of electricity supply, as well

as on the impact on electricity production costs and on the environmental impact (in terms of CO_2 emissions).
In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal (least cost) developments determined by MTSIM. The reference years considered in the study are 2015 and 2030.
The reference framework within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security: *Muddling Through (MT)*, *Europe Alone (EA)* and *Global Regime with Full Trade (GR-FT)*.
The results of the simulations show that in no one of the considered scenarios there is Energy Not Supplied (ENS), therefore there are no problems in terms of security of supply due to insufficient cross-border transmission capacity or to available generation capacity.
Moreover, the proposed cross-border network expansions are clearly sub-optimal: in the considered scenarios, for example, the interconnections between France and Germany, France and Spain, Germany and Poland, Slovak Republic and Ukraine West, Balkan countries and Romania, as well as several others, in the “optimal expansion” case are expanded significantly more than in the “proposed expansion” case.
In the “optimal expansion”, the countries where the average electricity price decreases (w.r.t. the “proposed expansion” case) are Poland, Portugal and Spain in the 2015 scenario, while in the 2030 scenarios they are replaced by Germany¸ Baltic countries, The Netherlands and Belgium, together with Norway, Sweden and Finland especially in the two most environmentally friendly scenarios (EA and GR-FT).
On the other hand, the countries where the average price increases are most often Romania, Poland, Bulgaria, Ukraine West, France and Greece.
It can also be noted that in the 2015 and in the MT 2030 scenarios, characterized by relatively low CO_2 emissions values (respectively, about 13 and 24 €/MtCO_2) the “optimal expansion” causes an overall increase of fuel consumption, by reducing natural gas and increasing coal and lignite (as well as nuclear in 2015) consumptions.
On the other hand, in the two most environmentally friendly scenarios (EA 2030 and GR-FT 2030), where CO_2 emissions values are quite high (respectively 90 and 63 €/MtCO_2), the “optimal expansion” causes an overall decrease of fuel consumption, by increasing consumption of power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology), but significantly reducing consumption of the more emissive ones (hard coal and lignite).
In any case, the variations of fuel consumption between the optimal and the proposed expansion scenarios are not very high, ranging from +1.9 to -4.4 Mtoe.
The aforementioned fuel consumption data have a direct consequence on the variations of CO_2 emissions: while variation of the 2015 scenario is almost negligible (due to the increase of nuclear production that compensates the greater hard coal and lignite productions), the MT 2030 scenario is characterized by a slight increase of CO_2 emissions (about 17 MtCO_2). On the contrary, the more environmentally friendly EA and GR-FT 2030 scenarios show more significant CO_2 emissions reductions (respectively, about 57 and 34 MtCO_2).
As for the variations of the costs of the modeled power system, it can be noted that in the two scenarios (2015 and MT 2030) characterized by low CO_2 emissions values the main component of cost reduction is fuel cost, while in the two more environmentally

friendly scenarios (EA and GR-FT 2030) the main component is by far the reduction of costs related to CO_2 emissions allowances.

In this latter case, cost savings due to the "optimal expansion" w.r.t. the "proposed expansion" can be significant, ranging from 1.9 to 4.4 billions Euros.

The main remedy to a non optimal development of the European cross-border electricity transmission network is of course to invest in new interconnections, so that the reduction of bottlenecks makes easier to transport cheaper energy where it is needed, increasing security of supply, but also allowing for a more optimized operation of the generation set, with significant economic benefits.

This remedy is not so easy to implement due to the several uncertainties that affect such kind of investments, mostly related to complex legal and regulatory contexts, especially for permitting procedures, stemming from a multitude of different authorities, to the lack of social acceptance and to the inherent uncertainty in predicting the future location and amount of generation and consumption, as well as the changes over time in the way electricity is generated and consumed.

To reduce such uncertainty, the establishment of the *Agency for the Cooperation of Energy Regulators – ACER* foreseen by the 3rd Energy Package should be a significant step towards a more harmonized regulatory framework at the European level. As for permitting procedures, besides being more efficient and clear, they should also have a reasonable and mandatory time limit for their duration.

As far as the lack of social acceptance is concerned, the public benefits of the projects should be clearly stated and quantified, especially from the security of supply, from the sustainability (in particular when renewable energy flows are involved) and from the economic points of view. In particular, the economic side of the problem is very important to gain consensus among the involved populations: they must know that the realization of the projects will reduce their electricity bills (either by imports of cheaper energy or by direct compensations), otherwise the *nimby* attitude would be their first and easiest choice.

Moreover, the strategic importance that characterizes cross-border transmission projects must be highlighted with the support of the highest political decision levels: the proponents of the investments must not be left alone.

As for the uncertainties concerning the future developments of generation and demand, they can be effectively tackled by carrying out adequate scenario analyses, that should be used as a reference to determine a set of cross-border network expansions that is optimal at the European level and no longer only at the national level, as done in the past: this implies the necessity of a higher level of coordination that can be effectively carried out by the European Network of Transmission System Operators for Electricity ENTSO-E.

5 Role and responsibilities of TSOs for security of supply

In the liberalization process of the Electricity Markets, networks, given their physical nature, have been considered as Natural Monopolies. The institution in charge of the transmission of electricity was named Transmission System Operator (TSO) and had the ultimate goal to ensure a secure and reliable operation of the power system, as well as to grant market participants a non-discriminatory access to the network.
As markets started to function, the complexity of this type of institution has been realized, then for over fifteen years there has been a constant debate on the institutional structure of TSOs and the most appropriate type of regulation. In Europe this issue has also an extra dimension as TSOs of different countries should work together towards the realization of an integrated market.
Our work has three aims (see also [4]):

1) to introduce the reader to the main principles of TSOs institutional design,
2) to present some of the main topics of discussion in terms of European market integration,
3) to give an update on the current activities carried out by Regulators and TSOs under the coordination of the European Commission.

All the issues discussed in the following have a direct or an indirect impact on security of supply, which is the ultimate objective ("keep the lights on") a TSO has to guarantee with its activity, both in the short and in the long term.

5.1 Role and functions of TSOs

Our objective in this chapter is to introduce the role and the functions of TSOs in the electricity system. It is not a definitive assessment, but rather an overview of the various possibilities. The definition of the role of TSOs is also clearly an ongoing process as it will evolve over time as new technologies will enlarge the set of options for the control of the system; TSOs will also have to adapt according to the type of generation available.
Our analysis is mostly concerned with institutional aspects and more specifically with topics related to the implementation of the European Commission Third Legislative Energy Package.
As in Agrell and Bogetoft[8], we can distinguish six main activities for a TSO:

1) Market facilitator
2) System operator
3) Grid builder: planner
4) Grid builder: constructor
5) Grid maintainer
6) Grid owner/leaser

In the description we will see how the type of regulatory control varies greatly across these activities; a careful analysis is then necessary in order not to produce contradicting

[8] Agrell P. and Bogetoft P. (2002): *"Charter of Accountability for Transmission Operators"*, www.sumicsid.com

or incomplete overall policies resulting from an incorrect assessment of the institutional framework.

1) **Market facilitator**: TSOs are fundamental in the development of markets as their actions can significantly influence prices, with the impact being both on short term variations and long term trends. In order to support the day ahead and balancing markets it is key that the TSO should be able to perform the dispatch efficiently and provide adequate and transparent information to market participants. On the long term side the main tasks are the connection of new generation and the building of the Transmission Network. The TSOs can have a huge impact as these are actions with a fundamental impact on future prices and that have to be taken using the correct information concerning the system and the evolution of global Energy Markets.
2) **System operation** refers to the dispatch of generation, congestion management and the acquisition of ancillary services. In terms of regulatory control it is a challenging task to verify the effectiveness of the decisions taken by the TSO as there are strong informational asymmetries between the TSO and the Regulator. There is a great deal of institutional complexity as system operation deals at the same time with the safety of the system and the market outcomes. Increasing operation margin often increases market prices as there are more chances of creating congestion. These issues become more complex at cross border level, where several operators are involved.
3) The **planning of the network** is possibly the most difficult issue to address since the change to liberalized markets. The TSO has the role of optimizing the system under the monitoring/approval of the Regulator taking into consideration the evolution of demand and generation capacity. The key issue is that network investments determine the value of supplied electricity and then the profitability of generators; it is then understandable how the actions of the TSO should be under close scrutiny. Unfortunately there are no real alternatives to this form of centralized planning as merchant lines (grid investment made by private investors) are a solution only for specific issues; this is due to the unique nature of the network, which does not allow a satisfactory computation of the allocation of the costs of grid expansion. There are two additional factors affecting grid investments: first these have a lifetime of at least 30 years, second these are basically not modular (they cannot be executed incrementally). It is then clear the great degree of uncertainty concerning the effectiveness of decisions, which should be based on long term forecasting.
4) **Grid building** is a regulated activity and is not covered in our analysis; the point is to have the system built in the cheapest way given the quality of the components and the conditions where lines are placed. Overall efficiency is very hard to estimate as there is for example a trade off between quality and durability of assets that is hard to estimate given the long lifespan of assets. One interesting remark is the fact that this activity can be either carried out by the TSO or being outsourced: this has a considerable impact on the type of company as one choice or the other can affect drastically its size.
5) **Grid maintenance** is relevant for our study as it has safety implications. In terms of regulation, there are indexes of quality of performance, which are designed to give some incentives, still there is a lack of comprehensive regulatory assessment of the activity.

6) **Grid ownership:** the financing of the infrastructure has generated a constant debate since the liberalization. The tendency to privatize the network has never been widely accepted for the electricity sector, where the investments should take into consideration also security and public service aspects. The rates of return on the assets are basically negotiated with public authorities and networks have often been considered by utilities an excellent investment with a very low risk factor.

TSOs can also play a key role in the process of ensuring both in the short and in the long term **generation adequacy**, i.e. its capability to keep the supply/demand balance (taking into account network constraints).
Generation adequacy is mostly related to the availability of an installed capacity sufficiently larger than the expected peak load, i.e. the availability of a sufficient *reserve margin*. Nevertheless, the sole amount of installed generation capacity is not sufficient to ensure adequacy, since in addition the generation set must be well *adapted* to the load, as well as to the increasing penetration of intermittent renewable sources: this means that the composition of the generation set in terms of base-load, mid-merit and peak-load power plants (characterized by different operating flexibility), as well as in terms of dispatchable and non-dispatchable ones, must be correctly balanced.
In this respect, it is widely recognized that electricity price signals coming from the market are, by themselves, not sufficient to ensure generation adequacy, mainly due to informative asymmetries and to lack of sufficient competition that make market players unable to collectively obtain an "optimal" development of the generation set, both in time and in space (i.e. in terms of location in the network).
Moreover, the often long and uncertain permitting procedures, as well as investors' risk aversion that makes them wait until they can be pretty sure of the profitability of new investments, introduce significant delays between the moment when a new power plant is needed and the moment when it becomes available.
This could cause the so-called *boom-and-bust cycles*, where periods with high reserve margins and consequent low electricity prices that do not incentivize new investments, due to subsequent progressive load increase and to decommissioning of old power plants, alternate to periods with low reserve margins (therefore with low security of supply) and consequent high electricity prices, that could lead to a new wave of investments, thus restarting the cycle.
To tackle the aforementioned problems, in several electricity markets worldwide, regulatory authorities, under the approval of Governments, defined and/or implemented specific intruments such as tendering procedures for new capacity, capacity payments, capacity markets/obligations, call options, etc.
According to Regulation (EC) no. 714/2009, Transmission System Operators (TSOs) are in charge of assessing the present and future adequacy of the power system both at the national level and, through ENTSO-E, also at the European level. In doing so, we suggest that TSOs should not only "passively" try to envisage the future generation development according to market players' investment behavior, but they should support the implementation of the aforementioned adequacy instruments being "proactive" and providing a technical evaluation of how much new generation capacity of the different types is needed, when and where (the location in the network is very important), on the basis of scenario analyses concerning in particular demand evolution, intermittent renewable sources penetration and network development.

Of course, it would be desirable that this whole process could be coordinated and harmonized at the EU level to increase its effectiveness and to avoid market distortions.
Furthermore, it must be taken into account that a generation set that is adequate in terms of installed capacity and in terms of composition could again be insecure if its fuel mix is not sufficiently diversified, so that a large amount of capacity could become unavailable in case of a fuel supply shortage.
In fact, the objective of a greater primary source diversification could be reached using the same above mentioned regulatory instruments concerning capacity adequacy; of course, the highest political levels responsible for the overall energy policy are in charge of the quantitative definition of the objective itself: in this case TSOs could only play the role of consultants for technical aspects concerning the implementation of the objective and its impact on system adequacy.

Given this short description of the basic functions, we can try to define the institutional arrangements concerning the organization of transmission. We need to clarify that there is no "one size fits all" approach, as it has to be taken into account what is the final purpose of the categorization.
In Leveque et al.[9] there is a review of the literature and several innovative ideas aimed to define what type of organization would work better to serve the purpose of integrating European Markets. Their classification is based on two dimensions:

- the separation of ownership between Generation (G) and Transmission (TO),
- the relationship between transmission ownership and system operation (SO).

The first point deals with "ownership unbundling", an issue which has not been solved in Europe yet. There are many variations of how separation can be put in place: it is possible to simplify the matter defining companies, which are actually independent (I) of each other and those, which have a single owner, but have differentiated legal structures (L).
The second point can de divided into two institutional arrangements: Transmission System Operator (TSO), where there is a single company dealing with all the six activities of the Agrell and Bogetoft list; or System Operator (SO) and Transmission Operator (TO), where the SO deals with functions 1 to 3 and the TO with the remaining three.
It is possible to combine these functions and institutional arrangements to provide four reference institutional frameworks:

1) The independent transmission system owner and operator (**ITSO**), where there is a single company, independent by generators, managing SO and TO.
2) The legally unbundled TSO (**LTSO**), where there is a vertically integrated company with legal separation of activities.
3) The **ISO/ITO** where these two activities are completely separated by the rest of the industry.
4) The Independent System Operator (**ISO/LTO**) where the SO is an independent company (not for profit), with the assets owned by vertically integrated utilities.

[9] Lévêque F, Glachant J.M., Saguan M., de Muizon G. (2008): *"Comparing electricity transmission arrangements"*, www.microeconomix.com

Still following Leveque et al. we quote a series of five criteria, which have the purpose to compare different institutional arrangements in order to define which would be more suitable to support the objectives set by the European Commission in terms of markets integration.

1) **Transaction cost savings**: if we consider the functions of a TSO there is an advantage, from the coordination point of view, to have them grouped in the same company. This is also valid from the point of view of the users, who have to interact with only one company.
2) **Performance Based Regulation implementation**: PBR is a mechanism, which has the aim to improve the efficiency of the company taking into account a larger spectrum of parameters in the analysis of the productivity of a firm. A more standard approach is Rate of Return (ROR) regulation, which simply considers observed costs. PBR is better suited to capture the interactions of assets with the control (costs of balancing and congestion management) and maintenance of the system.
3) **Conflicts of interests**: these can arise inside an integrated company (ITSO) as different entities could have diverging objectives. There are clear examples as the tradeoffs between investment and congestion management/balancing, which could induce to sub optimal decisions, increasing the level of the investments as these bring superior profits. In terms of Security of Supply and reliability there are also clear issues in terms of allocation of responsibilities among different entities with all the possible institutional arrangements. In the case of vertical integration, there is a lack of transparency as it could be difficult to determine ex-post what went wrong, both in terms of operations and in terms of planning/investments. In the cases where there is unbundling (any type), there are risks of coordination failures[10], which could lead to take uneconomic decisions. The measures taken can induce overinvestment in networks, reduced use of network capacity, excessive mandatory reserves and excessive investments in generation capacity.
4) **Non discriminatory access**: basically we refer here to the creation of a level playing field. There are three possible dimensions: i) the release of data by the TSO; ii) the possibility to connect at fair tariffs; and iii) the fair allocation of network capacity and the guarantee of a socially efficient development of the network. In terms of data TSOs should guarantee that the adequate type of information is available to market participants in a non-discriminatory manner. TSOs also should provide a socially optimal use of network capacity in order to allow socially efficient transactions and a cost reflective development of the grid.
5) **Benefits from regional integration**: this is aimed to check how the characteristics of a TSO would be compatible with the process of integration with other TSOs as it is under way in Europe. We can point out two general dimensions: i) the set of regulatory mechanisms used to coordinate operation (e.g. balancing markets, congestion management, etc.) and ii) the institutional framework. This is to say that good rules are not enough, these have to be backed by institutions, which have the adequate competences to monitor and enforce the decisions taken. This is clearly the direction taken with the Third

[10] In this kind of situation also the ex-post allocation of responsibilities would be complex.

Legislative Package, which started the process introducing new actors like ACER (the agency for the coordination of Regulators) and ENTSO-E (the association uniting all the previous TSOs associations).

We have then presented three categories: i) a description of the activities, ii) four options in terms of organizational structure and iii) five possible criteria to compare the efficiency of TSOs institutional arrangements.
These categories are clearly arbitrary: they have the purpose to help understanding and comparing companies. Each TSO has a very specific organizational structure and a very unique business environment, which can only be partly captured by a general definition.
The point is that TSOs, even if organized using a common framework, could have still disparities that should be taken into account when implementing policies.
We can list some factors:

- The overall mission of TSOs is the obligation to provide non discriminatory access to the network. This means that the TSO cannot select its customers, which is a clear constraint as there is no full control on all the aspects of the business.
- The territory (type and size) and weather conditions are such that TSOs could be confronted with different challenges both in terms of operations and investments.
- The same applies with the energy mix, which is characterized in this specific moment in history by a great deal of uncertainty in terms of its possible developments.
- Policy obligations: a TSO being a monopolist defines its objectives jointly or under the close scrutiny of Public Authorities. An energy policy having an impact on so many areas of society can clearly be a variable difficult to control and which can exacerbate differences among operators.

The concepts laid out will give us the basis to present some of prominent issues concerning TSOs and the development of an integrated European Electricity Market.
We have three institutional topics: i) the choice of congestion management method, ii) merchant lines and iii) the choice of organizational model of TSO.
Then we will take a look at the current institutional activities: i) the work program of ACER, the recently formed association for the cooperation of Energy Regulators, ii) the Ten Year Network Development Plan of the association of the European TSOs ENTSO-E and iii) the ENTSO-E Research and Development Plan.
The aim is to give on one side the flavour of the discussions behind the institutional design and on the other side an update on how policies are being currently implemented.

5.2 Institutional Topics

5.2.1 Congestion Management

In this section we will give an overview of the options in terms of congestion management for the European Market[11]. The topic of market integration has a long history with solutions developed since the early 90's in Scandinavian countries and since 2000 in Central Europe. It keeps being extremely actual as the system will have to accommodate more renewables, requiring an increase of network investments and the use of smart grids.
Congestion management is essential in order to understand the value of investments both in terms of generation and of transmission; with RES the location of investments cannot always be freely decided and then it is often not close to the zones with higher consumption. It is then clear the importance of a correct assessment of the value of the transmission grid as it can be a considerable part of the whole investment.
With RES the use of the interconnections across systems would also be increased since, given the random nature of generation, this cannot be coordinated with load, with the ensuing necessity of redirecting flows towards demand in other control areas. Using congestion management adequately it is possible to increase the available capacity of the interconnectors to avoid additional grid investments. Another positive effect is the possibility to have more flexible markets, which are capable to fully use the available information, approaching then trading and real time operations. This would impact the development of Demand Response and facilitate the use of wind or other RES forecast data.

There are currently two systems in Europe for cross-border congestion management: explicit auctioning of physical transmission rights and market coupling.

Explicit auctioning has market participants acquiring through auctions transmission rights for specific interconnectors between two countries. The auctions are carried out before market results and TSOs jointly decide the quantity of rights available.
Market participants then, in order to complete their transactions need a corresponding amount of transmission rights. TSOs use balancing services in order to compensate for deviations with respect to the planned dispatch.
This type of auction is limited by the fact that it is based on estimates both by TSOs and by market participants. TSOs have to assume network conditions to determine the available capacity on the interconnectors and market participants need to forecast the price differentials across markets. The output then could be not efficient as forecast errors or attitudes towards risk could lead to undesired outcomes. TSOs for example could reduce the capacity made available as otherwise they would incur in balancing costs. As markets clear the day ahead also the auction does not have the necessary flexibility to incorporate accurate wind forecasts, which can be obtained only few hours in advance.

[11] We follow K. Neuhoff (2011): *"Europe's Challenge: A Smart Power Market at the Centre of a Smart Grid"*, Climate Policy Initiative.

Market Coupling[12] is a method that uses the bids on the power exchanges to integrate markets in different areas. Power Exchanges are informed by the TSOs about the available capacity between countries, then they use the bids subject to the transmission constraints to clear the markets. If we compare it with the explicit auctioning then the market participants do not participate in the auction for transmission as their bids are automatically taken into consideration for the cross border markets.

Besides these two there are also two other available options that could be taken into consideration in order to improve the performance of the system.

International Loop Flows: as we have seen in the previous examples only specific interconnectors are auctioned. Power flows in practice do not follow a unique path, but separate at the origin taking different routes according the laws of physics. Then a transaction could go through several borders implying different calculations for transmission capacities. Then we can see how in the previous types of auction a simplified approach has been taken, that has the consequence of inducing TSOs to give a conservative estimate of the available capacities. In order to calculate power flows it is necessary to know the origin of the generation, which is not made available to other TSOs. It has been then proposed to take this information into the calculations in order to increase the accuracy of the forecast.

Locational Marginal Pricing (LMP): LMP represents a market where prices at each node[13] reflect transmission and generation constraints.
These location-specific prices are made up of three components: energy, congestion and losses. The energy component (or marginal cost) is defined as the cost to serve the next increment of demand at the specific location, or node, which can be produced from the least expensive generating unit in the system that still has available capacity. However, if the transmission network is congested, the next increment of energy cannot be delivered from the least expensive unit.
The congestion component, or transmission congestion cost, is calculated at a node as the difference between the energy component of the price and the cost of providing the additional, more expensive, energy that can be delivered at that location. The congestion component can also be negative in export-constrained areas where there is more generation than demand.
Nodal prices are adjusted to account for the marginal cost of losses. If the system was entirely unconstrained and there were no losses, all the LMPs would be equal and would reflect only the energy price.
In order for market participants to hedge for price differences between nodes LMP type markets provide Financial Transmission Rights (FTR). FTR are financial instruments that entitle the holder of the FTR to receive a share of the excess payments collected for congestion costs that arise when the transmission grid is congested in the day-ahead market. The amount of money of the FTR can be used to offset congestion costs incurred for higher Locational Marginal Pricing that market participants may have to pay, or it can be an additional source of revenue for Financial Transmission Rights market speculators.

[12] This method is currently used for the interconnections between France, Germany, Belgium and the Netherlands. It is also called implicit auctioning as market participants do not bid directly for interconnection capacity.
[13] A node is a point in the system where either electricity is injected or extracted.

Comparing the models one can notice that we have presented them according to an increasing ability to represent real situations. Market Coupling incorporating transmission bids into power exchanges is more flexible with respect to Explicit Auctioning as it does not require market participants to forecast the necessity of cross border transactions.

The International Loop Flows methodology captures the impact of cross border loop flows on the system, with clear advantages in terms of planning and definition of availability of lines.

LMP adds an additional dimension as it considers also the congestion occurring inside the control areas, which is very frequent. It can help then to have a better view of the system for planning purposes as there is more information on the value of the network, but also to reduce the number of critical situations as there is less need of redispatching.

LMP also allows to better operate intra-day and balancing markets. These would have an increasing importance with the deployment of RES and Demand Response.

Intermittent generation can be forecasted with accuracy only few hours before dispatch, it is then not fully compatible with day ahead markets. Then it is important to have performing intra-day and balancing markets as it could be a way to integrate these resources more efficiently and having them considered as a support and not a problem for the network.

The same applies to Demand Response which needs flexible markets in order to fully exploit its potential.

Market Integration then offers some attractive features:

- Visibility of the system: TSOs having full visibility also of other control areas can have a dramatic improvement of their understanding of the overall system. This can reduce unexpected emergencies that in the past have occurred for a lack of transmission of information across control areas. TSOs then can take more easily coordinated actions to react to accidents.
- Pricing reflective of transmission constraints: this is not possible with the first three methods as these are based on estimates of the TSOs, also performed with a limited knowledge of the system. The consequence is not having a realistic valuation of the cost of producing and transmitting electricity.
- Generation constraints: using full information on the system allows to take into account production patterns of individual units (start up costs and ramping). The effects are also an increase in efficiency and the reduction of risks of having unexpected unavailable generation.

LMP being a well defined methodology which produces large amounts of information would facilitate the regulatory control of TSOs activities[14]:

- It would eliminate the risk of collusion with national or vertically integrated producers through limiting access to national markets.
- It would also allow a better monitoring of TSOs internal management.
- As we have mentioned before, the definition of available cross border transmission capacity could induce to unnecessary conservative estimates. The incentive of TSOs are either the reduction of risks of increasing operational

[14] Basically it would reduce or eliminate the asymmetries of information between Regulators and TSOs.

costs or the preference to motivate network expansion rather than using it more efficiently[15].

The scope of this overview is not to propose solutions, but rather to show the basis of the current discussions on improvements of the congestion management procedures and the consequent implications for TSOs.

5.2.2 Merchant Transmission Lines

Merchant Transmission Lines are grid investments developed not by TSOs, but by private investors in order to exploit price differences created by bottlenecks between areas. They are not subject as TSOs assets to tariff regulation and Third Party Access (TPA), but they are compensated with special schemes which have the purpose to stimulate this specific type of investments.
Given the objective of creating an integrated European Market and the current situation of underinvestment in interconnections, they have been considered an interesting tool to achieve current policy objectives.
Following Rious[16] we are interested here in the analysis of institutional risk, which investors should consider before taking their decision.
First it is necessary to define the differences between the investment approach of a regulated TSO and that of private investors.
TSOs have the objective to optimize the transmission network, in economic terms this means equating the marginal cost of additional transmission capacity with the social benefits, which in a market model is the price difference between zones.
It is a standard case of public goods, that however then does not fit necessarily into the logic of a monopolist as the profits deriving from price differences do not allow to recover fixed plus variable costs.
The monopolist would choose instead to build a smaller capacity, which implies a higher price differential. The optimal capacity for a monopolist is set at the point where the marginal cost of building equals the marginal revenue given by the price differentials, the point where congestion rents are maximized.
Permission to build lines is granted by Regulators, who accept non-optimal investments as they are still improving social welfare with respect to the situation where these were not carried out.
This is a network expansion at no cost where the lines are used only if it makes sense from the economic point of view; customers are not charged for the lines, they pay only if they use them.
The question is then why these lines are then not being built by TSOs; apart from permitting procedures, there can be multiple reasons, we can say that often when two countries are involved welfare improvements and allocation of costs cannot be easily assessed, not inducing TSOs to find an agreement.
Clearly the asymmetry in regulatory regimes give different incentives, then it is not surprising that under certain conditions private investors could replace TSOs.

---

[15] The TSOs could option for an unnecessary development of the network as it could reduce the operational risks and increase their asset base.
[16] Rious V. (2010): *"Regulatory risks for merchant interconnectors in the European electricity network"*, www.microeconomix.com

In the Third Package of the European Commission there are rules for handling decisions over Merchant Lines.
The investors have to ask permission of exemption from TPA (or to be able to retain the rights of congestion management) to the involved regulators; ACER, the Agency for the Cooperation of Energy Regulators, can intervene only to mediate if Regulators have different views and give an advice on the application, but it cannot overrule the decisions taken at national level.
It is then a case of subsidiarity, which is in a way reasonable as it deals with clear interference on national interest.

In the Third Package there are guidelines for determining if Merchant Lines could be accepted:

(a) the merchant interconnector should enhance competition in electricity supply;
(b) the level of the risk is such that the investment would not take place unless the exemption is granted;
(c) the interconnector must be owned by a person legally separate from the TSOs;
(d) charges must be levied on users of the interconnector;
(e) since the partial market opening referred to in Article 19 of Directive 96/92/EC, no part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission or distribution systems linked by the interconnector;
(f) the exemption is not to the detriment of competition or the effective functioning of the internal electricity market or the efficient functioning of the regulated systems to which the interconnector is linked.

The principles from (c) to (e) are fairly straightforward as they deal with standard unbundling arguments. Clearly participation to the ownership by TSOs could give incentive to perverse strategies in order to increase the demand for the Merchant Lines, with consequent extra profits.
Lines also should not be financed through tariffs, but rely only on congestion charges paid by users in order not to interfere with standard TSOs revenues.
The three remaining points instead, even if their rationale is fairly evident, might lack effectiveness in terms of implementation.
It is easy to agree on the principle behind condition (a), but it seems difficult to verify if competition is effectively increased by the investment. For example investors might back their investments at any time with long term contracts, which could bring negative effects. These still could be hardly verified ex-ante as also their impact could vary over time.
Condition (b) is vague as we do not see how the risk could be estimated. It also does not deal with one typical feature of these exemptions or the duration. Investors negotiate a period of time, which is necessary to allow to recover investments; the risk factor it is then captured by the length of period under which the investors are allowed to keep congestion charges.
Condition (f) partly duplicates (a), being a sort of a softer version, probably more suitable to the situation as it indicates that investments should not be allowed which could favour anti-competitive practices. It is important to notice also the part of interference with the system, as there is the possibility to increase system costs if new lines are introduced.

We can see how the discipline is based on very uncertain parameters that do not seem to give the necessary framework to start what is a costly application procedure by the potential investors.
It should be then made an effort to provide a legislation, which could help investors to realize ex-ante the potential of approval of their investments, instead of having to rely on what is basically a on a case by case procedure.
The regulatory framework as a matter of fact, if the objectives are considered a potential benefit for the society, should be a facilitator especially in a sector where there are structural conditions that do create a complex business environment.
Transmission investments have very high costs and a long life span of 30 years or more, revenues depend on price differentials between markets. If we think about the day ahead the investment analysis should focus on the joint hourly volatility in the two markets connected by the merchant line.
All these factors present great challenges for investors that should be taken into consideration in the drafting of Regulations.

5.2.3 Organizational models for TSOs

Following again Leveque et al. (2008), we present their proposal for comparing models of TSOs. It is an extremely interesting reflection on the functions of TSOs considering the context where they have to operate.
The purpose of the study was to take fairly standard results on the institutional structure of TSOs and show that what seems obvious for a single market could deserve a different interpretation if put in the context of an European market, which as first priority has the integration of national markets.
Previously we have shown their methodology which states a series of five criterion that they use to compare different TSOs institutional arrangements. They perform a qualitative test for each criterion on each institutional arrangement giving either a negative or positive mark. To compare they sum the positive and the negative and make considerations on the weight each criterion should have. The methodology is clearly really simple, but it allows to develop a framework for decision making through the process. There is clearly no empirical test capable to assess the quality and the performance of these institutions, thus this is a useful alternative with results that have to be taken as a starting point for discussion rather than conclusions.
These results are based on theoretical designs in order to be used for implementation purposes. The quality of the institutions, if not performing adequately, can easily alter the effects assumed in the theory.

Taking the case of a single system we go through the different criteria.

1) **Transaction cost savings**: For this the important factor is the coordination between activities. Operation, maintenance and investments cannot be considered separately. Then ITSO and LTSO are better performers. It can be said that the administration costs due to separation of activities are only a small fraction of the total costs of transmission. Still in terms of strategy possibly some synergies are lost in the separation of operations and planning.
2) **Performance Based Regulation implementation**: Also for this criterion having the activities integrated could be more desirable. An ISO could have less

incentives to perform as it could not have to bear the full consequences of his actions. An ITSO would be induced to plan the network to reduce congestion costs, an ISO is not responsible for planning then this effect could be lost. Also it might be less costly for the regulator to extract informational rents dealing with the two activities with one firm rather than with separate firms.

3) **Conflict of interests**: in this case the preferred structure is the ISO. The integrated companies could have the interest to favour in the planning procedure to increase their assets rather than optimize choosing also other solutions (centralized generation, distributed generation, lower voltage networks). In case of accidents it could also be easier for an integrated company to distort the information concerning responsibilities.
4) **Non discriminatory access**: non discriminatory access is clearly an issue for a vertically integrated company as the incentives are against giving access to generators owned by competitors and to reduce the transmission network to increase market power.

Then in order to capture the cross border dimension the fifth criterion has to be checked.

5) **Benefits from regional integration**: the evidence seems to go against the ITSO model as international experience shows that ITSOs do not seem to achieve cooperation easily. In terms of operation they can increase their profits not revealing information over their network reducing available capacity; in terms of investments they would try to shift the costs of interconnectors to others as again due to informational asymmetries it is difficult to allocate costs. These effects would be enhanced by a weak regulatory regime over cross border issues. As a matter of fact National Regulatory Authorities might not have also any incentive to optimize welfare at the European level as their implicit duty is to preserve national interests. There are examples (PJM in the US) in favour of an ISO as a type of company that can integrate easily other companies as to coordinate with one or more asset owners would not present a great obstacle. Also PJM and the US market show examples of agreements across ISOs of neighbouring areas.

The results of the analysis can be then summarized by the following table.

	ITSO	LTSO	ISO
Transaction cost savings	+	+	-
PBR implementation	+	+	-
Conflict of interest	-	-	+
Non-discriminatory access	+	-	+
Benefits of market integration	+	-	+

In order to have a ranking what is necessary is to have an assessment of the weight of each criterion.
ITSO remains independently of the weights the best option for an isolated system, but this could not be true for an interconnected system.
If the reduction of transmission costs given by a better internal organization and a better performing regulation then the ITSO model is still preferable. This case could apply to

systems with weak interconnections, similar prices and internal congestion: basically a reduced need/possibility of international transactions and priorities in terms of cost reduction at national level.

Instead an ISO could be preferred for systems with an high level of international exchanges and conflict of interest. On these lines an extreme solution for Europe could be to transfer the duties to a unique ISO without necessarily changing the ownership of assets.

This type of conclusion is clearly questionable, but it has solid arguments especially if it is considered with the adoption of LMP in terms of market design.

5.3 Implementation

After the analysis of topics in institutional design in this chapter we will cover three topics, which are the result of the implementation of the Third Legislative Package. We have then the description of the 2011 work program of ACER, the ENTSO-E plan for research activities and a description of Ten Year Network Development Plan activities also by ENTSO-E.

5.3.1 ACER program 2011

One of the most frequent topics under discussion concerning the implementation of the European Electricity Market has been the necessity of a single European Regulator. As a matter of fact the process of market liberalization could not be deployed efficiently without a legal framework, which could address the interactions occurring across borders. It has been clearly shown that cooperation on a voluntary basis among NRAs (National Regulatory Authorities) could not tackle issues in terms of trading, network investments, connection of large offshore wind and large disturbances to the network created by wind.

The Third Legislative Package on the Liberalisation of the Energy Markets is a very concrete attempt to provide a suitable legal framework to support an effective integration of the national markets.

In this section we are not going to go through the history of the process that started from the creation of the association of European Regulators (CEER) and a series of coordination activities, but we will rather pragmatically focus on the implementation of the package and especially on the work program of ACER, the newly formed Agency for the Cooperation of Energy Regulators.

As can be seen from the name the Agency is not the European Regulator, but rather an institution with no legislative powers and with the task to coordinate the activities of NRAs and their interaction at European level with the stakeholders.

There was no agreement in the preparation of Third Package to transfer significant powers at EC level, still in principle it is a significant progress with respect to the previous situation. All the main issues hampering the completion of the IEM have been identified and a series of dedicated actions have been established.

This function is not negligible as there are clear problems in this type of context where work has to be allocated to each NRA and also to other stakeholders. An independent institution with a separate dedicated budget can provide the necessary drive in terms of management and provision of the necessary information. It can also improve the transparency of the process in terms of reporting to the public bodies and other stakeholders.

The list of the main duties is the following:

- In terms of TSOs the monitoring of the cooperation at regional level and the completion by the tasks assigned to ENTSO-E by the directive.
- The monitoring of the internal market with the duty to report to the Commission and the Parliament.
- To develop the Framework Guidelines for Network Codes according to the priorities set by the European Commission. The Guidelines are not binding.
- To verify that the Network Codes developed by ENTSO-E on the basis of the Framework Guidelines are, in fact, consistent with such Guidelines.
- Making recommendations to assist regulatory authorities and market players in sharing good practices.
- Consulting interested parties, where appropriate, and provide them with a reasonable opportunity to comment on proposed measures such as network codes and rules.
- Contributing to the implementation of the guidelines on trans-European energy networks.
- Contributing to the efforts of enhancing energy security.
- Take individual decisions based on specific cases related to the NRA, cross border infrastructure and other tasks.
- Decide on cross-border capacity allocation and congestion management and on TPA exemptions for new infrastructure when it is asked to do so by the concerned NRAs or when they fail to reach an agreement within a specified time period (generally six months, which can be extended to twelve months).

The governance is composed by a Director who is accountable to the Administrative Board (AB), which has the role to verify that all the tasks are carried out. The AB has nine members, five chosen by the Council and two each by the European Parliament and the European Commission. The Board of Regulators provides guidance and advice especially on recommendations and decision issued by ACER. The members are senior official of NRAs and one non voting member from the Commission.
There is also a Board of Appeal that will decide on the appeals with respect to the decisions taken by ACER.
ACER will start its activities in March 2011 in Ljubljana after an interim period in Brussels.
In this section we give an overview of the work programme for 2011; it is interesting to highlight a remark by the current Director indicating how the actual work to be carried out could be planned up to certain degree as the duties of ACER depend very much on external contributions and requests. This can be clearly inferred by the list of tasks for example the cases of requests of exemption of TPA.
ACER is responsible for the supervision of the yearly program of ENTSO-E, the aim is to monitor that the program follows the basic principles behind liberalization or promoting competition, guaranteeing non discriminatory access and a sufficient level of interconnectivity between markets.
The other tasks directly related to ENTSO-E concern the Ten Years Development Plan; ACER has to provide an advice on the plan. As this is the first year of activity ACER

will build on the preparatory work of ERGEG and the dedicated working groups, which are constituted by representatives of NRAs.
ACER is responsible for the drawing of Framework Guidelines for Network Codes, these guidelines are the result of a consultation process. The ENTSO-E will have the responsibility to draft the Network Codes, which eventually will be reviewed again by ACER.
The following Framework Guidelines for Network Codes are envisaged for completion in 2011:

- Capacity allocation and congestion management
- Grid connection
- Operational security
- Balancing

ACER will also continue previous activities developed by ERGEG in terms of monitoring national markets. This requires a special focus on guidelines for the collection of data and definition of indicators in order to have homogenous information that can allow benchmarking exercises.
Each NRA has to deliver a national report on the developments in the Electricity Market. ACER has to monitor this activity, collect the reports and produce a benchmarking report and a general assessment on the evolution of markets.

The priority topics for 2011 should be the following:

- Monitoring the progress concerning the implementation of projects to create new interconnector capacity.
- Monitoring compliance with electricity and gas regulation and related active guidelines.
- Monitoring the Regional Initiatives of TSOs, especially the implementation of the Network Codes and related binding rules.
- Monitoring compliance with consumer rights.

ACER has the role of coordinating not only NRAs and TSOs, but also to ensure a transparent and effective consultation process involving all the relevant stakeholders. On the program there is a commitment to develop standard procedures to guarantee consistency. This activity will follow the work done by ERGEG that already launched several consultations in recent years.
The consultation process will be complemented by a series of events with the purpose of collecting opinions and also to present the final documents.
ACER will also act as a coordinator of regulators and in the program is indicated how there will be a progressive change aiming to have ACER as a sole responsible eventually suppressing ERGEG. There is no precise arrangement indicated on how formally the interaction will work, only the fact that a working group will be established comprising representatives of NRAs, ACER and the European Commission.
Being the program of the first year of activity it is hard to foresee the effective impact of ACER on the future evolution of the European Market.
On one hand the approach clearly covers all the relevant issues that is necessary to tackle to support an effective integration of markets and the security objectives, on the other hand there are concerns of the possible lack of instruments or resources.

It should be verified that the lack of legislative power would not be an obstacle to resolve issues that concern a large number of Member States and stakeholders. This could have an impact in terms of type of decision as the result could be an excessive degree of compromise and in terms of timing as there is a high risk of long delays.
Another crucial point is the production of knowledge supporting the decision making; the current process is very decentralized assigning responsibilities to NRAs and associations. It has then to be seen if, even with the support and monitoring of ACER, it will be effective and would not suffer of a lack of high quality expertise or the impossibility to generate the adequate resources to finance studies on the relevant topics.

5.3.2 ENTSO-E research activities

In this section we will give a brief overview of the European Network of Transmission System Operators for Electricity (ENTSO-E) Research and Development (R&D) plan. The purpose of the report is to present the research activities carried out by ENTSO-E as required by the Third Legislative Package[17].
We find useful to analyze it as it allows to identify the major challenges faced by TSOs and the related level of additional knowledge needed in order to achieve them.
The plan is not being developed in isolation, but it belongs to a series of EC initiatives like the European Electricity Grid Initiative (EEGI) and the Strategic Energy Technology (SET) plan. The EEGI[18] is a platform for TSOs and DSOs to develop R&D, the SET[19] coordinates a series of industrial platforms like the EEGI, setting the overall priorities in terms of development of Energy Systems.
ENTSO-E could have a direct role in developing R&D, but the main task is to define topics and monitor the project portfolio, focussing especially on an adequate level of TSOs participation and the dissemination of results to all the stakeholders (Utilities, Regulators, European Commission, NGOs, etc.).
The first plan was produced in 2010 and should be updated every two years.
The plan is a support to the ENTSO-E vision for the development of the European Energy Policy; the following general principles are not new, but they are complemented by the specific angle given by TSOs to each of them:

- Security: this is seen in terms of coordinated operations, indicating how the objective is to have a fully coordinated system.
- Adequacy: a common plan of grid investment to support market integration objectives and the deployment of RES.
- Market: the development of a well functioning integrated European Market, based on standardized principles and a transparency framework.
- Sustainability: basically the deployment of the Smart Grid technologies that facilitate the RES integration.

ENTSO-E also lists several actions which will support the vision:

[17] https://www.entsoe.eu/rd/
[18] http://www.smartgrids.eu/
[19] http://ec.europa.eu/energy/technology/set_plan/set_plan_en.htm

- Collaboration with manufacturers.
- Collaboration with research centres and Universities enhancing the exchange of information and providing a stable financial support framework.
- Testing of the results by ENTSO-E members.
- An increased use of ICT solutions to achieve a greater system flexibility.
- Cooperation with DSOs and manufacturers in order to stimulate the use of Demand Response as a necessary tool to use to balance intermittent generation.

Given the general principles, we are going to analyze the four work streams or clusters of activities; we will give only a stylized description of the two addressing only technical issues.

Markets and Regulation

The attention here is given to the role of *market facilitator* given to TSOs. After liberalization there has been an ongoing struggle between an efficient market design and the limitations imposed by physical properties of the transmission of electricity. This area is then extremely interdisciplinary as it has to take into account both economics and technical approaches. In this area the regulatory issues related to integration of decentralized generation are also analyzed.

<u>Regulation and Distributed Energy Resources (DER)</u>

There are several open questions related to the deployment of DER. As a matter of fact the complexity of the interactions in Electricity Systems does not allow a clear understanding of the cost benefit analysis of these technologies. Moreover there is no clear answer on what should be the institutional set up which would allow to include all the benefits.

- Network expansion and connection of DER: determining connection rules and an institutional framework to promote an optimal network expansion.
- Computation of emission savings of DER technologies.
- Innovation incentives: to develop specific incentives schemes to support innovation at DSO level.
- The development of a regulatory framework for Storage and Demand Response.

There are two overall recommendations: to work towards homogeneous national regulatory frameworks and the inclusion in the regulatory methods of provisions for quality of service and reliability.

<u>Dynamic Market Simulation Tools</u>

This topic deals with cross border operations and investments and their impact on price formation in Electricity Markets.

- Modelling the strategic behaviour of TSOs as essential actors in the market.
- New methods of cross border congestion management.
- The development of methodologies to assess the impact on investments on markets efficiency.

- The impact of long term contracts on markets.

These topics are not new, but what is important to underline is the approach proposed. There is a commitment to integrate physical and network market models, involving directly TSOs with their expertise and data.
Also it is recognized the non neutral position of TSOs, implying the necessity to study the incentives of TSOs to implement the desired action from a regulatory perspective. The risk of underestimating the strategic nature of TSOs is to develop rules that possibly will be not be followed adequately. As a matter of fact legislators have to take into account the informational asymmetry that often complicates the monitoring.

Cross Border Balancing and System Services

Due to the development of RES system services will be required to be more performing. Two areas are indicated, one dealing with operations and the other concerning market settlements:

- Maintaining frequency within predefined limits.
- Online management of network congestion arising from erratic deviations.

DER Deployment

An analysis of the possible solutions to deploy DER; the focus is on aggregation/virtual power plants solutions. This implies to define a better coordination between TSOs and DSOs as one of the purposes of aggregation is to have DER interacting with markets and also offering balance and system services.

Pan-European Grid Architecture

The first cluster has the objective to tackle the issues concerning planning and investments in transmission infrastructure. The process of liberalization and integration of the European Electricity Markets created the need to propose new methodologies in terms of planning and solutions in order to cope with recent environmental and socio-economic constraints.
The drivers are well known: the lack of coordination in investments across countries, the increase of transit on cross border lines and the frequent lack of acceptance at local level of transmission lines.
These issues require a consistent regulatory framework, which could help overcoming the current shortcomings with transparent rules in terms of cost allocation and permitting procedures.
There are three axes of research.

Scenario Building

It is unavoidable in order to support a large investments plan to establish medium and long term scenarios (2030/50) for demand and generation.
The exercise will be carried out without considering network constraints, but only generation. The options will have to consider current and possible future European

Policy options. It is remarked how it will be explicitly modelled the impact of storage and demand response on peak demand.
It is not indicated, but the results should support the ENTSO-E Ten Year Network Development Plan, which will be covered in the next chapter. It is instead indicated the creation of a tool box with open access to be used in order to discuss the results with the stakeholders.

Modelling Tools and Software Solutions for Assets Planning
The activity is self explanatory, we should highlight the remarks in the document on the necessity as a part of the development to define the operating rules for security and establish the principles supporting the role of the transmission grid. This indicates as one of the real issue the fact that it is necessary to be accurate in defining the tasks of TSOs at national and European level.

Architecture for Pan European System

System architecture is based on the two previous activities and the technical research developed in the other clusters. The provisions are an attention to the long term evolution of the system in order to follow the life cycle of the investments and the inclusion of regulatory measures.
The regulatory issues are again key as cost allocation among TSOs is a key issue for the development of the European grid.
In Europe in order to maximize welfare it is not possible to allocate costs on what has been built inside a system as many investments should be undertaken to address contingencies in other areas. It is then necessary to have tools which assess who are the beneficiaries of the investments and charge them an adequate amount. Examples can be countries which are transit areas (generation and load being in other countries) and then have no incentive to reinforce their system if not adequately compensated.

Technology and Training

The last two clusters are dedicated to technology, simulation tools and training of operators. We will indicate just a list of technologies without any further comment as this is outside the scope of our analysis.

- WAMS (Wide Area Monitoring Systems).
- FACTS (Flexible Alternating Current Transmission Systems).
- Super conducting current limiters.
- Super conducting cables.
- Phase-shifting transformers.
- Underground smart cables.
- Electricity storage technology.
- Smart metering, and Demand Response supporting equipment.

The research plan also incorporates a detailed governance framework, which has several objectives. There is a need of monitoring the efforts as the funding will be charged to the users of the grid; the activities will be carried out by a large pool of actors (Universities, Utilities, consultants, TSOs, Research Centres, manufacturers) and it is fundamental to award excellence choosing the best; it should be provided that the results will be integrated in the TSOs activities and it should be guaranteed that the research should always be in line with the European Energy Policy objectives and discussed in a transparent manner with all the stakeholders.

5.3.3 ENTSO-E Ten Year Network Development Plan

The TYNDP had its first version in mid 2010: it was submitted ahead of time by ENTSO-E with the purpose to gather some essential information, but without fully developing all the tasks indicated in the Third Legislative Package, which are the following:

- Modelling of the integrated European network.
- Scenario development.
- European Generation adequacy outlook.
- Assessment of the resilience of the system.

Our analysis will focus then on what can be considered as the intermediate results of the 2010 publication and on the scenario outlook that will converge on the 2012 edition.

Investments in the 2010 TYNDP

This part was developed with a bottom up approach asking to all the TSOs to report investment plans and investment needs at short and medium term. These were analyzed by TSOs at regional level with one country possibly participating to more than one region. Regions are then determined as areas sharing issues that have to be tackled together.
France for example is in three of the seven clusters with very different implications: the North Sea (including Norway, the Benelux and the UK) as being indirectly interconnected to the exports of Norway; the Continental Central South with Italy and Germany given the large amount of cross-border exchanges and Continental South West with the Iberian Peninsula. The connection between France and Spain are clearly a determinant of the development of the Iberian Market.

The issues driving the clusters are the following:

- Renewable integration in the North of Europe: this deals with large deployment of offshore wind power and the issues related to connection, inland grid reinforcement and need of increased balancing.
- Renewable integration in the South of Europe: the deployment of solar and wind in the Iberian peninsula; again here the focus is on grid reinforcement and balancing. The need for an increased interconnection with France is indicated.
- Baltic States integration: the plans for integration of the three Baltic states into the European Market. The new interconnections with Finland, Sweden and Poland will also induce an internal reinforcement plan.
- North-South and East-West flows: this cluster has very diversified targets. We can quote: the integration of increasing flows due to wind power in North Germany; the expansion of the interconnected zone to Turkey and the Ukraine; the increase of hydro capacity in Austria and Switzerland; the deployment of new generation

capacity in Bulgaria, Hungary and Croatia. The evolution of the generation capacity and the new possibilities of interconnection with currently not synchronous areas will have then a huge impact on the investment needs.

- Connection of non RES generation as 100 GW is planned to be developed before 2020.

It is useful to quote also some data on investments till 2020. The data reported (length of new or upgraded connections in km) consider only the projects which have a European impact, counting then not only cross-border, but also national projects which are relevant for transits.

DC links	9600 km
AC Lines	32500 km
of which AC Lines 400 kV	*29600 km*
Total	42100 km
of which in mid term	*18700 km*

The 400 kV lines represent the most efficient technology that also does not have compatibility problems with the current system. The DC links are basically all sub-sea or underground cables.
Given that the ENTSO-E network consists of 300000 km of lines, the new investments represents 14% of the existing grid.
A classification of lines according to the impact on the three pillars of the European energy policy is also provided. As each investment could address more than one pillar the total number is far greater than 42100 km.

Security of Supply	26000 km
RES	20000 km
Integration of European Market	28500 km

In terms of costs, estimates are given for projects completed by 2015 with a total amount ranging between 23 to 28 billion €, a figure that highlights the future challenges for the sector.
An interesting remark is how, given the restrictions imposed on new lines, unitary costs could often be much higher than in the past. For example, underground DC cables can cost up to 8 times with respect to a 400 kV overhead line.

Scenario Outlook and Adequacy Forecast

The Scenario Outlook and Adequacy Forecast (SO & AF) 2011÷2025 is the first part of the exercise leading to the 2012 TYNDP.
The purpose of the scenarios is to support the analysis to be made on investments and markets performance. It also has to assess the generation adequacy both at a general ENTSO-E level and for the six regional areas. In terms of adequacy there is also a monitoring exercise made on national plans sent by TSOs.

With respect to the 2010 plan that had two bottom up scenarios A and B (conservative and best estimate) the 2012 plan includes also a top down approach (EU 2020) that is based on the on the National Renewable Energy Action Plans (NREAPs).
These were submitted by most European countries during the summer of 2010 showing the process towards the 20/20/20 strategies adopted by the European Union.
The outlook contains also a series of estimated indicators to assess the contribution of the power sector on the above targets, reflecting the impact of efficiency measures on electricity consumption, the impact on CO_2 emissions and the RES share in the overall supply of electricity.
The data collection was estimated for the years 2010, 2015, 2016, 2020 and 2025, with as reference points two days in the year, one for winter and one for summer, the 3rd Wednesday in January at 7 PM and the 3rd Wednesday in July at 11 AM.
In the report there are comparisons between scenarios in order to have an idea on how generation adequacy and investment needs will look under different conditions.
Comparison between scenario B versus the EU 2020 shows the differences between the investments considered by TSOs with respect to those necessary to meet the Political Target and the NREAPs. Comparison of scenario A with scenario EU 2020 instead compares the investments already decided by TSOs.
The Scenario B and EU 2020 will be those used in the studies leading to the identification of the necessary grid developments and adequacy assessments.
The overall results for the European Union show how the EU 2020 scenario ensures generation adequacy reaching:

- a 9.6% reduction of consumption of electricity due the introduction of energy efficiency policies;
- a level of consumption of RES generated electricity equal to 36% of the overall demand;
- a CO_2 emission reduction between 26 and 57%.

Given these favourable perspectives the challenge ahead is to confront these figures with possible transmission arrangements so as to choose the most efficient among the possible options.

5.4 Concluding remarks

The purpose of this chapter is not to draw conclusions since the current situation can be considered as a period of transition.
We covered two main aspects: some key institutional issues on the role of the TSOs in the European Electricity Markets and the first steps of the implementation of the Third Legislative Package.
On the institutional issues we have presented the options of organizational models of TSOs at European level and the options in terms of cross border congestion management. These two topics have been under discussion for more than ten years and have been the concern of many serious studies that are reflected in our survey, but neither of them has been the subject of a thorough analysis done at the right institutional level and with the participation of all the stakeholders.
Then the only recommendation could be to decide the level of priority in the reforms agenda and an appropriate framework for decision making. The process does not seem

easy as there are very different views among stakeholders and researchers, with an industry in general reluctant for reforms and studies showing the benefits of radical changes.

On the implementation of the Third Package the current situation is still at the really beginning and then there is not enough evidence to evaluate the results.

The proposals that have appeared so far are extremely encouraging and they are written following all the good principles, but they clearly present a great risk in terms of implementation.

The weakness is the lack of centralized control that could be necessary to regulate the European Market. The question is then to see if the interest of the involved stakeholders will be sufficiently aligned so as not to create conflicts or inefficient solutions as a result of an excessive degree of compromise.

6 Electricity security of supply with increased presence of distributed generation

In [5] we provided an overview of recent advances concerning Distributed Generation (DG). The concept of DG since the first planning of the SECURE project has been rapidly evolving and now it is basically encompassed by the term Smart Grids. We did not deal with the whole Smart Grid domain, but we limited ourselves to the economic and regulatory aspects related to the distribution network, including, besides generation, also the issues related to customers' participation.

The focus is on trying to clarify what are the main implications of deploying new technologies and how the management of the power system should be adapted; it is quite striking, but electricity markets have been very slow in terms of innovation, due to a lack of an adapted institutional framework.

Our analysis is not specifically framed in terms of Security of Supply as security (in all its dimensions) cannot really be separated from what is the ultimate goal of an efficient design of the power system. Also being our approach mainly institutional, the focus is limited to the European market, which at the moment is very interesting as there is a concrete effort to define a common approach, aiming at setting standards in terms of technology and regulation.

As mentioned above, our survey covers a subset of the area that is called Smart Grids, which relates to the distribution network. For what concerns generation we clearly refer to DG, which is connected to medium and low voltage networks. The technologies used are RES (Renewable Energy Sources such as photovoltaic, small hydro and wind, biomass and biogas, etc.) and Combined Heat and Power (CHP).

The perception of DG has rapidly evolved in recent years; initially the principle[20] was that the system should absorb all the generation produced without any attempt to control both the generation patterns and customers' demand. In terms of support mechanism this has been implemented by a system of flat feed-in tariffs, which give a fixed compensation for the electricity produced and impose to network operators to give priority of dispatch. The main driver of the feed-in tariff system is the need to create a favourable and stable investment environment in order to deploy new technologies. As governments have often granted fairly generous schemes then these programs have been quite successful, but quite expensive in the end for consumers.

The main problem with the feed-in tariffs is the complete separation from the market and the development of the network. In an efficient liberalized market electricity should be paid taking into account where it is produced and consumed and when it is bought and consumed.

As a matter of fact, generation, especially if installed near customers, can be considered as a substitute for the transmission and distribution networks; this is valid if the electricity is consumed in the same area where it is produced.

In order to obtain an efficient deployment it is then necessary to take into account local demand when connecting new Distributed Generation, as the real value of the electricity could be increased by the avoided investments in the network. Ideally then there should be some form of compensation for the investments which bring benefits to the system.

Nonetheless demand does not have only a locational component, but there is also a time factor as generation might not be always available to satisfy demand. This is clearly the case of RES as these are not controllable, but it is also valid for CHP as electricity

[20] This principle is the most used today, but the trend is to find more advanced compensation schemes.

generation has to follow often heat demand in order to be profitable. Additional profitability can also be obtained by offering services to the network such as balancing and ancillary services.
The Smart Grid denomination refers then to a system that is not passive with unidirectional flows from top to bottom, but instead it allows for a wider type of control and investment decisions based on all the available information. The main driver towards change is the increased possibility offered by recent technologies to acquire more precise data and exchange information in real time. It is then possible to manage large numbers of generating units and customers at the distribution network level in a way that resembles transmission, or to use a more dynamic approach where there is a constant interaction with the generators and the system is optimized in real time.
We can see immediately how Security of Supply (SoS) is clearly an essential feature of the DG and Smart Grids, which introduce alternative ways to increase the capacity of the network and allow the supply of services, which are used up to the real time balancing of the system.

6.1 Key Issues

Given that a power system has deeply interconnected components, there is not a precise logical order to present our topic; we will then introduce a series of issues and reconcile them at the end highlighting what messages should be retained.

6.1.1 Hosting Capacity

In electricity systems the transition to more innovative solutions cannot be radical, it has to be progressive as previous investments have to be "phased out". In terms of DG then it is important to understand what are the stages leading towards an increased penetration, this as the system does not have to necessarily undergo a complete revolution from the beginning.
The concept of "hosting capacity" defines the rate of penetration of DG a distribution network can handle; this is very important in order to understand at what level it is absolutely required to upgrade the type of control of the system.
Following recent studies[21] the key parameters to be considered in order to determine "hosting capacity" are the coincidence of load and generation, the homogeneity of the HV - MV substation feeders in terms of location of load and generation and the voltage control margins.
The most intuitive is the first, coinciding generation and load basically cancel out in terms of impact on the network; what can be envisaged are control strategies to reconcile load and generation through control actions. In terms of voltage there are options: if we consider a medium penetration, especially in urban networks, voltage can be set according to the coincidence of load and generation. In the case of rural networks, instead voltage should be adjusted dynamically according to the operating conditions. The first of the two approaches is of the type "fit and forget", the second is called "active management"; the two terms are self explanatory: one is similar to what has

[21] www.eudeep.com (2009).

been used in traditional networks, the second is a more innovative solution, which is particularly interesting when feeders are very long and covering sparsely populated areas. If the penetration ratio dramatically increases, then an active management approach is always necessary; this could imply not only a dynamic control on voltage (soft active management), but also a direct control of generation (hard active management), which could lead, in extreme cases, to curtailment of units. Demand Response can also provide a relevant contribution in such a case.

The concept of "hosting capacity" gives a sort of roadmap of the evolution of the system; in the first stages of penetration the type of intervention of the DSO (Distribution System Operator) in terms of operations is limited; as the percentage increases, the system has to be controlled differently requiring more innovative solutions. In this transition one characteristic is that the role of all the actors would be evolving: DSOs will have to act as TSOs with real time operations and demand and generation should be flexible taking into account the needs of the system.

6.1.2 Network Value

One factor that greatly complicates the deployment of DG is its impact on the network, especially since it is not straightforward to evaluate; moreover, the impact can vary according to the type of network and the network conditions can be both positive and negative.

As there are different actors involved in the deployment of DG, then there is a clear issue in terms of cost allocation; if the impact of DG cannot be assessed, then actors will not have the correct incentives with respect to investments in DG.

A simple example: if a DSO is compensated only for the electricity transported on the grid then it will not have incentives to promote the connection of DG, which will probably generate only additional costs.

In the EU DEEP project, a methodology has been developed to assess the impact of load and generation in a low voltage distribution network. Given the nature of our survey it is not necessary to go through the method, but rather we should highlight certain features, which are useful to understand better the issues raised by DG deployment.

One of the key conditions is to know independently the characteristics (called footprint) of load and generation. In order to achieve this it is necessary to set up an adequate smart metering system, which should automatically collect the data in short intervals. These should be analyzed ex-post in order to assess the impact on the different network components during the yearly peak conditions of each element.

For example, in the case of a micro CHP in Northern Europe, there is a correspondence between the peak of consumption, which is during winter when there is a high demand for heating, and the generation. On the other side PV in Northern Europe will be mostly effective in summer, when the system is not under stress. This means that only micro CHP could receive a compensation as they contribute as a network replacement.

Conversely a micro CHP in Southern Europe, being efficient during the summer peak generated by air conditioning, would not be remunerated.

The assessment of tariffs is a way to understand the overall trend in the cost of the network. As we have seen the impact of technologies can greatly vary according to local conditions, the indication is that policies should be set in order to capture these

differences also in order to promote an efficient use of energy, installing units where they are the most profitable.
Unfortunately the deployment of DG could increase network costs, which is then a fact that should be taken into account in terms of system planning.
The scope of tariffs is then to induce actors to take optimal decisions, which progressively would reduce the overall costs of the system.
If the tariff mechanism is not set appropriately, then the main effect is to induce DSOs to try and reduce the number of connection of generators, given that an increasing amount of DG could deeply affect their profitability.
DSOs are the central actors of the system, which should promote and not obstruct innovation and should not see DG as an obligation, but rather like an opportunity to increase their profits[22].
Security of Supply in this context is represented by the lowering of the cost of network infrastructures, or simply to have more generation connected with lower investments.

6.1.3 Services Value

This is a topic that has recently surfaced and is rapidly evolving as further studies are carried out in order to allow TSOs, DSOs and service operators to take full advantages of the flexibility offered by DG (and Demand Response) to provide balancing and ancillary services. It is easy to see how this is a radical change from the feed-in tariffs system as here DG interacts directly with short term and even real time operations.
Electricity markets differ in their design especially when dealing with balancing and ancillary services. In general the trend is to use market-based methods for the provision of such services. DG, using the adequate provisions, can offer these services; we mention provisions as markets are not normally designed to interact with small units and some rules could block the participation of DG.
It is then necessary to evaluate what type of market design should be the most effective to capture all the values of DG. The driver should always be efficiency and not a fixed objective like deployment targets. Also market design should induce generators to provide more innovative solutions in order to achieve market participation at a lower cost.
There are two main concerns in this area.
One is the size of the units, which are allowed to participate; increasing the number of units could add excessive complexity to the market.
The second is a general concern for the TSO on the reliability of small units in the provision of services dedicated to emergencies. It is a delicate interaction as these services are the last resource available before having serious accidents.
It should be reminded that there is a wide gap between these procedures and what was implemented before liberalization. TSOs at the time were the owner of the resources and then there was full coordination and a common development of activities.
Currently these operations are carried out through contractual arrangements, which on one side do induce a more competitive attitude in generators, leading them to reduce the costs of the services, but also clearly cannot duplicate the level of trust and interaction among people working for the same company. Still as these are feasible options, it makes sense to develop methodologies that could overcome these issues.

[22] This topic will be resumed in the section dedicated to Regulation and Innovation.

6.1.4 Aggregation

The first perception of DG was that of a system where customers could participate directly to the market at an equal level with larger entities. This created many concerns as it would have had implied an extreme level of complexity. Even if this would have been technically accepted, it did not seem efficient from an economic point of view. As a matter of fact, in order to effectively participate to the markets an actor needs a series of skills and a considerable amount of time spent analyzing the available information: these are not justified for small units or small consumption as the savings would not compensate the efforts. It was then necessary to find a rational way to exploit the existing potential.

The principle of the solution was to have an agent acting as an intermediary between the market and small operators. The concept is not new and it is being applied widely in other contexts; basically an agent handles the resources of its clients for a percentage of the profits[23]. The intermediary, having a large number of clients, spreads the fixed costs necessary to take optimal decisions and to establish the interaction with the centralized market.

In the DG literature this concept has taken the name of "aggregator". The word comes from the concept of aggregating the functions of several generators, with the possibility of offering a unique supply profile.

Our survey is based on the results of two European FP projects (EU DEEP and Fenix), whose main focus was on providing integration of DG and Demand Response through aggregations[24].

In the previous sections we did not go into any specific description of the system, we do it at this stage as aggregation is basically the way forward and then these are the challenges which companies and institutions will have to face in the coming years.

The concept of aggregation is to link medium and small generation and customers ranging from small industrial down to residential, in order to coordinate them with the electrical system and the various electricity markets.

One major shift with respect to a classical system is that network operators can interact with these types of generation and demand. Previously, operators could passively receive only aggregate information and could not then send any type of signal in order to modify their behaviour[25].

The aggregator can also be a provider of services to his customers in order to optimize their energy performance.

The following is a list of activities, which can be carried out by an aggregator:

- buying electricity from DG;
- selling electricity into the centralized market (trading);
- selling electricity directly to customers (retailing);
- providing balancing services to his own customers;
- providing balancing and ancillary services to TSOs and DSOs;
- providing maintenance to the units under its control;

[23] There are many possible examples of contractual relationships, besides percentages of profits.
[24] www.fenix-project.org (2009).
[25] For example customers in emergency situations could be curtailed, but without knowing their actual individual consumption.

- heat supplier;
- providing support to generators in order to receive subsidies (feed-in tariffs, green certificates, support to CHP, etc.);
- implementing Demand Response actions.

From the list we can see that there are other additional business possibilities; these derive from the fact that the aggregator can exploit the relationship with his customers in order to improve their energy consumption.
It all depends on the type of information, as this can be used to provide more than one type of service.
This information it is not only used on a client-by-client basis, but the optimization is carried across customers as different profiles can be combined in order to obtain a better overall performance.
A very intuitive example can be made with balancing: if generators have imbalances in different directions then in the aggregated outcome these would to a certain extent cancel out. If these had to be considered generator by generator, then imbalances charges would be higher[26].
The above list helps us also to understand what type of company could operate these services. First it is important to mention the fact that not all these should be performed by the same company: in order to reach profitability, some companies could prefer to specialize.
Also, it is possible to have some of the services outsourced as monitoring and coordination of external activities is often feasible; what seems important is rather to have the customers interacting with a single company in order to reduce the level of skills and understanding on the customer side.
There is no predetermined organizational model for aggregators, while some of activities share competences and information related to the retailing business (basically a knowledge of the market conditions and the data of individual customers).
Then there are more technical tasks like those related to installation, management of the units, analysis of the customer’s energy needs, which are areas covered by the so-called ESCOs (Energy Services Companies).
What should determine the choice is the characteristics of technologies the aggregator must deal with and the characteristics of the customers.
Sometimes even if the range of activities is the same, the relative profitability of each of them could greatly differ, justifying different organizational choices.
An ESCO can for example have simplified trading activities given a limited flexibility of the units available and instead concentrate on very small units, where, given the large numbers of customers involved[27], more complex maintenance and installation tasks are required.
For our purposes a general message that can be sent is that the business is not necessarily aimed at small or medium sized companies; there are many characteristics which can take advantage of large economies of scale.
If we take into account all the possible interactions between the different activities, then it is possible to infer that large companies with several lines of business could have a clear advantage.

[26] There is no standard way to pay for imbalances and charges are often calculated ex-post according to the system conditions.
[27] When the units are small the number of customers has to be high in order to reach profitability.

These considerations are quite intuitive, but support a vision of a system which exploits decentralized resources in terms of small generation and customer participation, without at the end fundamentally changing the type of business actors involved.
In terms of policy this is not negligible, as it implies policy actions that should raise public awareness given that the customers participation is essential, but at the same time it requires the creation of a sound business environment for larger actors, who could be those who have in many situations the best skills to address these markets.
One crucial component of the aggregation business is the type of *contractual conditions*, which could be established between the aggregator and its customers. This topic is extremely relevant as contracts are the instruments that should allow and induce actors to take efficient decisions.
The challenge here is given by the number of actors and the complexity of decisions involved, which are factors pushing towards a general simplification of the contractual relationship. Still the problem is that simple contracts have the possible negative effect of not giving the adequate incentives.
Contracts depend on the technical configuration of the system as what is offered by technology can be fully exploited by actors only if there is a compensation mechanism allowing them to recover the benefits.
The main element of a contract is the ability to measure the effects of the actions taken by the parties: in our context this is offered by metering. It is then the type of metering that determines the relationship between the aggregator and his customers.
Another technical element is the type of control that the aggregator can have on the generating units or on customers's load.
A third element is the type of transmission of information, which is possible between the aggregators and the customers.
With these three dimensions it is possible to cover most of the contractual relationships.
It is better to work through simplified examples to give a bit of the intuition of what can happen in practice.
An aggregator can notify a day in advance[28] to customers a compensation scheme at which it will buy electricity. Then the customer can decide to modify his/her own consumption in order to sell to the aggregator during the hours when it is more profitable. Customers have to calculate the price offered by the aggregator with respect to the costs incurred to diminish their consumption. For residential customers it will be the value created by the discomfort, for a business the cost of stopping or altering the type of activity carried out at that moment.
Here we see that transmission of information does not require a very rapid decision by the customer. There is no control of the aggregator on the customer as he/she can decide to accept or not to supply electricity.
If we reduce the interval of notification to a very short time, then this translates into real time pricing or small customers reacting directly in almost real time to the evolution of prices of the Power Exchange. Clearly in order to implement this option it is necessary a specific technology to allow the customers to receive the price quotes.
A different contract may entail an aggregator controlling the consumption of the customers with no or very short notice. For example an aggregator could reduce slightly air conditioning or switch off some of the lights for a short period of time in office buildings. The advantage of such strategy is that, if applied at a large scale, it can have a significant impact by allowing intervention in emergency situations, without significantly affecting the comfort of the customers. The important factor is the

[28] This could be a function of the realization of the prices in the Power Exchange.

complete control of the aggregator on a part of the customers' consumption that allows the aggregator to be able to offer services requiring a fast response.

The contracting theme can also be seen in terms of system architecture as the control of the system is determined by a framework of contractual relations between TSOs, DSOs and the aggregator.

This concerns the long term evolution of the system where responsibilities for managing the system could be shifted also according to different possibilities in terms of control and transmission of information. An example could be the option to have parts of the system run in a sort of isolation with respect to higher level distribution and transmission system.

This idea, labelled *Microgrids*, is an extreme concept of aggregator as there should be a full integration of all generation and load in these separated areas under the control of the aggregator, which also would have different responsibilities in terms of system management, as the role of the TSO and DSO would be limited to provide last resort security.

An important implication of contracting concerns how a company deals with customers and what are the customers' needs and requirements when faced with the possibility of choosing to install DG and Demand Response on their premises.

In order to assess the potential diffusion of these technologies it is necessary to take into consideration the level of acceptance as the form of interaction required is fairly direct, affecting the personal habits of the customers.

This is increased by the aggregator solution as it requires a constant interaction with the customers.

A list with some examples:

- Possible concerns of reduced safety as the new technologies would interact directly with existing installations.
- The effect in terms of the remote management of infrastructures installed on the customers' premises should be taken into consideration.
- Customers should fully understand the implications induced by the flexibility, being the main profitability driver, on their daily life.
- As the aggregator is an intermediary, it should be transparent what are the drivers of his compensation. The customer has to understand how profits are shared between himself/herself and the aggregator[29].
- If there is the possibility of penalties, as customers could not respect their commitments, these should be carefully explained.
- The ownership of equipment could be either of the aggregator, of another company or of the customer. The three cases have different implications, which must be taken into account when investments take place.
- The responsibility in terms of maintenance and repair is also a crucial aspect, which should be dealt with taking into account customers' characteristics.

As an overall remark we can notice how the aggregator solution implies a remarkable involvement on the customer side, which also should require a change in mentality with respect to the current habits in terms of energy consumption.

[29] The customer could perceive the aggregator as business partner, then additional transparency could be requested.

These examples are interesting also from the point of view of Security of Supply, as they deal directly with the personal security of the customer. Along the same lines, from a sociological point of view, customers could be induced to participate as they feel some social obligations as they realize that their actions have an impact that goes beyond what can be perceived at personal level.
The concept of aggregator is then the future framework that must be further developed to increase an efficient penetration of DG (independently of the evolution of generation technologies) and Demand Response. It has several implications for Security of Supply: it clearly improves energy efficiency allowing customers to better exploit their potential; it allows a wider range of methodologies to be used for balancing and ancillary services, increasing the resiliency of the system to emergency conditions and lays the foundation for a more decentralized use of the system based on parts of the system, which could operate basically independently of TSOs and DSOs (Microgrids).

6.1.5 Regulation

Regulation is an integral part of the DG/Smart Grid story, the main reason being the type of interaction between generation and the grid.
As we mentioned above, it is not straightforward to separate the type of externalities created by DG on the distribution network and vice-versa; from the regulatory point of view this translates into mixing a regulated monopoly and generation, which is subject to anti-trust regulation being a competitive sector.
The difference with large generators is that the role of the TSO is in a way more "neutral" and then the impact of the actions of various actors are easier to separate. For large generation networks, regulation can be seen as side constraint, while for DG regulation is a an essential part of the business models.
Regulation can affect DG value in three areas:

- Market design or the rules determining market participation.
- The support, which can be received as green technologies or energy efficient technologies.
- The value brought as network replacement.

Market design is a topic brought by the liberalization process, it is a still ongoing process as it is not easy to find rules able to fully capture all the possible characteristics of electrons. Also it will adapt in time to new technologies especially on the communication technology side.
DG in this area is a newcomer as the markets have been designed for large generators and it is then a challenge to make them compatible with smaller units.
In this respect the aggregator is an interesting solution as from the system point of view, it can be perceived as a large generator, with the consequence that the market design does not need major modifications with respect to the current arrangement. A necessary condition is that the aggregator has the contractual relationship with the TSO and DSO, which means that it takes full responsibility for the actions of its customers. If this is not the case still the fact of acting as intermediary helps the customers to deal with decision and circumstances, which might be too complex to manage.
Support mechanisms are a fundamental part of the compensation of DG and they should reflect the externalities provided by these technologies, which we know not to be

competitive otherwise (i.e. in terms of cost per kWh only). Incentives can be collected for RES production and for energy efficiency (CHP); these mechanisms in Europe vary from country to country and the result is that it is then not possible to judge what are the best technologies on the basis of penetration statistics as the investment conditions are not similar.

Subsidies are also calculated in order to create a critical mass of business working with a certain technology guaranteeing a period sufficient to recover sunk investment costs.

As externalities are not easy to calculate there are heated discussions on the type and quantity of support; as they cannot be avoided, it is then necessary a continuous process of analysis in order to develop methodologies that could reveal the real benefits.

We have already discussed the *network replacement* properties of DG and some properties that should be reflected into tariffs. In this section will further expand the analysis addressing the overall regulatory framework for DSOs.

It is intuitive that if it is optimal to invest in DG rather than in network components, then the compensation for DSOs should not be based on mark-ups on network investments. The focus should be on the overall output/performance provided by the DSO, including then parameters that should be taken into account for the connection of additional DG.

The overall objective is what we have already stated that is to develop a network where DG is connected in the areas where it is most efficient, taking into account then the network configuration and customers characteristics. The problem is a certain asymmetry of information as DSOs have superior information on the network and its possible expansion. It is then hard for an outsider (in this case the regulator or an investor) to estimate what is the real value of the investment in DG.

To describe the basic principles of the relationship DSO-DG developer we can define the investments according to a classification used in basic Economic Theory. Network replacement is a case of *substitutability* between different goods, as the DSO does not need to expand the network as the demand is satisfied locally by the new generation.

We can find instead *complementarity* in terms of network expansion. There are circumstances in which the first units connected in an area could require large investments, which would be later used by other units. It would then increase the chances to have the investments being made if this would be taken into account or if the first units would not have to bear all the initial charges taking into consideration the possible evolution of the network.

As we mentioned, there are informational asymmetries: in practice it is not possible for the regulator to set adequate tariffs reflecting the costs of connection and the advantages of avoided network replacement as the regulator does not have precise information on the actual costs[30] and does not have an adequate estimate of future growth in demand[31].

The DSO has better information on these costs, clearly with some uncertainties as network expansion is always being determined in a probabilistic way.

Unfortunately the incentive of the DSO is to overstate the costs incurred for connection and diminish the advantages it could receive by DG in order to obtain higher profits.

In view of the above, a possible regulatory solution should then be to compensate the DSO on overall efficiency objectives and not to allow it a return based on each connection.

The DSO should be allowed to determine up to a certain extent the charges for DG investors in order to induce them to invest where it is more convenient.

[30] We have to remind that costs vary according to location and customers consumption behaviour.
[31] To be used in the complementarity case.

This could raise controversy as there would be a possible lack of transparency on the DSO side as there could be questions of how these are determined.
Still this solution seems preferable: the main reason is that it can capture better the need to allow for a long term evolution of the system, as these technologies require heavy investments, which cannot be captured by simple cost per unit analysis.
This approach could be used to promote a sustainable regulation, in the sense that regulation should keep pressure on costs reduction, but also consider an horizon that should go beyond possible short term managerial interests.
On these lines, support for innovation is also a relevant topic. DSOs have traditionally operated in fairly simple systems, instead DG and Smart Grids require an implication in research and innovation also for DSOs.
Being a monopolist, and thus not subject to competition, the DSO does not have naturally many incentives to innovate; this is even truer if the innovation from the society's point of view entails substantial changes and significant uncertainty as to the results and especially the time horizon necessary to achieve them.
It is then a regulatory concern to provide a framework under which the DSO would perform these activities and be adequately compensated for the effort.
Above we have suggested the possibility of output regulation; however, when it comes to innovation, research and demonstration projects, it is hard to define an output as these activities have a high risk of failure.
Thus the solution would be more input driven, leaning towards mechanisms inspired by those used for financing standard research. It would also be useful then to favour the interaction with external experts and award compensation through competitive tendering.
As in standard research, differences in financing methods should be based on the type of activities, considering that some imply more risk than others.
Regulation has also an important role in standardization as this is often a barrier to cost reductions. Being Europe in principle a single market, there should be an effort to avoid unnecessary costs for companies to adapt to local technical standards.
This consideration is not limited to components, but also to all the regulatory measures, which as we have already noticed, can have an fundamental impact on the profitability of a business model.

6.2 Security of Supply

The aim of this chapter has been to give an overview of the current and future drivers of Distributed Generation and the part of Smart Grids related to the distribution sector and their role in the evolution of the system. We then highlight here the connection with the theme of the SECURE project, i.e. Security of Supply.
From the customer's point of view, an important driver is to guarantee himself/herself a level of reliability superior to that offered by the system. This is very common for example for hospitals and factories where even a small alteration of the quality of service could imply great damages to the production cycle.

If we take this to a more "philosophical" level, we can notice how networks offer in general extremely high level of reliability, which are not only the effect of the skills of the workers, but mostly of massive investments paid by all the customers.

In the past this was a necessary solution as it would not have been possible to offer a tailored level of reliability to each customer.

With the current technology this is an option both at the individual customer level or in a near future for an entire area.[32]

The point of the argument is not really to decrease the actual overall standards, but to evaluate if improvements should be generalized or the customers should choose individually for a higher level of reliability. The point is to give the customer the option to pay for the services he/she really needs.

We can see how the aviation industry has pushed this concept offering extremely low prices and offering travellers the possibility to acquire additional services, which before they were taken for granted. This is all possible given the technology, which makes detailed bookings extremely easy. The same principles could be applied to the electricity sector as the supporting technology is already available and ready to be widely deployed.

The principle that customers receive something that they do not really need, can be seen in contracts where an operator buys the option to degrade the service offered or curtail the supply of electricity. For example a customer would be compensated with a reduction on his/her bill. The interest for the operator could be various as it could reduce with such action either its operational costs (like ancillary services) or its equipment costs as it can delay the expansion of the network.

Thus new technologies allow to respond more efficiently to the customers' needs and preferences by offering them the required level of provision of services, and by reducing their electricity bills.

In terms of policy recommendations it is important to remind that customers cannot be totally pro-active: given the complexity of the system, independent initiatives to increase their safety would often be extremely expensive. Such options should be necessarily provided by utilities and network operators with the support of regulatory authorities.

The solutions have then to arrive from the top and the aggregator model that we have presented is a clear example, where the customers needs to be put in a simplified environment in order to use efficiently their potential in terms of generation and flexibility.

We have shown also the effect of reducing network investments, with a decrease in the overall costs of the system.

The substitution of networks can also reduce the risks of accidents of those areas that cannot expand their network connections[33] and have an increase in demand. Then DG and Demand Response can be crucial to avoid emergency situations.

DG can provide balancing and ancillary services, which are the services needed for emergencies. These can be provided especially with the help of the aggregator, which has the role to facilitate the interaction with the different markets and network operators. For a system under stress even small quantities of flexible generation and demand can avoid accidents, so this feature of DG is extremely relevant and can be one of the driver of its future diffusion.

We have seen that DG is composed of RES and energy efficient technologies; this implies that DG expansion would bring a reduction of imports and a reduction of

[32] We refer to the Microgrids example.

[33] For example, due to environmental constraints.

consumption of imported primary fuels. These are not major effects at the moment, but they could increase their importance according to the level of penetration.

In Europe, electricity has been considered as a right for the citizens, but there can be situations where remote locations imply excessive investments with respect to the type and quantity of demand served. DG can in many circumstances solve these issues, allowing customers to decide the level of service they require. Islands fall into this category as very often they have a very peculiar demand profile, being frequently tourist destinations with huge differences in consumption between summer and winter. Then a more flexible system with investments driven by local demand can be a better solution, allowing to follow the growth dynamics of local communities.

To conclude we can assess that DG, together with Demand Response and Smart Grids are technologies which can have an impact in the future European electricity system as they are very much in line with the current EU Energy Policy objectives and as they are rapidly becoming compatible with the existing market.

Our survey had the objective to give an overview of what we consider the issues, which should be taken into consideration from a policy perspective.

Given this general framework we have pointed out then what are the implications in terms of Security of Supply; we can notice that even if this is not the main driver there are many advantages brought by DG in terms of security.

Clearly the importance will raise according to the available capacity and the technologies that will prove most successful in the coming years. This holds not only in terms of generation, but also in terms of networks, metering and communication technologies, which are key factors to fully exploit the potential of DG.

7 Policy recommendations

Electricity security of supply has implications along the whole chain, from generation, to transmission/distribution, to demand.

As far as generation is concerned, the main issue is to ensure both in the short and in the long term its *adequacy*, i.e. its capability to keep the supply/demand balance (taking into account network constraints).

Generation adequacy is mostly related to the availability of an installed capacity sufficiently larger than the expected peak load, i.e. the availability of a sufficient *reserve margin*. Nevertheless, the sole amount of installed generation capacity is not sufficient to ensure adequacy, since in addition the generation set must be well *adapted* to the load, as well as to the increasing penetration of intermittent renewable sources: this means that the composition of the generation set in terms of base-load, mid-merit and peak-load power plants (characterized by different operating flexibility), as well as in terms of dispatchable and non-dispatchable ones, must be correctly balanced.

In this respect, it is widely recognized that electricity price signals coming from the market are, by themselves, not sufficient to ensure generation adequacy, mainly due to informative asymmetries and to lack of sufficient competition that make market players unable to collectively obtain an "optimal" development of the generation set, both in time and in space (i.e. in terms of location in the network).

Moreover, the often long and uncertain permitting procedures, as well as investors' risk aversion that makes them wait until they can be pretty sure of the profitability of new investments, introduce significant delays between the moment when a new power plant is needed and the moment when it becomes available.

This could cause the so-called *boom-and-bust cycles*, where periods with high reserve margins and consequent low electricity prices that do not incentivize new investments, due to subsequent progressive load increase and to decommissioning of old power plants, alternate to periods with low reserve margins (therefore with low security of supply) and consequent high electricity prices, that could lead to a new wave of investments, thus restarting the cycle.

To tackle the aforementioned problems, in several electricity markets worldwide, regulatory authorities, under the approval of Governments, defined and/or implemented specific intruments such as tendering procedures for new capacity, capacity payments, capacity markets/obligations, call options, etc.

We recommend the implementation of such instruments to push investors to pursue the "optimal" development of the generation set and to avoid the above mentioned capacity "bust" situations, but we also recommend to rely only on "market based" mechanisms able to get the most efficient solution through competitive procedures (e.g. fixed capacity payments administratively defined should not be taken into account).

According to Regulation (EC) no. 714/2009, Transmission System Operators (TSOs) are in charge of assessing the present and future adequacy of the power system both at the national level and, through ENTSO-E, also at the European level. In doing so, TSOs should not only "passively" try to envisage the future generation development according to market players' investment behavior, but they should support the implementation of the aforementioned adequacy instruments being "proactive" and providing a technical evaluation of how much new generation capacity of the different types is needed, when and where (the location in the network is very important), on the basis of scenario

analyses concerning in particular demand evolution, intermittent renewable sources penetration and network development.
Of course, it would be desirable that all this process be coordinated and harmonized at the EU level to increase its effectiveness and to avoid market distortions.
Furthermore, it must be taken into account that a generation set that is adequate in terms of installed capacity and in terms of composition could again be insecure if its fuel mix is not sufficiently diversified, so that a large amount of capacity could become unavailable in case of a fuel supply shortage (this kind of risk has been analyzed in [2] and in chapter 3).
As for the most interesting remedies from the policy point of view, as far as the power system is concerned, the most obvious remedy to a fuel supply shortage in the long term is to pursue a greater primary source diversification in the generation set. In this respect, a further sustainable development of Renewable Energy Sources, supported by Directive 2009/28/EC, is a must not only for security of supply, but also for several other reasons. Nevertheless, as above mentioned, RES intermittent nature requires an adequate backup capacity, made of conventional dispatchable power plants.
In fact, the objective of a greater primary source diversification could be reached using the same above mentioned regulatory instruments concerning capacity adequacy; of course, the highest political levels responsible for the overall energy policy are in charge of the quantitative definition of the objective itself: in this case TSOs could only play the role of consultants for technical aspects concerning the implementation of the objective and its impact on system adequacy.
Another important remedy to the risk of fuel supply shortage concerning the power system is the increase of cross-border transmission capacity, so that foreign power systems can help more the country affected by the shortage: we will be back to this later on, when discussing specifically of transmission issues.
Of course, effective remedies to a fuel supply shortage can also be put in place outside the power sector: in particular, the results of the study reported in [2] and in chapter 3 showed the importance of the availability of a significant amount of gas storage, both for modulation and, especially, for strategic purposes, that is the best insurance for all gas consumers. The development of an adequate amount of gas storage infrastructures both at the European level and, especially, in the countries where natural gas has a large share of primary energy consumption, should have a high priority in the overall energy policy.
Another important remedy to a fuel supply shortage is the diversification of both suppliers and of supply infrastructures: the former reduces the counterpart risk, while the latter reduces the risks related to accidents and, for example, in case of new pipelines with different paths, can reduce the risk of shortages caused by transit countries. As for natural gas, LNG terminals are the most flexible way to implement diversification, since their supply is tied neither to a single supplier nor to a single pipeline.
In this respect, the main policy recommendation is therefore to prioritize new energy supply infrastructures at the European level according to their diversification capability.

As far as the <u>transmission</u> part of the electricity supply chain is concerned, in [3] and in chapter 4 we assessed the impact of a non-optimal development of the European cross-border transmission capacity.
Needless to say, the main remedy to a non optimal development of the European cross-border electricity transmission network is to invest in new interconnections, so that the

reduction of bottlenecks makes easier to transport cheaper energy where it is needed, increasing security of supply, but also allowing for a greater integration and for a more efficient operation (with reduction of local market power) of the Internal Electricity Market and, in the end, for a more optimized operation of the generation set, with significant economic benefits.
This remedy is of course not so easy to implement, neither by TSOs, nor by private investors interested in merchant lines projects. In fact, such investments are typically affected by several uncertainties[34], mainly due to:

- complex legal and regulatory contexts, especially for permitting procedures, stemming from a multitude of different authorities, with different administrative levels (European, national, local) that may differ from one country to another and that may have different priorities;
- the lack of social acceptance that severely delays or jeopardizes the realization of such projects;
- due to the long-term time horizon that characterizes network projects, the inherent uncertainty in predicting the future location, amount and type of generation and load.

To reduce such uncertainties[35]:

- the establishment of the *Agency for the Cooperation of Energy Regulators – ACER* foreseen by the 3rd Energy Package should be a significant step towards a more harmonized regulatory framework at the European level;
- as for <u>permitting procedures</u>, it is necessary[36]:
    - to act on the legal framework:
        - ⇨ simplify and rationalize the procedures (reduce the number of entities involved, the number of phases, etc.):
            - in case of strategic infrastructure projects, the procedures should be centralized at one (national) level;
            - upgrading of existing lines should require simplified procedures with a shorter duration;
        - ⇨ set reasonable maximum time limits for the completion of procedures;
        - ⇨ harmonize the procedures and criteria for authorization at the EU level, through binding guidelines;
        - ⇨ get an early binding pre-approval of the projects as reported in TSOs' development plans, to avoid TSOs spending time to justify the need for the projects during permitting procedures;
    - to designate an "arbiter" / "facilitator" (e.g. ACER) promoting compromises, dealing with controversies and speeding up the realization of strategic projects in trans-national cases;

34 As a general remark, one of the main barriers to long term investments in the energy sector (that usually are quite capital intensive) is regulatory and legal uncertainty: it is fundamental to guarantee investors with some basic key conditions under which they will have to operate, in order to let them correctly assess their risks.
35 Some of the following policy recommendations are being further discussed within the EC REALISEGRID project, coordinated by RSE.
36 Additional detailed recommendations that can be shared are reported in the recent *"ENTSO-E position paper on permitting procedures for electricity transmission infrastructures"* of 29 June 2010.

- as for the lack of social acceptance, it is necessary:
  - to provide a clear and objective vision of benefits and costs bound with the new infrastructures (also in order to prioritize investments to select which ones are worth to be funded by EU);
  - to clearly state the cost for the society deriving from inaction or from sub-optimal actions;
  - to clarify the relationship between RES integration, security of supply and grid development;
  - to clarify the relationship between costs and different technical solutions (e.g. overhead lines vs. underground cables);
  - to promote a cultural action dealing with all the key issues related to the public perception of a new transmission line (negative impacts on human health, landscape, property value, noise, migratory paths, etc.; feelings like *"burden to me, benefits to others"*, *"home invasion"*, *"lack of democracy"*, lack of *"serious"* information, etc.), opening a discussion on a clear and sound scientific basis with the help of independent and competent bodies, in order to allow for an informed comparison between the "cons" and the "pros" of the projects;
  - to promote a thorough evaluation of property value, so as to bring about a fair compensation (including "immaterial" aspects) that can be agreed by all the parties;
  - generally speaking, the economic side of the problem is very important to gain consensus among the involved populations: they must know that the realization of the projects will reduce their electricity bills (either by imports of cheaper energy or by direct compensations), otherwise the *nimby* attitude would be their first and easiest choice; we will be back on this point later on discussing "locational signals";

- as for the uncertainties concerning the future developments of generation and demand:
  - they can be effectively tackled by carrying out adequate scenario analyses, just like it has been done in the study reported in [3] and in chapter 4, based on POLES scenarios; this approach is supported also by ENTSO-E that states that *"scenario analyses at national, regional and pan-European levels are key elements in order to decide on grid extensions and to adequately assist political reasoning"* taking into account *"fuel prices, economic and monetary conditions, geopolitical developments, meteorological conditions, technological breakthroughs, market mechanisms, regulatory and legal frameworks"*;
  - moreover, generation companies should be discouraged (with economic penalties) from initiating permitting procedures if they are not strongly committed to realize the investments;

- finally, the use of appropriate technology solutions (e.g. FACTS) can increase transmission capacity of the existing infrastructure, thus avoiding the need for investments in new lines; these faster and less expensive solutions must be adequately incentivized and remunerated by regulation.

Up to this point we have discussed the problems related to *each generic* development of the European cross-border transmission network (and most of the above mentioned issues are relevant for expansions of national transmission networks, too), but it is very

important to end up with an *optimal set* of developments, according to the considered reference scenarios.
Again, this is exactly what has been done in the study reported in [3] and in chapter 4, following an approach supported also by ENTSO-E, that in its recent *"Research and Development Plan"* endorses the development of *"Advanced tools for analyzing the pan-European network expansion options according to energy scenarios for Europe (i.e. expansion optima that must be searched to maximize European welfare)"*, specifying that optima are to be searched at the EU level and no longer only at the national level.
As it is desirable to harmonise generation and transmission development, it is important that regulation foresees the provision of "locational signals", i.e. the spatial (zonal/nodal) differentiation of electricity prices (due to maximum transfer capability constraints and losses on the lines) and of transmission charges (calculated on the basis of how much each agent uses the network).
Locational signals can therefore provide adequate economic incentives to market players about the dependency of the energy supply costs on the physical location of production/consumption facilities, thereby leading to a more efficient system operation in the short term and promoting a more optimized siting of new generators and loads in the longer term. Moreover, as above mentioned, consumers that are exposed to locational electricity prices may directly benefit e.g. from price reductions due to the installation of a new power plant nearby or of a new transmission line[37], so that they get correct incentives not to assume an a priori *nimby* attitude.

As far as distribution network is concerned, the main challenge is its progressive transformation from a "passive" to an "active" network, due to the increased penetration of distributed generation. In this respect, Directive 2009/72/EC states that *"Member States should encourage the modernisation of distribution networks, such as through the introduction of smart grids, which should be built in a way that encourages decentralised generation and energy efficiency"*.
Generally speaking, current distribution networks have some margins to host a limited amount of distributed generation but, over a certain level, the quality and reliability of service can no longer be guaranteed, so that additional measures, ranging from simple changes in protection or control settings to massive network investments, are needed.
Therefore, the development and deployment of new communication and control technologies is the key to make distribution grids "smarter", i.e. able to *"cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety"*, as stated in the ERGEG's *"Position paper on smart grids"*.
From the technological point of view, cooperation among international, European and national standardization bodies, regulatory authorities, grid operators and manufacturers should be encouraged to further improve open communication protocols and standards for information management and data exchange, in order to achieve interoperability of smart grid devices and systems so as to avoid any technical barrier to their deployment.
Another key point is, from a regulatory point of view, how to support distribution network companies in their investments in such innovative technologies, to ensure that their deployment provides a cost-effective solution to the needs of network users.

[37] Nevertheless, it must be taken into account that increasing transmission capacity along a congested path reduces prices in the importing area, but increases them in the exporting area.

To this aim, we share ERGEG's view that regulators must not attempt to choose or impose specific solutions – they must remain technologically neutral – leaving network companies to manage their business which they have ultimate control over in the most appropriate way: regulation should focus on the benefits for network users and not on the technical details to get them.

Therefore, regulatory schemes for promoting improvements in performance of electricity distribution networks require the quantification, through appropriate indicators, of the effects and benefits of such investments in "smartness".

The definition of performance targets and indicators should be accompanied by clear, transparent and objective measurement rules that allow to observe, quantify and verify such targets. Moreover, performance targets should be benchmarked to define their expected values and should be strictly related to the pursued objectives: they should therefore be cleansed of external effects outside the control of network operators. Then, having defined targets and indicators, it is possible to use either incentive regulation, where regulated entities are either rewarded if they overperform or penalized if they underperform with respect to such targets, or minimum requirements regulation, where a minimum performance level must be accomplished by the regulated entity, or a combination of both. In the above mentioned ERGEG's position paper a set of indicators is proposed.

The last (but not least) ring of the chain is demand, for which the two main issues related to security of supply are "demand response" and "energy efficiency".

Demand response is related to the capability of consumers to respond to price signals or to signals concerning the criticality of system operation with a variation of their consumption profiles.

Demand response's main beneficial effect is to reduce demand in peak load / high price periods, possibly moving part of it to less critical / lower price hours. A lower peak load:

- increases reserve margin (thus increasing security of supply) and, in the longer term, reduces the need for investments in new generation capacity;
- reduces the stress (and possible congestion) on both transmission and distribution networks, delaying the need for network expansions;
- reduces the necessity of dispatching costly and low efficiency power plants during peak hours, thus reducing also fuel consumption and CO_2 emissions;
- by making demand more elastic to price, reduces the possibility of exercising market power by producers and also reduces price volatility.

In fact, electricity demand has always been quite inelastic and an increase of its flexibility requires:

- a way to communicate the price/criticality signals to consumers;
- a strength of such signals (or of the rewards for the response) significant enough to convince consumers to respond;
- the real possibility of consumers to respond to the signals, according to their way of life and to the electric devices they can manage manually and/or automatically.

The aforementioned communication requirements and the necessity to measure and record the amount and the time of the response entail the availability of "smart meters", which is endorsed also by Directive 2009/72/EC, that, given a positive economic assessment of their long-term costs and benefits, states that at least 80% of consumers shall be equipped with intelligent metering systems by 2020. The timing of such requirement does not seem very much ambitious, taking into account best practices in countries like Italy.

As for the strength of the signals, we stress again that it is very important for the success of demand response programs: simple peak / off-peak tariffs with limited price differences that allow consumers to spare some tenths of euros per year with their response will not have any significant success. Moreover, the signals must be simple and easily understandable by consumers, so that they can correctly respond to them.

Finally, provided that the proper communication and metering devices are in place and that there is a substantial economic convenience in participating to demand response programs, information campaigns are necessary to enroll as many consumers as possible.

As far as “energy efficiency” is concerned, in the EU energy policy its implementation is foreseen as an important means to reach the mandatory targets concerning CO_2 emissions reduction and RES development (whose objective is proportional to gross final consumption).

To this aim, several European directives (such as Directive 2006/32/EC of 5 April 2006 on energy end-use efficiency and energy services, Directive 2009/125/EC of 21 October 2009 establishing a framework for the setting of ecodesign requirements for energy-related products, Directive 2010/30/EU of 19 May 2010 on the indication by labelling and standard product information of the consumption of energy and other resources by energy-related products, Directive 2010/31/EU of 19 May 2010 on the energy performance of buildings, etc.) and national laws and regulations (such as the National Energy Efficiency Action Plans) have been issued and are being implemented.

Generally speaking, it is clear that a lower energy consumption reduces the stress on the whole supply chain, thereby increasing security of supply.

Moreover, most of the actions that can be carried out to increase energy efficiency have a “negative” cost, i.e. they repay by themselves, therefore they are more economically efficient than actions to support RES development and to reduce CO_2 emissions (such as Carbon Capture and Storage technologies).

Nevertheless, some promotion is necessary, typically with fiscal incentives together with obligation schemes, such as White Certificates, and minimum standard requirements, in order to overcome possible barriers, such as the financial capability of customers to invest in more efficient appliances, the impact on their way of life of the implementation of such actions, the short-term view of some industrial management, that would avoid to reduce the profits of the current financial year (by investing in more efficient technologies), in exchange for future lower production costs, etc.

8 References

[1] SECURE Deliverable 5.6.3: *"Costs of electricity interruptions*", April 2009.

[2] SECURE Deliverable 5.6.2: *"Assessment of the impact of gas shortages risks on the power sector"*, December 2009.

[3] SECURE Deliverable 5.6.1: "*Optimisation of transmission infrastructure investments in the EU power sector"*, rev. 1, July 2010.

[4] SECURE Deliverable 5.6.4: *"Role and responsibilities of TSOs for security of supply"*, February 2011.

[5] SECURE Deliverable 5.6.5: "*Electricity security of supply with increased presence of distributed generation"*, September 2010.