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 5.6.2

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

Due date of deliverable: end of November 2009
Actual submission date: 24 December 2009

Start date of project: 1/1/2008 Duration: 39 months

Organisation name of lead contractor for this deliverable: ERSE (ENEA Ricerca sul Sistema Elettrico)

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)	

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

ERSE (ENEA Ricerca sul Sistema Elettrico) with contributions of OME and Ramboll

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1 Introduction

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 report 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. 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.

2 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[1].

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.

[1] See: http://www.eni.it/it_IT/attachments/documentazione/bilanci-rapporti/rapporti-2009/Relazione-finanziaria-semestrale-consolidata-30-giugno-2009.pdf.

3 STEP 2: impact assessment

In the following, the impact assessment of the gas supply shortages in Italy and in Hungary is reported.

3.1 Gas shortage in Italy

In the following, the monthly balance between gas supply and demand in Italy in the reference year 2015 is reported, in order to calculate the amount of gas available for power generation in case the gas supply shortage occurs.
As mentioned in chapter 2, we assume 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 from November to March, i.e. the most critical ones in terms of gas consumption in Italy, due to heating demand.

3.1.1 Supply

3.1.1.1 National gas production

The Italian national gas production is rapidly declining and, according to ENI and to the Ministry of Economic Development, the trend is not foreseen to change. In Table 1 productions of years from 2001 to 2007 are reported[2].

2001	2002	2003	2004	2005	2006	2007
15.154	14.294	13.550	12.579	11.467	10.420	9.124

Table 1: Italian national gas production (bcm).

Data reported in Table 1 show a linearly decreasing trend that, if extrapolated, leads to a value of **1.34 bcm** in 2015 (see Figure 1), that is **0.11 bcm/month**.

[2] Source: Authority for Electric Energy and Gas (AEEG) http://www.autorita.energia.it/it/dati/gm52.htm.

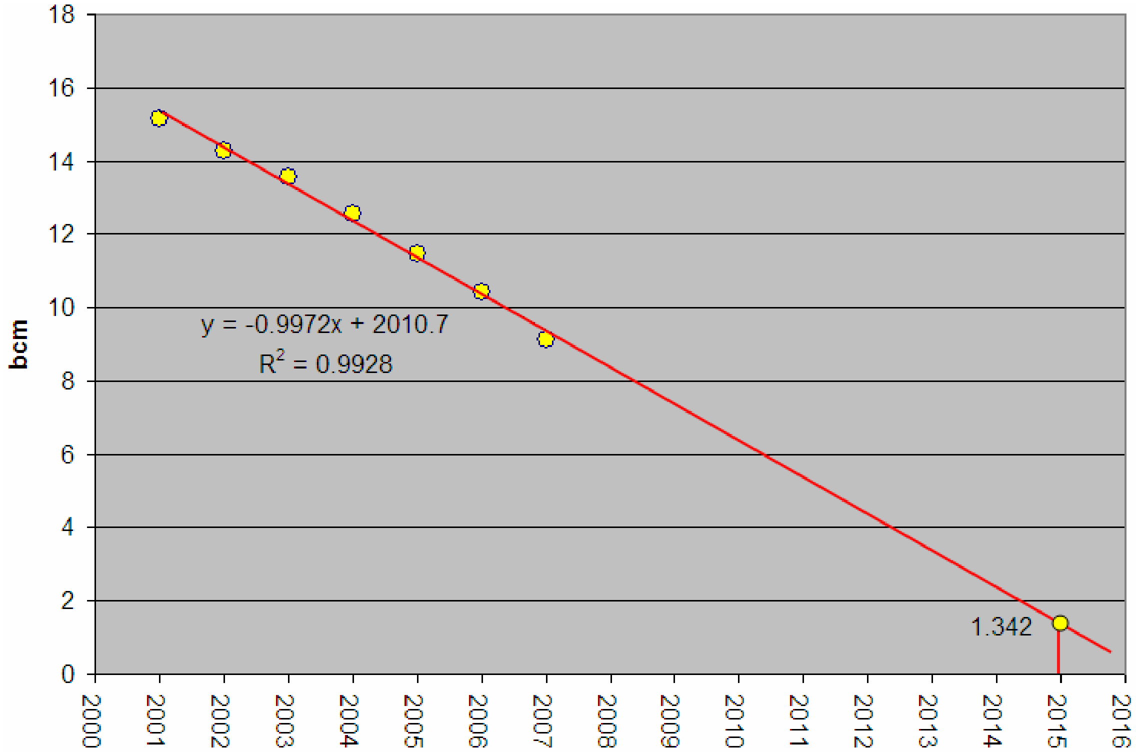

Figure 1: Extrapolation to 2015 of the Italian national gas production.

3.1.1.2 Import pipelines

The annual maximum capacity of the different import pipelines is reported in the following Table 2.
Together with all of the existing pipelines, we take into account also the new *IGI Poseidon* pipeline, connecting Greece to Italy (entry point at Otranto), completing the natural gas corridor through Turkey, Greece and Italy (*Interconnection Turkey Greece Italy*: *ITGI*) and allowing Italy and the rest of Europe to import natural gas from the Caspian Sea and the Middle East. IGI is expected to start operation from late 2012[3].
Considering out of order the *TransMed* pipeline, the maximum effective monthly import capacity is therefore around **6.34 bcm/month**.
In fact, there are other projects for new import pipelines[4] in Italy, but none of them can be assumed for sure to be in operation by 2015.
An exception could be the *GALSI*, from Algeria to Sardinia-Tuscany (8 bcm/year) that, after some delays, is currently expected to be in operation in 2014. Nevertheless, since its Environmental Impact Assessment has not been approved yet (it is expected by the first quarter 2010) and since the final investment decision has not been taken yet (it is expected by mid 2010), we will not take it into account in the present study.

[3] Source: http://www.igi-poseidon.com/english/project.asp.
[4] See: Authority for Electric Energy and Gas (AEEG) http://www.autorita.energia.it/it/dati/infragas1.htm.

Entry point	Maximum theoretical annual capacity	Maximum effective annual capacity[5]	Maximum effective monthly capacity[6]
Tarvisio (TAG)	40.2[7]	36.7	3.06
Passo Gries (TENP / TRANSITGAS)	23.4	21.3	1.78
Gela (GREENSTREAM)	11[8]	10.0	0.84
Gorizia	0.73	0.67	0.06
Otranto (IGI Poseidon / ITGI)	8	7.3	0.61
SUBTOTAL	83.3	76.1	6.34
Mazara del Vallo (Transmed TTPC / TMPC)	33.5	30.6	2.55
TOTAL	116.8	106.7	8.89

Table 2: Import capacity from pipelines assumed for year 2015 (bcm).

3.1.1.3 LNG terminals

In Italy there are currently two LNG terminals: Panigaglia (ENI) and Porto Levante (Adriatic LNG), this latter inaugurated on October 20, 2009.
Several projects for new LNG terminals have been proposed[9], but only Livorno (OLT Offshore LNG, 3.75 bcm/year) is at an advanced stage and it is foreseen to be in operation in 2011. Therefore, all of the other projects will not be taken into account in this study.
In the following Table 3 import capacities from the LNG terminals considered in this study are reported. The maximum effective monthly import capacity is around **1.21 bcm/month**.

[5] Calculated assuming 8000 hours/year at maximum theoretical capacity, taking into account maintenance outages.
[6] Corresponding to the maximum effective annual capacity divided by 12.
[7] From end 2009, source ENI.
[8] From 2011, source ENI.
[9] See: Authority for Electric Energy and Gas (AEEG) http://www.autorita.energia.it/it/dati/infragas3.htm.

Terminal	Maximum theoretical annual capacity	Maximum effective annual capacity[10]	Maximum effective monthly capacity[11]
Panigaglia (ENI)	3.5	3.3	0.28
Porto Levante (Adriatic LNG)	8	7.6	0.63
Livorno (OLT Offshore LNG)	3.75	3.6	0.30
TOTAL	15.25	14.5	1.21

Table 3: Import capacity from LNG terminals assumed for year 2015 (bcm).

3.1.1.4 Gas storage

In Italy gas storage capacity for the modulation service is currently about 8.72 bcm. There are several projects[12] for new storage facilities but, since none of them is in the construction phase, we will not take them into account for this study.
We assume that storage is full at the end of October (end of the injection phase) and that all the aforementioned capacity available for modulation is used till the end of March (end of the withdrawal phase).
Moreover, we assume that withdrawal is carried out according to the optimal profiles defined by STOGIT[13] and EDISON[14], the two companies operating the storage facilities. Such optimal profiles are reported in Table 4.

Company	November	December	January	February	March
STOGIT	0.92	1.93	2.85	2.26	0.42
EDISON	0.03	0.08	0.09	0.08	0.05
TOTAL	0.95	2.01	2.94	2.34	0.47

Table 4: Optimal monthly withdrawal profile from the storage for the modulation service (bcm).

[10] Calculated assuming 95% of the maximum theoretical capacity, taking into account logistic constraints.
[11] Corresponding to the maximum effective annual capacity divided by 12.
[12] See Authority for Electric Energy and Gas (AEEG) http://www.autorita.energia.it/it/dati/infragas2.htm.
[13] See: http://www.stogit.it/wps/wcm/connect/b54132804ce494a9b524b5e7fdf8fd8f/2009+02+02_Servizio+di+MODULAZIONE+-+Fase+di+Erogazione+-+Profili+di+utilizzo+e+fattori+di+adeguamento+per+la+capacit%C3%A0+di+erogazione+e+di+iniezione.pdf?MOD=AJPERES.
[14] See: http://www.edisonstoccaggio.it/pages/page.aspx?item_id=162.

It must be taken into account that in Italy there is an additional strategic gas storage capacity of about 5.17 bcm: in this study we will firstly assess to what extent fuel switching in power generation (together with possible increase of electricity imports) can compensate for the assumed gas import shortage, without resorting to strategic storage (similarly to what happened in the cold 2005/2006 winter, when fuel oil fired power plants were constrained on to avoid depletion of strategic gas storage), to be reserved primarily for satisfying heating demand. Then, additional considerations will be made about the use of strategic storage in case it is necessary to avoid unserved energy in the power system.

3.1.2 Demand

3.1.2.1 Consumption of the industrial sector

We assume that in 2015 gas consumption of the industrial sector will recover to the pre-economic crisis levels, corresponding to about **1.7 bcm/month**[15].
Assuming this value, we implicitly give priority to industry gas consumption over power generation, even if, at least to a small extent, the industrial sector can perform some fuel switching in case of gas shortage.

3.1.2.2 Consumption on gas distribution networks

Consumption on gas distribution networks is mainly due to heating demand. In this study we will determine the heating demand in a cold winter whose probability to occur is once every 20 years, that is the reference winter defined by the Italian law regulating the gas sector (Legislative Decree nr. 164 of May 23, 2000).
To this aim we used the time series of the *degree days*[16] measured in 18 Italian cities from 1962 to 2009 and the daily gas consumption measurements in the interconnection points between the transport and the distribution networks. Starting from such values, we carried out the following computations:

1) we calculated a single time series (that we could call *Italy degree days*) as the average of the 18 cities' degree days, weighted on the consumptions on gas distribution networks of the areas corresponding to each city in the 2008 / 2009 winter;
2) from the *Italy degree days* time series, we calculated the monthly sum values whose probability to occur is once every 20 years;
3) we used the gas consumption on distribution networks of June 2009 as the *basis*, i.e. the level of gas consumption independent from temperature;
4) we calculated the gas consumption due to heating demand in the months between October 2008 and April 2009 by subtracting the *basis* (point 3) to the overall consumption;

[15] Source: Ministry of Economic Development.
[16] *Degree day = max (0 ; 18 – (Tmin + Tmax) / 2)*, where *Tmin* and *Tmax* are the minimum and maximum daily temperatures.

5) we calculated the 2008 / 2009 *gradient*, as the ratio between gas consumption due to heating demand (point 4) and the corresponding 2008 / 2009 sum of the *Italy degree days*;
6) finally, we calculated the monthly gas consumption whose probability to occur is once every 20 years as the sum of the *basis* (point 3) and the product of the *gradient* (point 5) and the monthly sums of the *Italy degree days* whose probability to occur is once every 20 years (point 2).

The result is reported in Table 5.

November	December	January	February	March
4.57	6.30	6.68	5.47	4.49

Table 5: Monthly gas consumption on distribution networks whose probability to occur is once in 20 years (bcm).

3.1.2.3 Network consumptions and losses

On average, network consumptions and losses are **0.125 bcm/month**.

3.1.3 Gas available for power generation

The balance of supply and demand calculated in paragraphs 3.1.1 and 3.1.2 provides the monthly amount of natural gas available for power generation. The results are reported in Table 6.

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

3.2 Gas shortage in Hungary

Hungary is principally supplied with gas through the Beregovo pipeline from the Ukraine, which has a capacity of 11 bcm/year: as above mentioned, we will assume an interruption of supply from this pipeline for the 5 cold months from November to March, just like the Italian shortage scenario.

3.2.1 Supply

In addition to the aforementioned Beregovo pipeline, in Hungary there is also an import pipeline from Austria, Mosonmaggarovar, whose capacity is about 2.6 bcm/year.
Hungary also maintains at present four gas storage facilities accounting for some 3.5 bcm of working gas capacity with a daily maximum withdrawal rate of 50.5 Mcm/day.
Hungary 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.[17] Just like in the Italian shortage case, in this study we will firstly assess to what extent fuel switching in power generation (together with possible increase of electricity imports) can compensate for the assumed gas import shortage, without resorting to strategic storage. Then, additional considerations will be made about the use of strategic storage in case it is necessary to avoid unserved energy in the power system.
Hungary maintains also an annual domestic production of approximately 2.5 bcm, though domestic reserves of gas have been declining somewhat in recent years, so such supply cannot be guaranteed in the long term.
The following Table 7 identifies the monthly available supply of gas to Hungary; the monthly supply is also adjusted for the January average using the available data in the Eurostat database; finally the supply available in the shortage scenario of a total disruption in gas supply from the Ukraine is evaluated.
The capacity and supply data are taken from the GIE capacity database and the GSE storage databases with an assumption of a load factor of 90% made for the pipelines.
Therefore, in the case of a total disruption of supply from the Ukraine for a cold month, the supply available for Hungary can be estimated around **1.36 bcm/month**.

[17] GIE Storage Map, http://www.gie.eu.com/maps_data/storage.html.

Supply Source	Daily maximum supply [Mcm/day]	January available supply [bcm/month]	Shortage scenario [bcm/month]
Ukraine pipeline	**30.12**	**0.81**	**-**
Austria pipeline	**7**	**0.19**	**0.19**
Existing storage	**50.5**	**0.70**[18]	**0.70**[18]
New storage	**25**[19]	**0.14**[20]	**0.14**[20]
Domestic production	**11**	**0.33**	**0.33**
TOTAL supply	**123.62**	**2.17**	**1.36**

Table 7: Monthly supply of natural gas in Hungary without and with the shortage.

3.2.2 Demand

Table 8 below identifies the average January demand scenario and the corresponding emergency (shortage) scenario. Under the emergency situation we have taken into account that 10% of industrial consumers in Hungary have interruptible contracts.
Moreover, Hungary exports a small amount of gas to Serbia via pipeline amounting to 0.048 bcm/year.
The demand data have been taken from Eurostat and then averaged from January 2006 to 2009 to get demand adjusted for seasonality.
This implies that the calculations have been made for an average winter and not for an extreme one, such as the 1 in 20 years winter taken into account in the Italian shortage scenario, whose estimation requires a long time series of temperature measurements (see paragraph 3.1.2.2). To compensate for this, we will assume that all the 5 months taken into account have the same emergency situation demand as the one reported in Table 8.

[18] The value is simply calculated as the overall 3.5 bcm storage capacity divided by the 5 months from November to March. As an example, the maximum withdrawal in 2009 in response to the January Ukraine gas crisis was 0.92 bcm/month.
[19] Purported withdrawal rate according to the EBRD database.
[20] The value is simply calculated as the overall 0.7 bcm new modulation storage capacity divided by the 5 months from November to March.

Sector	January average demand [bcm/month]	Emergency situation [bcm/month]
Households	0.900	0.900
Industry	0.130	0.117
Exports	0.004	0.004
Other	0.260	0.260
TOTAL	1.294	1.281

Table 8: January gas demand (except power generation) in Hungary in an average and in emergency (shortage) situation.

3.2.3 Gas available for power generation

With a 1.36 bcm/month supply and a 1.28 bcm/month demand (except power generation), gas available for power generation in the considered shortage scenario is very little, i.e. about **0.079 bcm/month**.

4 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 9 data provided by Eurostat (see [1]) 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 9: 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 Neteherlands 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 (see also paragraph 5.2.2.2.2).

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 neighbouring countries, according to the NTC (Net Transfer Capacity) values.

In the following Table 10 the results of the analysis (carried out using data concerning year 2008 taken from [2][3][4][5][6][7]), 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 described in paragraph 5.2 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 10: 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).

5 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.
The model and the results of its runs will be described in the following.

5.1 The MTSIM power system simulator

MTSIM (*Medium Term SIMulator*), developed by ERSE, is a zonal electricity market simulator able to calculate the hourly clearing of the market over an annual time horizon, calculating the zonal prices and taking primarily into account:

- variable fuel costs of thermal power plants;
- other variable costs that affect power plants (such as O&M, CO_2 emissions, etc.);
- bidding strategies put in practice by producers, in terms of mark-ups over production costs.

The main results provided by the simulator are:

- 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:

- power transfer capacity on the interconnections between market zones; the equivalent transmission network is modeled using the so-called *Power Transfer Distribution Factors* (PTDF[21]) and MTSIM can model active power flows by calculating a DC Optimal Power Flow; in this way, transmission bottlenecks can be identified and the needs for network reinforcement can be quantified;
- power plants unforced and scheduled unavailability, as well as start-up and shut-down flexibility;
- constraints on plant operation (e.g. "must-run") and on fuel consumption over a certain time period (this feature has been used to model the gas shortages);

[21] Power Transfer Distribution Factors, commonly referred to as PTDFs, express the percentage of a power transfer from source A to sink B that flows on each transmission facility that is part of the interconnection between A and B.

- emission constraints and related trading of emission allowances at an exogenous price set in the relevant international markets (e.g. ETS, CDM, JI).

Non-dispatchable power plants operation (typically RES sources such as wind, photovoltaic, run-of-river hydro, etc.) is not modelled endogenously: hourly generation profiles have to be provided as input to the simulator.

In the present study, MTSIM has been used to simulate the optimal behavior of the modeled European power system (see paragraph 5.2), 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.

5.2 The model of the European power system

5.2.1 Representation of the transmission network

The European AC transmission network has been modeled with an equivalent representation (see Figure 2) 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).
The abbreviations used in Figure 2 are the following:

- AT: Austria
- BG: Bulgaria
- BL: Belgium and Luxembourg
- BX: Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia, Serbia)
- CH: Switzerland
- CZ: Czech Republic
- DE: Germany and Denmark West
- ES: Spain
- FR: France
- GR: Greece
- HR: Croatia
- HU: Hungary
- IT: Italy
- NL: The Netherlands
- PL: Poland
- PT: Portugal
- RO: Romania
- SI: Slovenia
- SK: Slovak Republic
- UA_W: Ukraine West

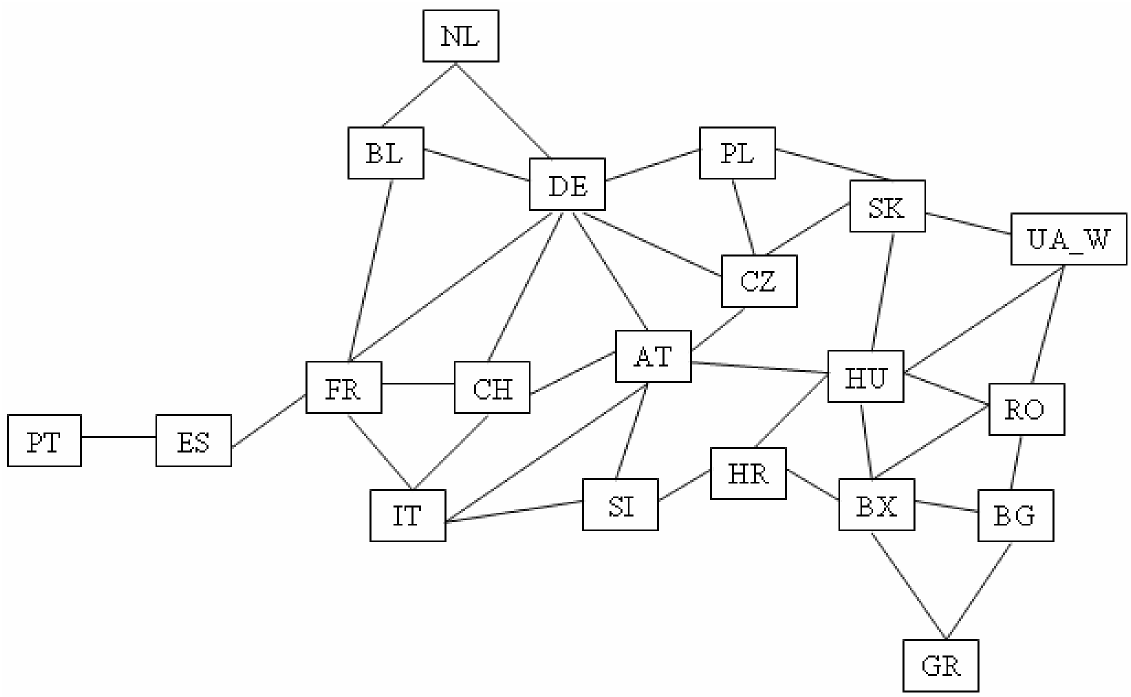

Figure 2: Equivalent representation of the European AC transmission network.

The PTDF[22] (*Power Transfer Distribution Factor*) matrix used in the MTSIM simulator has been calculated on the basis of a series of DC Load Flows executed on a detailed representation (about 4000 nodes) of the European AC network.
In each of these load flows, with the slack node put in France, 100 MW of active power has been injected, in turn, into each country, while the load of all the other N-1 countries has been increased by 100/(N-1) MW.
For the sake of simplicity, the presence of phase shifter transformers has been neglected. The equivalent value of the reactance (x_{ij}) of each European cross-border interconnection has been provided by ENTSO-E [2].
As far as the NTC values (for both flow directions) are concerned, the latest ENTSO-E available data (Summer 2009 and Winter 2008-2009: see [2]) have been used. Moreover, for each cross-border interconnection and for each month, the average hourly exchanged power (equal to the ratio between the monthly exchanged power and the number of hours in that month) has been calculated, using data from the ENTSO-E Statistical Database. In case the average hourly exchanged power in a certain month was higher than the corresponding NTC value, the former has been taken into account as the reference interconnection transmission capacity[23].
In addition, for all the interconnections for which expansions of the transmission capacity are expected before 2015 (the reference year for the simulations), the new increased NTC values have been taken into account.

[22] Power Transfer Distribution Factors, commonly referred to as PTDFs, express the percentage of a power transfer from source A to sink B that flows on each transmission facility that is part of the interconnection between A and B.
[23] This is the case, for example, of the interconnection Slovenia ⇨ Italy.

In the following Table 11, summer[24] and winter[25] NTC values for the considered cross-border interconnections adopted for the 2015 scenario are reported.

Interconnection (A→B)	NTC values (A→B) [MW]		NTC Values (B→A) [MW]	
	Summer	Winter	Summer	Winter
PT→ES	1200	1200	1100 ÷ 1199	1300 ÷ 1433
ES→FR	500	500	1200	1400
FR→IT	3000	3250	870	995
IT→CH	1290	1810	3460	4390
FR→CH	3000	3200	1400	2300
FR→DE	2400	2900	2700	2750
FR→BL	2700	3200	1100	2200
CH→DE	4400	3200	2060	1706 ÷ 2574
DE→BL	980	980	980	0
BL→NL	2300	2400	2200	2400
NL→DE	3900	3000	4000	3850
DE→PL	800	1200	1200	1100
DE→CZ	800	800	2100	2250
DE→AT	1600	2000 ÷ 2431	1600	1800
CH→AT	1000	1200	800 ÷ 843	726 ÷ 1135
IT→AT	70	85	200	220
IT→SI	120	160	330 ÷ 660	433 ÷ 1000
PL→CZ	1800	1750	800	800
PL→SK	400	500 ÷ 618	500	500
CZ→SK	1200	1200 ÷ 1211	1000	1000
CZ→AT	800	700 ÷ 917	600	600
SK→HU	700 ÷ 895	1200 ÷ 1263	600	400
AT→HU	600	500	500	350
AT→SI	350	650	650	650
HU→BX	800	600	800	600
HU→RO	800	600	800	800
BX→BG	50	500	950	450 ÷ 648
BX→RO	300	500	500	450 ÷ 456
RO→BG	400	750 ÷ 782	500	750
BG→GR	600 ÷ 653	500 ÷ 575	100	300
BX→GR	600	100 ÷ 254	400	600
HR→BX	1000	1060	900	1020
HR→SI	700	900 ÷ 903	800	900
HR→HU	600	400	1000	1000
RO→UA_W	200	400	400	400
HU→UA_W	500	300	650	800
SK→UA_W	400	400	400	400

Table 11: Summer and winter NTC values (MW) for the considered cross-border interconnections in the 2015 scenario.

In Figure 3, cross-border DC interconnections (in red) and AC interconnections with other power systems (in blue) are shown; the additional abbreviations used are the following:

- NO: Norway

[24] Summer: May, June, July, August, September.
[25] Winter: January, February, March, April, October, November, December.

- DK_E: Denmark East
- SE: Sweden
- MA: Morocco
- GB: Great Britain
- TR: Turkey
- MD: Moldova
- BY: Belarus
- UA: Rest of Ukraine

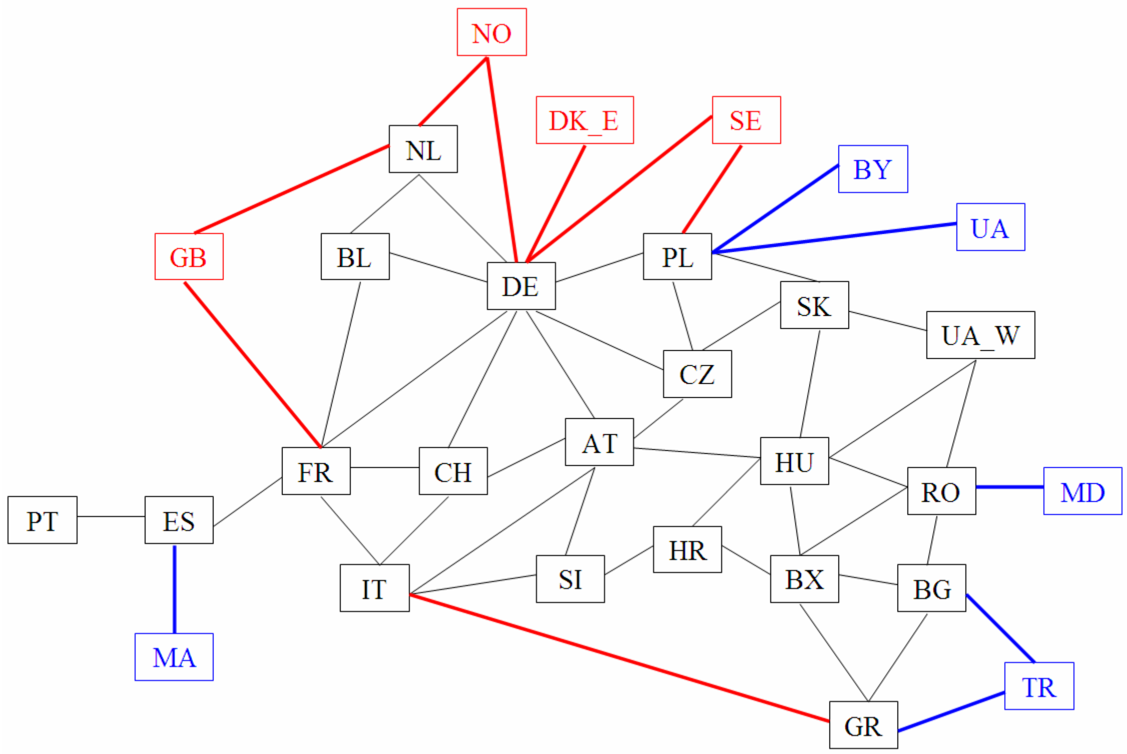

Figure 3: Cross-border DC interconnections (in red) and AC interconnections with other power systems (in blue).

As far as the electricity exchanges via DC interconnections are concerned, considering their independence from the PTDF matrix coefficients, it was decided to impose an hourly profile. The same has been done for AC interconnections with other 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 [2]) have been profiled according to the load profile of the importing country.
As for the interconnections with Turkey, currently there is no power exchange and this has been assumed in the study, even if in the next few years the Turkish power system is expected to synchronize with UCTE and the interconnections are expected to be reinforced.
Finally, regarding the new DC interconnection *"BritNed"* between Great Britain and the Netherlands (that we assume will be in operation in 2015), the same profile of the

DC interconnection between Great Britain and France has been used and scaled on the new cable's NTC (±1320 MW).
In the following Table 12 the annual electricity exchanges (for both directions) imposed on the considered interconnections are reported.

Interconnection (A→B)	From A to B [GWh]	From B to A [GWh]
NO→NL	987.1	3164.5
DK_E→DE	1424.4	1746.9
SE→DE	3250.3	2134
NO→DE	1202.1	4205.0
SE→PL	286.4	1489.7
MA→ES	0.0	3064.8
GB→FR	1910.1	8751.1
TR→BG	0.0	0.0
GR→IT	183.5	1770.1
MD→RO	773.0	0.0
UA→PL	766.0	0.0
BY→PL	554.0	0.0
TR→GR	0.0	0.0
GB→NL	1254.8	5774.8

Table 12: Annual electricity exchanges (GWh) imposed on the considered DC interconnections and on AC interconnections with other power systems in the 2015 scenario.

5.2.2 Representation of the power generation system

As shown in Figure 2, 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, as detailed in the following.
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* (available from [2]). 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 (see [8]) and of the FP7 project REALISEGRID (see [9]), as well as estimated by ERSE.

5.2.2.1 Fossil fuelled thermal power plants

5.2.2.1.1 Generation technologies

Fossil fuelled generation technologies have been firstly subdivided into non-CHP and CHP (*Combined Heat and Power*) ones, since their operating patterns and performances are quite different. Then, the different technologies and the corresponding different fuels have been taken into account.
In particular, non-CHP plants have been subdivided into:

- steam turbine power plants: fuel oil-fired, natural gas-fired, hard coal-fired, lignite-fired,
- gas turbine power plants: open cycle and combined cycle, all natural gas-fired,
- nuclear power plants.

Moreover, CHP plants[26] have been subdivided into:

- steam turbine power plants: fuel oil-fired, natural gas-fired, hard coal-fired, lignite-fired;
- gas turbine power plants: open cycle and combined cycle, all natural gas-fired.

As for Italy, data are reported also for plants fuelled with industrial process gases, blast furnace gases, refinery gases, tar, etc.
Finally, in terms of installed power capacity, for some countries it has been possible to make additional subdivisions between old (less efficient) and new (more efficient) generation technologies.

[26] Small sized CHP power plants technologies, such as internal combustion engines, have not been explicitly taken into account in the study.

5.2.2.1.2 Net generation capacity

- *Total generation capacity*

In the following Table 13, for each country, data concerning the total fossil fuelled generation capacity installed in the 2015 scenario are reported.

Country	Net generation capacity [MW]
AT	8526
BG	9810
BL	15614
BX	11455
CH	3300
CZ	14450
DE	109449
ES	55801
FR	88700
GR	12026
HR	2500
HU	8802
IT	66289
NL	27808
PL	28377
PT	8526
RO	11709
SI	2791
SK	5101
UA_W	2517
Total	**488502**

Table 13: Total fossil fuelled generation capacity (MW) installed in the 2015 scenario.

- *CHP generation capacity*

In the following Table 14 the net generation capacity and the estimated electricity production of the fossil fuelled CHP power plants for each country are reported (source: Eurostat 2007 data, see [1], except for the Italian data, estimated by ERSE).
Since no data are available about the split of CHP production into the different application sectors (industry, residential, tertiary, etc.), it has not been possible to differentiate it into different production profiles. Therefore, in the model a flat annual profile has been assumed.

Country	Net generation capacity [MW]	Electricity production [GWh]
AT	3080	9900
BG	1300	4050
BL	2200	11490
BX	4996	19736
CZ	4630	11430
DE	24053	86448
ES	3750	21650
FR	5340	18430
GR	220	1020
HR	783	2349
HU	2200	8570
IT	14777	89294
NL	8340	31050
PL	9020	27570
PT	1070	5820
RO	4480	6620
SI	330	1090
SK	2160	7190
Total	**92729**	**363707**

Table 14: Net generation capacity (MW) and estimated electricity production (GWh) of fossil fuelled CHP power plants.

- *Steam turbine power plants*

In the following tables, for each country, the net generation capacities of the different kinds of steam turbine power plants, both non-CHP and CHP, are reported.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
AT	398	78	476
BL	402	7	409
BX	196	4	200
DE	5268	232	5500
ES	1371	29	1400
FR	9137	263	9400
GR	718	0	718
HU	406	1	407
IT	3691	378	4069
NL	195	5	200
SK	100	6	106
Total	**21882**	**1003**	**22885**

Table 15: Net generation capacity (MW) of fuel oil-fired steam turbine power plants.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
AT	1109	288	1397
BL	2824	440	3264
BX	458	1	459
DE	2990	370	3360
HU	1885	595	2480
IT	6403	463	6866
PT	1943	147	2090
SI	556	4	560
Total	**18168**	**2308**	**20476**

Table 16: Net generation capacity (MW) of natural gas-fired steam turbine power plants.

As far as Italy is concerned, it has been possible to make an additional distinction between conventional natural gas-fired steam turbine power plants and "repowering" ones, where open cycle gas turbines are used to generate additional power and (with their exhaust gases) to pre-heat feedwater, in parallel with high-pressure pre-heaters of the conventional cycle.

Country	Net generation capacity [MW]			
	Conventional		Repowering	
	non-CHP	CHP	non-CHP	CHP
IT	1555	463	4848	0

Table 17: Net generation capacity (MW) of Italian natural gas-fired steam turbine power plants.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
AT	1383	365	1748
BG	1693	447	2140
BL	245	3	248
CZ	853	697	1550
DE	29284	10216	39500
ES	6699	25	6724
FR	4048	252	4300
GR	770	30	800
HR	492	208	700
HU	143	12	155
IT	9380	0	9380
NL	6298	1080	7378
PL	12659	6257	18916
PT	1776	0	1776
RO	970	1234	2204
SI	162	68	230
SK	121	279	400
UA_W	2317	200	2517
Total	**79293**	**21373**	**100666**

Table 18: Net generation capacity (MW) of hard coal-fired steam turbine power plants.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BG	2990	790	3780
BX	3709	4982	8691
CZ	4787	3913	8700
DE	15272	5328	20600
ES	2991	11	3002
GR	4629	179	4808
HU	987	84	1071
PL	5573	2754	8327
RO	1903	2422	4325
SI	594	251	845
SK	88	202	290
Total	**43523**	**20916**	**64439**

Table 19: Net generation capacity (MW) of lignite-fired steam turbine power plants.

- *Gas turbine power plants*

In the following tables, for each country, the net generation capacities of open cycle and combined cycle gas turbine power plants, both non-CHP and CHP, are reported.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
AT	1468	1223	2691
BG	828	62	890
BL	177	74	251
DE	11071	3538	14609
FR	2311	1889	4200
GR	1253	2	1255
HR	588	276	864
HU	584	655	1239
IT	1272	955	2227
PT	532	98	630
SI	320	5	325
SK	0	621	621
Total	**20404**	**9398**	**29802**

Table 20: Net generation capacity (MW) of open cycle gas turbine power plants.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
AT	1207	1007	2214
BL	3864	1631	5495
BX	2095	10	2105
CH	100	0	100
CZ	681	19	700
DE	10666	3414	14080
ES	33525	3685	37210
FR	3244	2656	5900
GR	4436	9	4445
HR	637	299	936
HU	740	830	1570
IT	27203	12981	40184
NL	12505	7245	19750
PL	1126	8	1134
PT	3405	625	4030
RO	3056	824	3880
SI	133	2	135
SK	0	1050	1050
Total	**108623**	**36295**	**144918**

Table 21: Net generation capacity (MW) of combined cycle gas turbine power plants.

- *Nuclear power plants*

In the following Table 22, for each country, the net generation capacities of nuclear power plants are reported.

Country	Net generation capacity [MW]
BG	3000
BL	5947
CH	3200
CZ	3500
DE	11800
ES	7465
FR	64900
HU	1880
NL	480
RO	1300
SI	696
SK	2634
Total	**106802**

Table 22: Net generation capacity (MW) of nuclear power plants.

- *Thermal power plants fuelled with industrial gases and tar*

As for Italy, in the following Table 23 data are reported concerning net generation capacity and annual electricity production of plants fuelled with industrial process gases, blast furnace gases, refinery gases, tar, etc. For these plants, a flat generation profile is assumed.

Fuel	Net generation capacity [MW]	Electricity production [GWh]
• Industrial process gases • Blast furnace gases	1962	13853
• Refinery gases • Tar	1601	11980
Total	**3563**	**25833**

Table 23: Net generation capacity (MW) of thermal power plants fuelled with industrial gases and waste.

5.2.2.1.3 Electrical efficiencies

The ranges of the average electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the different countries are reported in the following Table 24.

Technology	Efficiency [%]
Oil fired steam turbine	35 ÷ 36
Natural gas fired steam turbine	32 ÷ 38.8
Repowering	39.7
Hard coal fired steam turbine	33 ÷ 45
Lignite fired steam turbine	32 ÷ 35
Open cycle gas turbine	28.1 ÷ 37
Combined Cycle Gas Turbine	50 ÷ 60
Nuclear	30 ÷ 35

Table 24: Ranges of the electrical efficiencies (%) adopted for the different fossil fuelled generation technologies.

5.2.2.1.4 Unforced and scheduled unavailability

In the following Table 25, unforced (in p.u.) and scheduled (in days per year) average unavailability rates adopted for the different fossil fuelled generation technologies are reported.
As for nuclear generation, for each country, the average unavailability data of the last three years of operation (2006-2008) taken from the IAEA PRIS website [10] have been used.

Technology	Unavailability	
	Unforced [p.u.]	Scheduled [days]
Oil fired steam turbine	0.08	42
Natural gas fired steam turbine / Repowering	0.055	42
Old hard coal fired steam turbine	0.1	70
New hard coal fired steam turbine	0.06	35
Lignite fired steam turbine	0.113	70
Open cycle ad combined cycle gas turbine	0.05	35
Nuclear	0.001 ÷ 0.145	25

Table 25: Unforced (p.u.) and scheduled (days) unavailability rates adopted for the different fossil fuelled generation technologies.

As for the scheduled unavailability, a monthly distribution (shown in Table 26) of the planned outages as close as possible to reality has been adopted, by concentrating it in the months characterized by a lower load.

Month	Scheduled Unavailability Distribution [%]
January	8.41
February	8.80
March	9.98
April	9.04
May	8.85
June	6.60
July	5.13
August	8.99
September	9.07
October	9.79
November	8.15
December	7.19

Table 26: Distribution over the year of the scheduled unavailability adopted for the fossil fuelled generation technologies.

5.2.2.1.5 CO_2 emission rates of fossil fuels

In the following Table 27, CO_2 emission rates of the different fossil fuels adopted for the simulations are reported. Such data, together with plant efficiencies (see Table 24), allow to calculate CO_2 emission rates of the different generation technologies.

Fuel	Emission rate [tCO_2/GJ]
Fuel oil	0.077
Gas	0.056
Coal	0.094
Lignite	0.101

Table 27: CO_2 emission rates (tCO_2/GJ) of the different fossil fuels.

5.2.2.2 Hydro power plants

The MTSIM simulator can dispatch both reservoir and pumped storage hydro power plants, provided that, among others, data concerning the volumes of reservoirs / basins are defined. Since, for the different European countries, no information are available that allow to define the volumes of equivalent reservoirs / basins for their hydro power plants, it has been necessary to define and impose specific hourly production (as well as consumption, in case of pumped storage) profiles.
As for the monthly values of hydro energy production (or consumption) in each country, the average values of all the years available in the Statistical Database of the ENTSO-E website [2] have been taken into account.
More details are provided in the following.

5.2.2.2.1 Run of river hydro power plants

The hourly generation profile of run of river hydro power plants has been assumed flat and its level has been differentiated among the four seasons.
The generation capacity and the seasonal production assumed for the simulations in the different countries are reported in the following Table 28.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	5346	6233.2	7244.4	5263.4	4272.5	23013.5
BG	300	229.6	189.9	124.5	179.3	723.3
BL	125	37.5	33.1	32.8	38.9	142.3
BX	3277	3780.1	2331.6	2633.9	3659.0	12404.6
CH	3700	3568.1	5215.3	3712.8	3043.4	15539.6
CZ	200	86.1	55.2	54.6	69.1	265.0
DE	1109	1669.2	1724.4	1417.4	1417.0	6228.0
ES	4600	2802.0	2079.9	1716.6	2309.0	8907.5
FR	7600	9602.6	8050.4	6342.3	7657.2	31652.5
GR	120	50.8	46.4	30.6	45.4	173.2
HR	400	565.2	359.9	369.1	553.0	1847.2
HU	50	44.2	57.4	52.4	45.4	199.4
IT	4400	3906.0	4910.6	3627.6	3253.0	15697.2
NL	36	28.7	19.9	17.5	30.2	96.3
PL	377	476.9	337.8	349.4	414.7	1578.8
PT	2899	1413.1	850.1	969.7	1427.8	4660.7
RO	2619	2455.3	2391.3	1902.3	1892.2	8641.1
SI	986	775.0	832.4	685.8	501.1	2794.3
SK	1559	1097.4	856.7	620.3	747.4	3321.8
UA_W	27	50.8	30.9	24.0	28.1	133.8
Total	**39730**	**38872**	**37618**	**29947**	**31584**	**177182**

Table 28: Run of river hydro generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries.

5.2.2.2.2 Reservoir and pumped storage hydro power plants

In order to define the hourly production (and consumption) profiles of reservoir and pumped storage hydro power plants, it has been assumed that they can generate at least between 6:00 and 23:00 and that they can pump only between 23:00 and 6:00.
As for the consumption of pumped storage plants, the hourly profile has been considered flat and its level has been differentiated among the four seasons.
The generation capacity and the seasonal consumption of pumped storage hydro power plants assumed for the simulations in the different countries are reported in the following Table 29.

Country	Net generation capacity [MW]	Electricity consumption [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	8631	745.8	846.2	816.0	792.5	3200.5
BG	1010	133.3	109.5	166.3	161.9	571.0
BL	2604	688.4	682.0	684.1	693.6	2748.1
BX	1162	280.8	338.1	498.8	306.2	1423.9
CH	2000	582.2	933.2	580.9	438.5	2534.8
CZ	1100	172.6	139.7	191.7	228.7	732.7
DE	8300	2044.1	2203.1	2330.1	2316.5	8893.8
ES	6844	1108.3	1194.0	1242.8	1380.3	4925.4
FR	4200	1845.7	1324.7	1872.1	2039.9	7082.4
GR	699	213.8	220.2	266.3	245.1	945.4
HR	300	35.4	48.9	45.9	51.0	181.2
IT	7091	2091.7	1920.4	2102.7	2195.6	8310.4
PL	1785	289.2	298.8	354.8	376.1	1318.9
PT	2229	135.2	139.1	163.7	175.1	613.1
RO	250	57.3	39.9	26.8	17.0	141.0
SI	180	46.4	52.2	50.3	49.1	198.0
SK	907	54.1	43.1	56.1	63.6	216.9
Total	**49292**	**10524**	**10533**	**11449**	**11531**	**53653**

Table 29: Pumped storage hydro generation capacity (MW) and seasonal consumption (GWh) assumed for the simulations in the different countries.

As for the reservoir and pumped storage hydro power plants (that we will call “dispatchable hydro”), three different cases have been considered in order to determine their imposed production profile.

The first case takes place when dispatchable hydro production, compared to the other productions, is not very high, so that it is assumed to cover part of the daily load only from 6:00 to 23:00. In this case, the daily production is allocated proportionally to the difference of the hourly load values and the values corresponding to the line connecting the 5:00 and the 23:00 load values (see Figure 4).

The second case takes place when dispatchable hydro production, compared to the other productions, is relevant. In this case, the daily production is allocated proportionally to the difference of the hourly load values and the values corresponding to the line passing through the minimum daily load, that, in the vast majority of cases, occurs in the early hours of the morning (see Figure 5).

The third case takes place when dispatchable hydro production, compared to the other productions, is very high. In this case, the daily production is allocated proportionally to the difference of the hourly load values and the values corresponding to a line passing below the minimum daily load. In this case, dispatchable hydro production operates continuously all day long (see Figure 6).

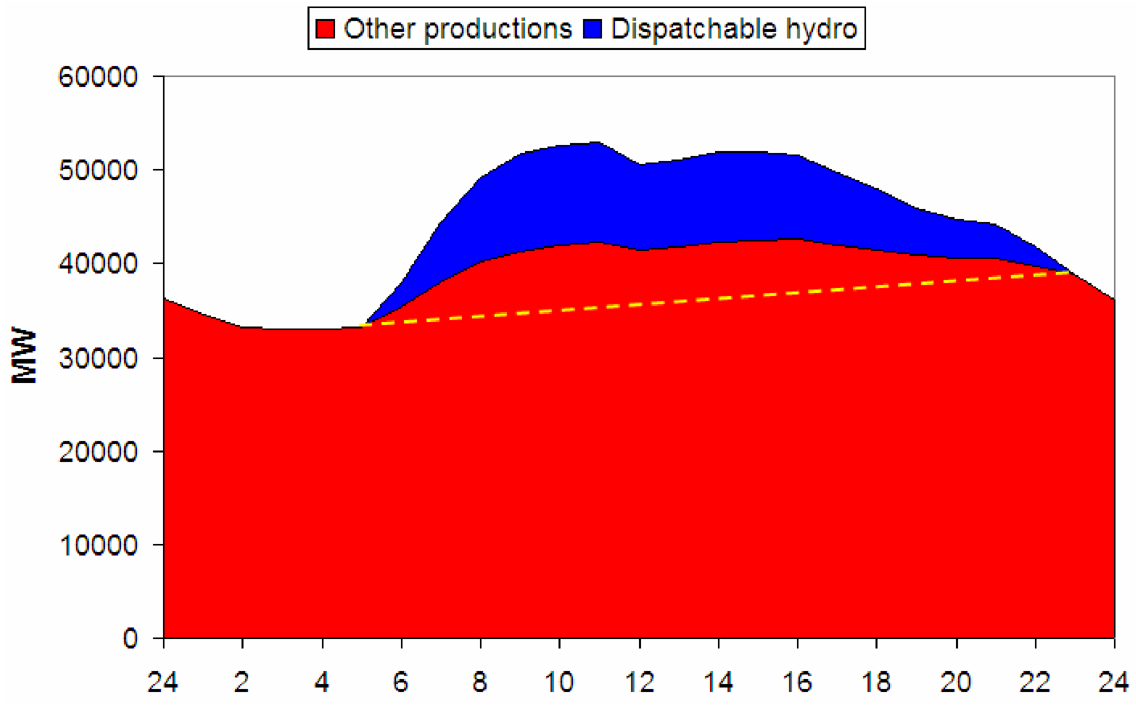

Figure 4: Hourly profile of dispatchable hydro – first case.

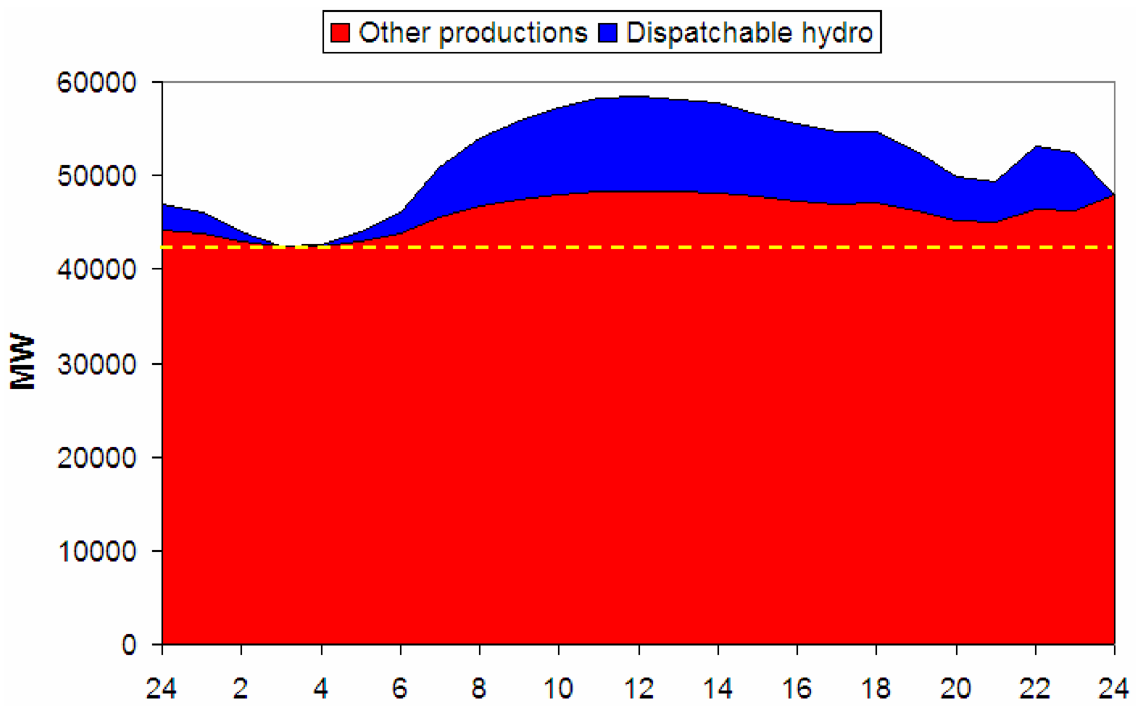

Figure 5: Hourly profile of dispatchable hydro – second case.

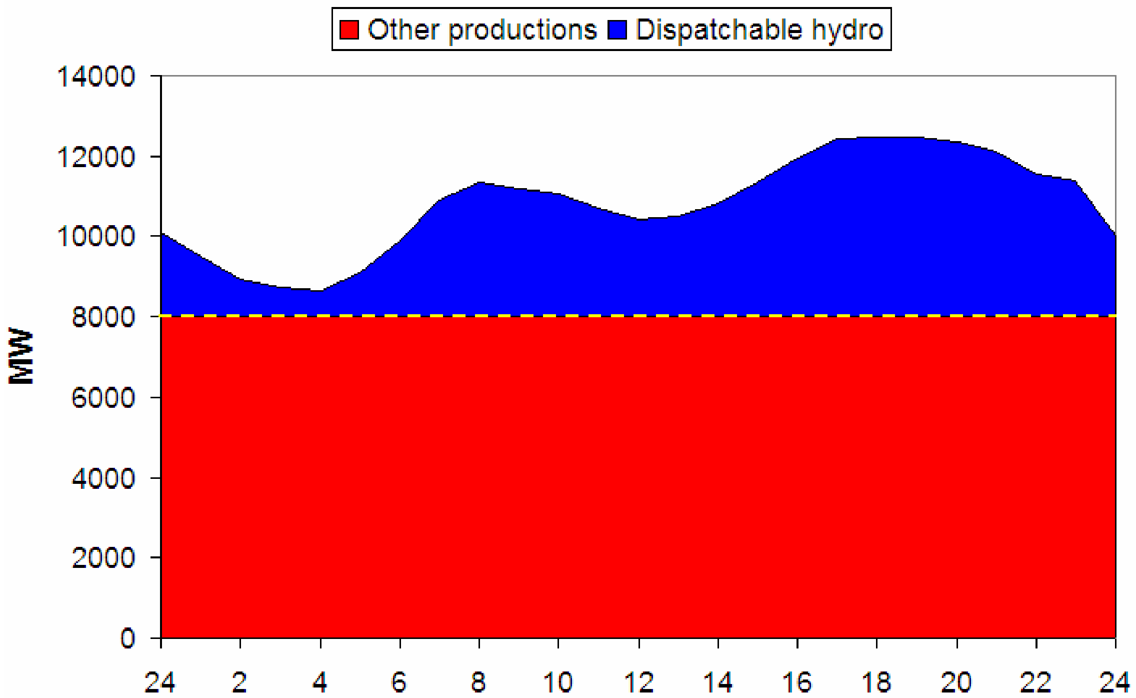

Figure 6: Hourly profile of dispatchable hydro – third case.

Of course, in all these cases, it must be verified that the maximum hourly value of the allocated dispatchable hydro production does not exceed the maximum generation capacity of both reservoir and pumped storage hydro power plants in the considered country.
The generation capacity and the seasonal production of dispatchable hydro power plants assumed for the simulations in the different countries are reported in the following Table 30.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	8631	3331.8	3873.6	2814.8	2283	12303.2
BG	2640	1004.4	827.9	537	787	3156.3
BL	2621	631.7	560.4	563.5	659.4	2415
BX	3861	3048	1524	2134.7	3362.6	10069.3
CH	9900	4422.9	6470.4	4606.7	3772.6	19272.6
CZ	1900	821.4	532.8	519.1	646.6	2519.9
DE	8300	4732.5	4883.3	4021.6	4015.3	17652.7
ES	18006	5587.6	4143.3	3423.1	4598.2	17752.2
FR	17800	9209.7	7719.4	6082.9	7341.5	30353.5
GR	3199	1326.5	1189.1	793.2	1192.4	4501.2
HR	1900	1129.3	719.1	732.1	1103.3	3683.8
IT	17000	6638.5	8345.9	6166.6	5524.8	26675.8
PL	1950	407.6	288.4	295.1	354	1345.1
PT	3835	1121.6	675.4	766.5	1132.2	3695.7
RO	3571	2539.4	2473.2	1965.7	1957.1	8935.4
SI	180	88.2	94.8	77	55.5	315.5
SK	907	371.1	291.5	209.7	253.2	1125.5
Total	**106201**	**46412**	**44613**	**35709**	**39039**	**165773**

Table 30: Dispatchable hydro generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries.

5.2.2.3 Renewable energy power plants

Since renewable energy power plants are in most cases non dispatchable, specific hourly production profiles have been defined and imposed in the simulations, adopting different assumptions according to the operating characteristics of the generation technologies considered, as reported in the following paragraphs.

5.2.2.3.1 Wind power plants

As for wind power plants, data concerning the equivalent full-load annual hours and the seasonal distribution of production, for each country, have been taken from the ENCOURAGED project (see [8]), while the installed capacity for year 2015, as above mentioned, is the one foreseen in the ENTSO-E *System Adequacy Forecast (SAF) 2009-2020* (available from [2]). The annual electricity production is therefore calculated as the product of the equivalent full-load annual hours times the installed capacity.
Moreover, a flat generation profile for each season has been defined.
The generation capacity and the seasonal production of wind power plants assumed for the simulations in the different countries are reported in the following Table 31.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	1555	921	921	911	901	3654
BG	650	306	229	344	344	1223
BL	2124	1525	1525	1509	1492	6051
BX	170	85	85	85	85	340
CZ	700	332	332	329	325	1318
DE	40517	16553	10349	15964	23352	66218
ES	28000	16232	16232	16056	15879	64399
FR	7000	4363	4363	4316	4268	17310
GR	2500	1191	1191	1179	1166	4727
HR	600	280	200	240	280	1000
HU	330	163	163	162	160	648
IT	4900	2262	1154	1428	1902	6746
NL	4908	3336	2274	3036	5031	13677
PL	1075	522	522	517	511	2072
PT	4900	2796	2117	2525	3046	10484
RO	740	356	329	329	356	1370
SI	50	22	17	22	28	89
SK	200	96	96	95	94	381
Total	**100919**	**51341**	**42099**	**49047**	**59220**	**201707**

Table 31: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries.

5.2.2.3.2 Photovoltaic solar power plants

The generation capacity (taken from the ENTSO-E *System Adequacy Forecast (SAF) 2009-2020*, except for Italy) and the annual production (data for each installed kW at optimal inclination taken from the *Photovoltaic Geographical Information System* (PVGIS) of the JRC - *Joint Research Centre* [11]) of photovoltaic solar power plants assumed for the simulations in the different countries are reported in the following Table 32.

Country	Net generation capacity [MW]	Electricity production [GWh]
BG	130	143
BL	54	45.4
DE	4000	3440
ES	4500	6075
FR	500	550
IT	2646	3245
GR	700	892.5
NL	60	50.7
PT	88	121
SK	10	9.5
Total	**12688**	**14572**

Table 32: Photovoltaic solar generation capacity (MW) and annual production (GWh) assumed for the simulations in the different countries.

As for the definition of the hourly generation profiles in the different countries and in the different months, the following data have been taken into account:

- the average daily hours of light in each month (see [11]);
- the average daily electricity production in each month with an optimal inclination of PV panels, provided by the PVGIS *Solar Irradiance Data* utility (see [12]).

Then, the average daily production in each month has been profiled according to a sinusoidal trend along the corresponding hours of light.
For example, in Figure 7 production profiles of a 1 kWp plant located in Rome (Italy) and installed with an optimal inclination of 34° are shown.

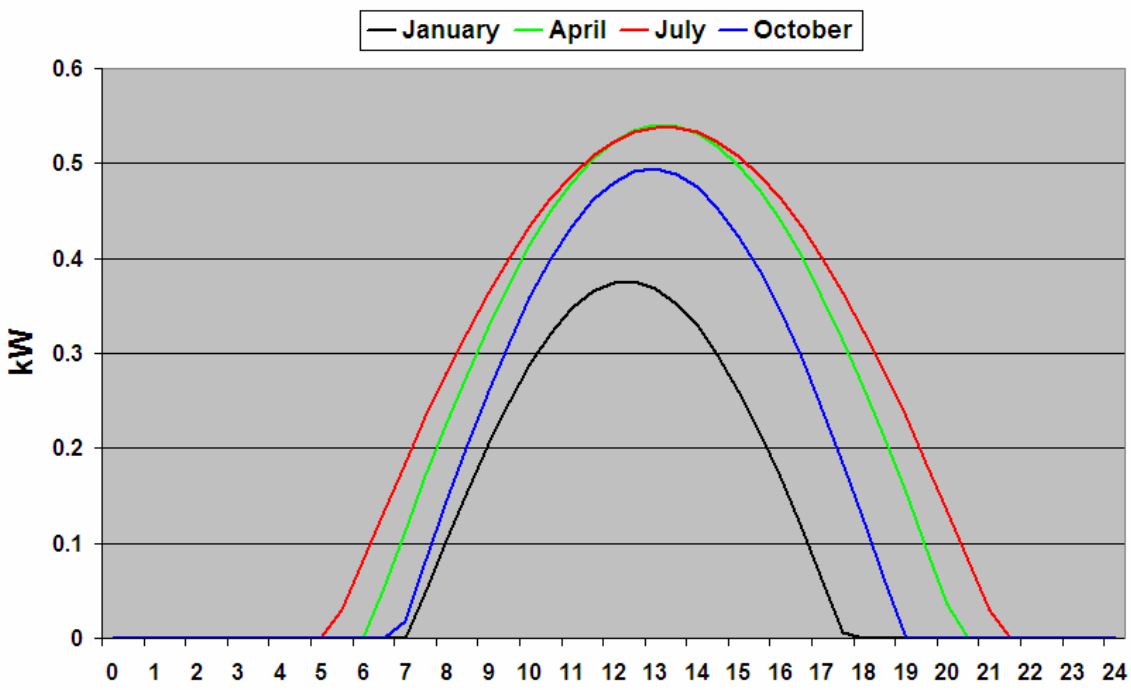

Figure 7: Example of daily production profiles of a 1 kWp photovoltaic solar power plant installed in Rome (Italy) with an optimal inclination of 34°.

5.2.2.3.3 Other RES + waste

To estimate the electricity production of other renewable energy sources (biomass, biogas, geothermal, etc.) and of waste power plants, that in the ENTSO-E *System Adequacy Forecast (SAF) 2009-2020* are all included in the item named "Other RES", a value of 4500 equivalent full-load annual hours has been taken into account[27]. Moreover, a flat generation profile has been assumed.
The generation capacity and the annual production of "Other RES" power plants assumed for the simulations in the different countries are reported in the following Table 33.

[27] A more detailed estimation for each source has been carried out for Italy.

Country	Net generation capacity [MW]	Electricity production [GWh]
AT	300	1350
BL	889	4000
CH	400	1799
DE	8757	39403
ES	1700	7653
FR	1200	5399
GR	800	3600
HR	100	450
HU	700	3151
IT	2370	14179
NL	240	1080
PL	172	774
PT	587	2640
SK	110	495
Total	**18325**	**85973**

Table 33: “Other RES” generation capacity (MW) and annual production (GWh) assumed for the simulations in the different countries.

5.2.3 Other scenario assumptions

As for the other main scenario assumptions, in most cases they have been derived from the POLES scenario *"GR-FT Global Regime with Full Trade"*, as reported in the following.
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 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.

5.2.3.1 Fuel prices

Oil, coal and gas prices have been directly taken from the GR-FT scenario.
Lignite and fuel oil prices have been calculated as indexed to coal and oil prices, respectively.
The nuclear fuel price has been derived by the POLES scenario's fuel costs of nuclear generation, assuming an average electrical efficiency of 34,2%.

Fuel	Price [€/GJ]
Coal	1.936
Lignite	0.871
Gas	5.076
Fuel Oil	8.358
Nuclear	0.428

Table 34: Fuel prices assumed for year 2015 in the simulations.

5.2.3.2 CO_2 emissions value

The CO_2 emissions value for year 2015 is 13.25 €/tCO_2, as in the GR-FT scenario.

5.2.3.3 Electrical load

The annual values of the 2015 electrical load (final consumptions plus network losses; pumped storage consumption not included: see paragraph 5.2.2.2.2) of each considered

European country, except Switzerland, Slovenia and Ukraine West (whose data were not available), have been taken from the GR-FT scenario.
Since the overall 2015 load of the considered countries is quite similar to the 2008 one, for Switzerland, Slovenia and Ukraine West the 2015 load has been assumed equal to the 2008 one.
The considered annual load values are reported in the following Table 35.

Country	Final consumption + network losses [GWh]		
	2008	2015	∆%
AT	68378	63008	-7.85
BG	34453	34669	+0.63
BL	96136	95932	-0.21
BX	71361	70665	-0.98
CH	64434	64434	0.00
CZ	65142	66154	+1.55
DE	578872	574779	-0.71
ES	270914	293124	+8.20
FR	494503	485781	-1.76
GR	56311	65020	+15.47
HR	17861	17687	-0.98
HU	41284	38158	-7.57
IT	339484	318215	-6.27
NL	120195	118559	-1.36
PL	142854	133106	-6.82
PT	52178	55102	+5.60
RO	55207	51247	-7.17
SI	12686	12686	0.00
SK	27636	25930	-6.17
UA_W	4155	4155	0.00
Total	**2614046**	**2588412**	**-0.98**

Table 35: 2008 and 2015 annual electrical load values for the considered countries.

As for the hourly profile, each country’s 2008 profile has been taken from the ENTSO-E Statistical Database (see [2]), then it has been scaled according to the 2015 / 2008 annual load ratio. The last step has been to align the working days and the holidays of 2015 with those of 2008.

5.2.3.4 VOLL (Value Of Lost Load)

As reported in [13], VOLL estimation is a very difficult task and the results obtained are subject to several uncertainties. On the basis of the broad ranges and on the considerations reported in [13], we decided to subdivide the European countries taken into account into three groups:

- totally developed countries, characterized by a 20 €/kWh VOLL value;
- developed countries which still have growth margins higher than those included in the first group, characterized by a 10 €/kWh VOLL value;

- developing countries, characterized by a 3,5 €/kWh VOLL value.

Since the MTSIM simulator does not allow to specify VOLL values for each country, a single "European" VOLL value has been determined calculating the average of each country's value, weighted on the corresponding 2015 electrical load.
With these assumptions, the resulting VOLL value is equal to 15.5 €/kWh.
In any case, it must be taken into account that the precision of the definition of such a value is definitely not critical for the results of the simulations: it is sufficient to get the right order of magnitude.

5.3 Results of the simulations

MTSIM has been used to simulate the optimal behavior of the modeled power system, having as objective function the cost (fuel and CO_2) minimization. No market power exercise has been simulated, in order to focus on the "natural" best response of the power system to the considered shortages.
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).

5.3.1 Italy

In the following Table 36, a comparison between gas consumption for power generation in the "base case" and the estimated amount of available gas (see Table 6) 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 36: 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 6) 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. In particular, the "repowering" units (see Table 17) are fuelled with fuel-oil instead of gas, therefore their maximum power is reduced from 4848 to 3364 MW (the open cycle gas turbines are not operated), and also their efficiency is reduced.
Finally, a constant import of 500 MW (the NTC value) from the Italy-Greece DC interconnector is assumed.
In the following Table 37 a comparison between gas consumption of non-CHP thermal power plants in the "base case" and in the "shortage case" is reported.

Month	Gas consumption [TJ]		Gas consumption [Mcm]		Δ%
	Base	Shortage	Base	Shortage	
November	35.78	22.32	1036	646	-37.6
December	39.10	0	1132	0	-100.0
January	54.47	15.71	1577	455	-71.2
February	63.26	42.6	1832	1234	-32.7
March	40.34	7.44	1168	215	-81.6
Nov - Mar	**232.95**	**88.07**	**6745**	**2551**	**-62.2**

Table 37: Comparison between gas consumption of non-CHP thermal power plants in the "base case" and in the "shortage case".

Under these conditions and assuming not to use the strategic gas storage for non-CHP thermal power plants[28], a criticality shows up only in December (the month with the greatest lack of gas: see Table 36), when the modeled power system is not able to supply **349.5 GWh**, i.e. about 1.38% of the monthly load.
In particular, the most of such energy not supplied (ENS) occurs in the first part of the month, characterized by a higher load, as shown in the following Table 38.

Week	Maximum load value [MW]	ENS [GWh]
Mon 1 – Sun 7	49426	117.3
Mon 8 – Sun 14	50674	152.9
Mon 15 – Sun 21	48909	77.7
Mon 22 – Sun 28	42936	0
Mon 29 – Wed 31	44922	1.6
Total		**349.5**

Table 38: Energy not supplied in December, in the "shortage case".

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.

[28] **92 Mcm** of strategic gas storage are necessary in December to keep all CHP gas-fired power plants in operation.

Moreover, it can be seen that the neighbouring generation systems do their best to help Italy to tackle with 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.

In the following a more detailed comparison between the "base case" and the "shortage case" (with energy not supplied) is reported.

5.3.1.1 Italian thermal generation

In the following Table 39, a comparison between non-CHP thermal generation in Italy in the "base case" and in the "shortage case" is reported: in the five months when the shortage occurs generation decreases by about 12.5 TWh, that is 20.9%. Of course, apart from the energy not supplied, this corresponds to an equivalent increase of imported energy.

Month	Non-CHP thermal generation [GWh]			
	base case	shortage case	Δ	Δ%
November	10444.3	8647.0	-1797.3	-17.2
December	11188.0	7864.8	-3323.2	-29.7
January	13347.6	10579.0	-2768.6	-20.7
February	13908.1	11280.9	-2627.2	-18.9
March	11079.7	9048.3	-2031.4	-18.3
Nov - Mar	**59967.7**	**47420.0**	**-12547.7**	**-20.9**

Table 39: Comparison between non-CHP thermal generation in Italy in the "base case" and in the "shortage case".

From Figure 8 we can notice in the "shortage case" a dramatic decrease of CCGT generation, as well as a significant increase of production by fuel-oil fired power plants, that in the "base case" do not operate, due to their higher production costs.

In terms of fuel consumption, the comparison between the two cases is reported in Figure 9.

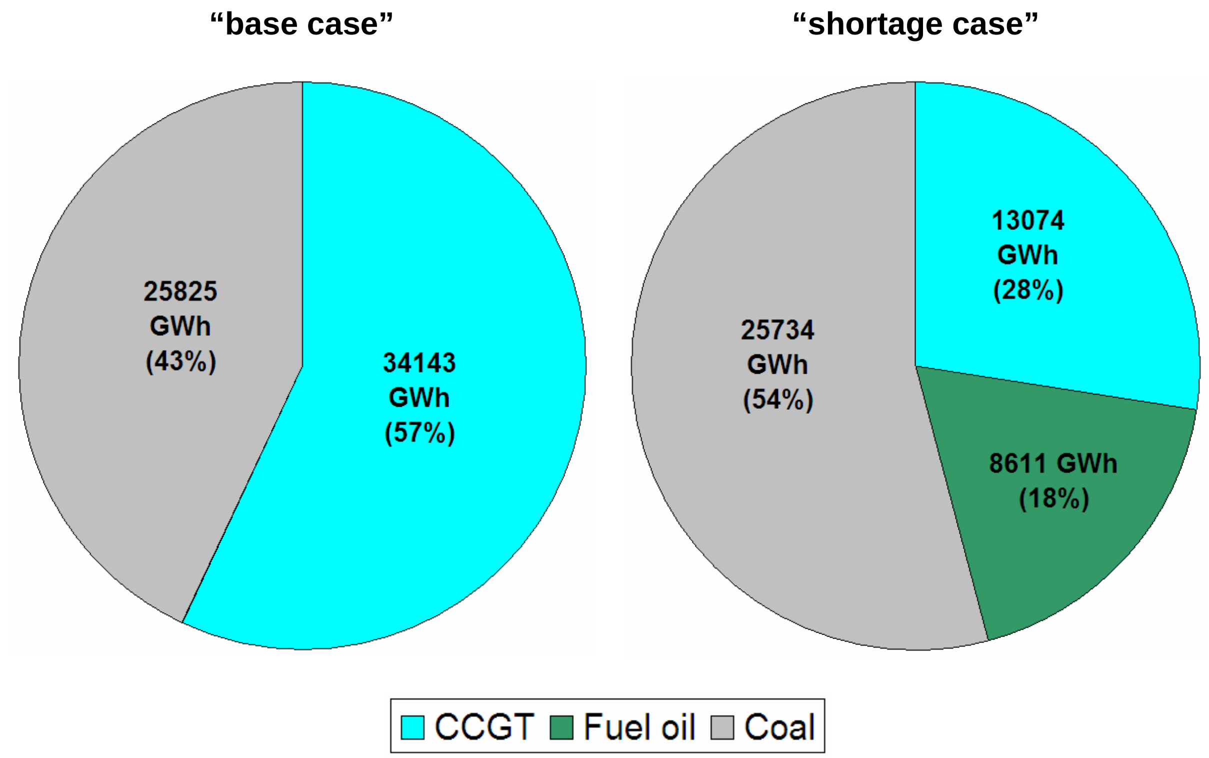

Figure 8: Comparison between non-CHP thermal generation (in GWh) in Italy in the "base case" and in the "shortage case".

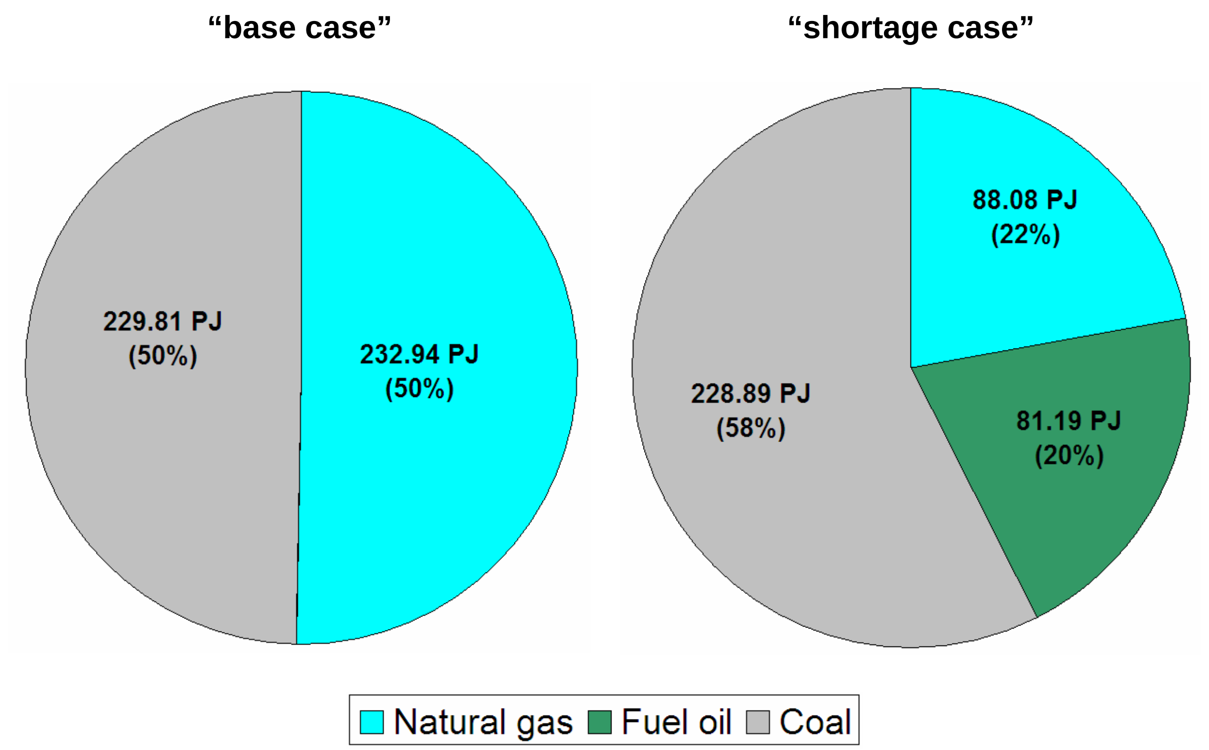

Figure 9: Comparison between non-CHP thermal plants fuel consumption (in PJ) in Italy in the "base case" and in the "shortage case".

5.3.1.2 Italian neighboring countries

5.3.1.2.1 France

In the “shortage case”, electricity imports from France double, while electricity exports to France almost disappear (see Table 40).
Moreover, the electricity generated by non-CHP thermal plants in France slightly increases.

Non–CHP thermal generation			**FR → IT**			**IT → FR**		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
205250.9	210848.7	**5597.8**	3688.9	7203.3	**3514.4**	640.8	29.7	**-611.1**

Table 40: Non-CHP thermal generation in France and electricity exchanges with Italy in the “base case” and in the “shortage case” (GWh).

5.3.1.2.2 Switzerland

In the “shortage case”, electricity imports from Switzerland more than double, while electricity exports to Switzerland almost disappear (see Table 41).
Moreover, the electricity generated by non-CHP thermal plants in Switzerland basically remains the same: in fact, Switzerland acts as a transit country that allows Italy to import energy generated in other countries.

Non–CHP thermal generation			**CH → IT**			**IT → CH**		
Base	Shortage	Δ	Base	Short.	Δ	Base	Sho.	Δ
10947.5	10997.6	**50.1**	2515.7	5670.8	**3155.1**	1110.3	51.4	**-1058.9**

Table 41: Non-CHP thermal generation in Switzerland and electricity exchanges with Italy in the “base case” and in the “shortage case” (GWh).

5.3.1.2.3 Austria

In the “shortage case”, electricity imports from Austria double, while electricity exports to Austria almost disappear (see Table 42).
On the other hand, the electricity generated by non-CHP thermal plants in Austria is decreased by the simulator, in order to maximize Italian imports from both Austria and Slovenia, taking into account the PTDF structure of the network (see paragraph 5.2.1).

Non-CHP thermal generation			AT → IT			IT → AT		
Base	Shortage	Δ	Base	Shortage	ΔE	Base	Shortage	Δ
8115.7	6860.4	**-1255.3**	338.4	712.2	**373.8**	100.3	3.7	**-96.6**

Table 42: Non-CHP thermal generation in Austria and electricity exchanges with Italy in the "base case" and in the "shortage case" (GWh).

5.3.1.2.4 Slovenia

In the "shortage case", electricity imports from Slovenia more than double, while electricity exports to Slovenia almost disappear (see Table 43).
Moreover, the electricity generated by non-CHP thermal plants in Slovenia increases.

Non–CHP thermal generation			SI → IT			IT → SI		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
5179.8	5989.6	**809.8**	875.6	1950.7	**1075.1**	135.1	9.6	**-125.5**

Table 43: Non-CHP thermal generation in Slovenia and electricity exchanges with Italy in the "base case" and in the "shortage case" (GWh).

5.3.1.2.5 Greece

In the "shortage case", electricity imports from Greece increase dramatically, while electricity exports to Greece disappear (see Table 44), having imposed the saturation of the 500 MW DC interconnector from Greece to Italy.
Moreover, the electricity generated by non-CHP thermal plants in Greece increases to tackle with the increased exports.

Non–CHP thermal generation			GR → IT			IT → GR		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
18515.6	20833.3	**2317.7**	48.3	1812.0	**1763.7**	924.5	0.00	**-924.5**

Table 44: Non-CHP thermal generation in Greece and electricity exchanges with Italy in the "base case" and in the "shortage case" (GWh).

5.3.1.3 Overall system thermal generation

In the following Table 45 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 46). 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 paragraph 6.4), 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 45: 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 46: Comparison between fuel consumption of non-CHP plants in the modeled power system in the "base case" and in the "shortage case" (PJ).

5.3.1.4 CO_2 emissions

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 (see Table 39) 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).
Emission data by fuel are summarized in the following Figure 13 (bracketed data in the "shortage case" pie represent the variations w.r.t. the "base case").

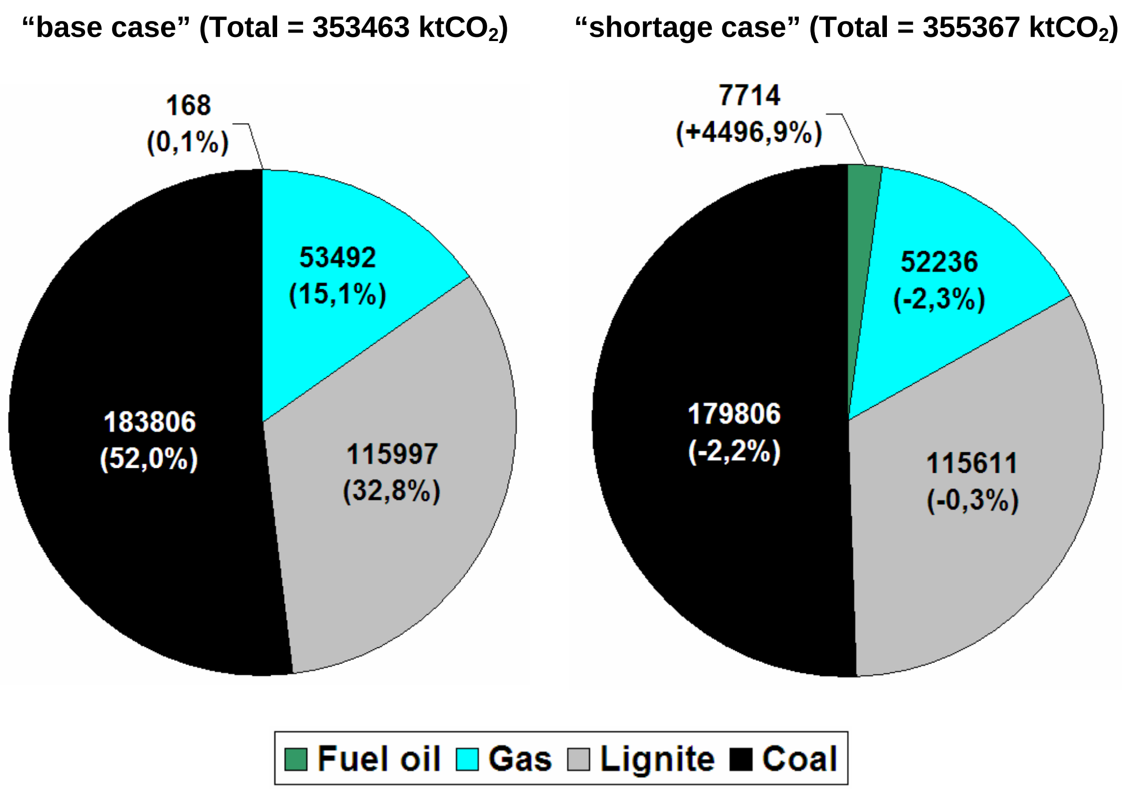

Figure 10: CO_2 emissions of the non-CHP power plants in the modeled power system in the "base case" and in the "shortage case" (ktCO_2).

5.3.1.5 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 47, 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 47: Extra-costs borne by the modeled power system due to the gas shortage in Italy.

5.3.2 Hungary

In the following Table 48, a comparison between gas consumption for power generation in the “base case” and the estimated amount of available gas (see paragraph 3.2.3) 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 48: 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. 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 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.
In the following Table 49 a comparison between gas consumption of non-CHP thermal power plants in the “base case” and in the “shortage case” is reported.

Month	Gas consumption [TJ]		Gas consumption [Mcm]		Δ%
	Base	Shortage	Base	Shortage	
November	0.55	0	15.96	0	-100
December	0.46	0	13.19	0	-100
January	1.55	0	44.77	0	-100
February	2.93	0	84.73	0	-100
March	0.21	0	6.19	0	-100
Nov - Mar	**5.70**	**0**	**164.84**	**0**	**-100**

Table 49: Comparison between gas consumption of non-CHP thermal power plants in the "base case" and in the "shortage case".

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 neighbouring generation systems do their best to help Hungary providing it with more energy.

In the following a more detailed comparison between the "base case" and the "shortage case" is reported.

5.3.2.1 Hungarian thermal generation

In the following Table 50, a comparison between non-CHP thermal generation in Hungary in the "base case" and in the "shortage case" is reported: in the five months when the shortage occurs generation decreases by about 0.7 TWh, that is 7.7%. Of course, this corresponds to an equivalent increase of imported energy.

Month	Non-CHP thermal generation [GWh]			
	base case	shortage case	Δ	Δ%
November	1765.7	1694.1	-71.6	-4.1
December	1816.0	1755.3	-60.7	-3.3
January	1973.7	1779.9	-193.8	-9.8
February	1950.6	1594.3	-356.3	-18.3
March	1745.5	1714.9	-30.6	-1.8
Nov - Mar	**9251.6**	**8538.5**	**-713.1**	**-7.7**

Table 50: Comparison between non-CHP thermal generation in Hungary in the "base case" and in the "shortage case".

From Figure 11 we can notice that in the "shortage case" natural gas generation does not produce and its lack is compensated mostly by greater imports.

In terms of fuel consumption, the comparison between the two cases is reported in Figure 12.

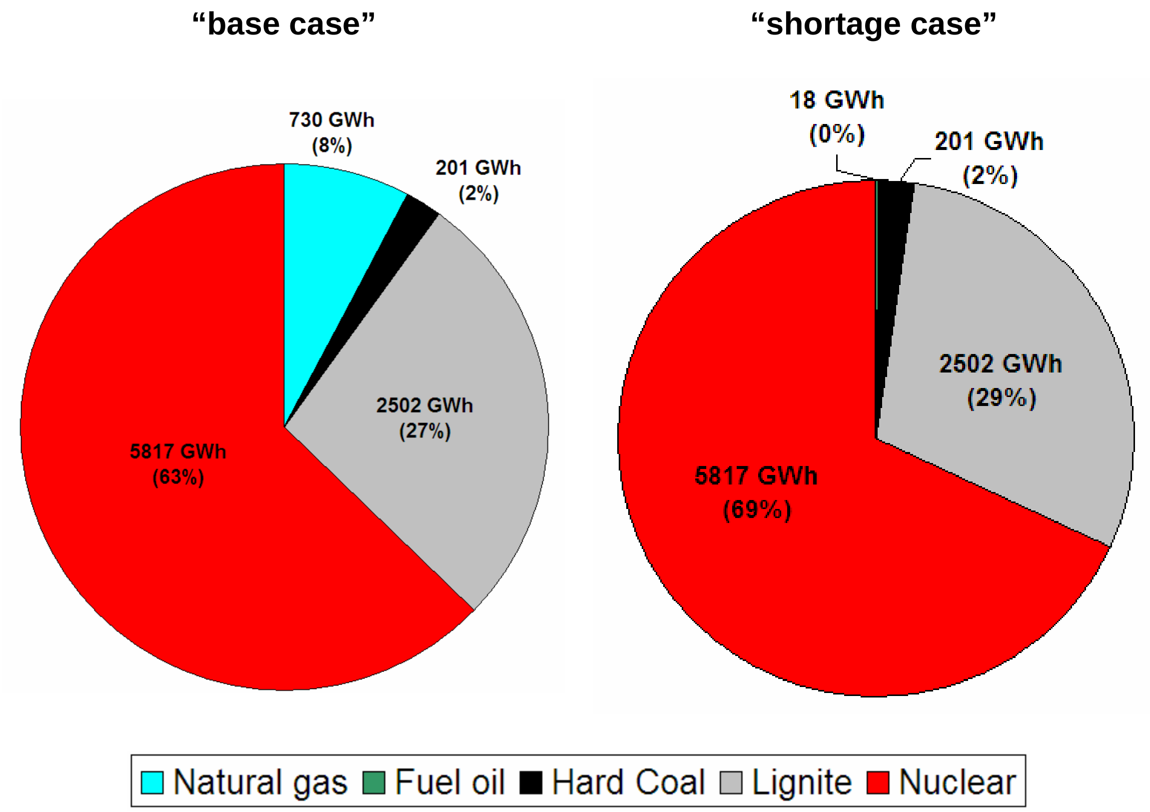

Figure 11: Comparison between non-CHP thermal generation (in GWh) in Hungary in the "base case" and in the "shortage case".

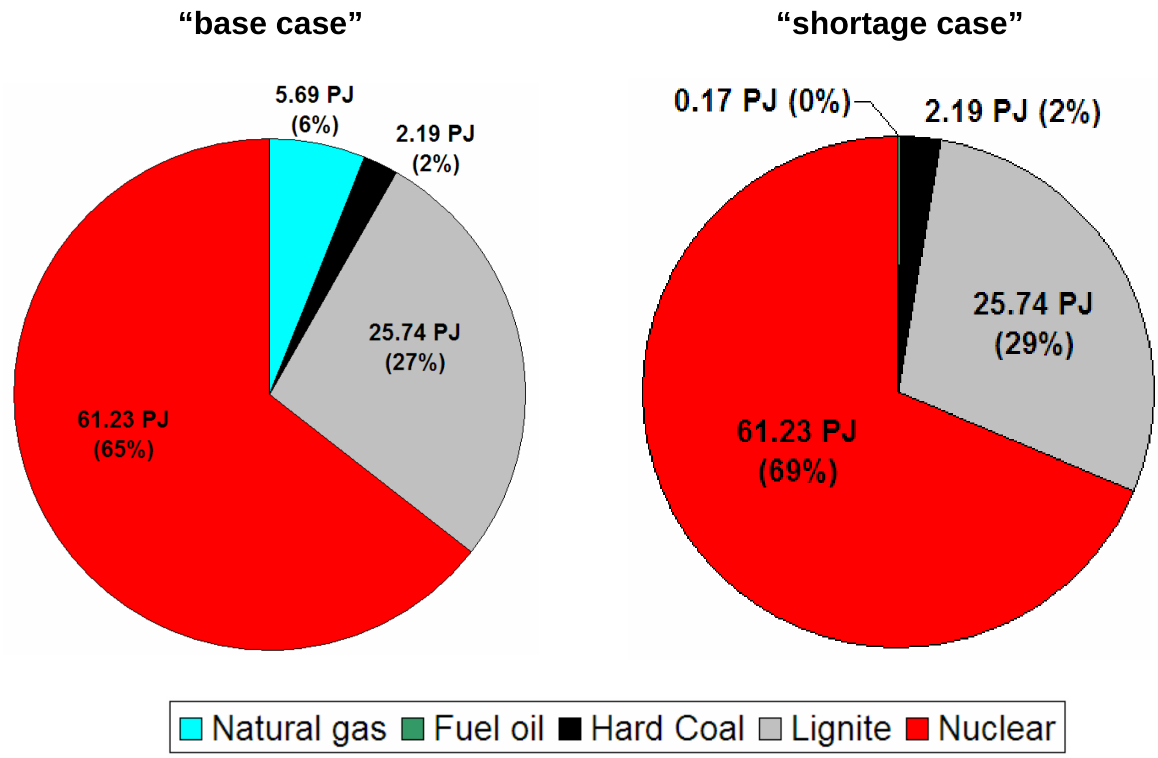

Figure 12: Comparison between non-CHP thermal plants fuel consumption (in PJ) in Hungary in the "base case" and in the "shortage case".

5.3.2.2 Hungarian neighboring countries

5.3.2.2.1 Austria

In the “shortage case”, electricity imports from Austria slightly increase, while electricity exports to Austria decrease (see Table 51).
Moreover, the electricity generated by non-CHP thermal plants in Austria slightly decreases, resorting to imports from other countries.

Non–CHP thermal generation			AT → HU			HU → AT		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
8115.7	8055.2	**-60.5**	9.1	28.9	**19.8**	1217.4	1141.9	**-75.5**

Table 51: Non-CHP thermal generation in Austria and electricity exchanges with Hungary in the “base case” and in the “shortage case” (GWh).

5.3.2.2.2 Balkan countries

In the “shortage case”, electricity imports from the aggregated Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia, Serbia) increase, while electricity exports to such countries slightly decrease (see Table 52).
Moreover, the electricity generated by non-CHP thermal plants in the Balkan countries increases.

Non–CHP thermal generation			BX → HU			HU → BX		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
11925.2	11997.6	**72.4**	609.9	712.1	**102.2**	180.7	179.7	**-1.0**

Table 52: Non-CHP thermal generation in the Balkan countries and electricity exchanges with Hungary in the “base case” and in the “shortage case” (GWh).

5.3.2.2.3 Croatia

In the “shortage case”, electricity imports from Croatia increase, while electricity exports to Croatia decrease (see Table 53).
Moreover, the electricity generated by non-CHP thermal plants in Croatia increases.

Non–CHP thermal generation			HR → HU			HU → HR		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
1862.8	1909.6	**46.8**	142.7	228.1	**85.4**	708.6	669.2	**-39.4**

Table 53: Non-CHP thermal generation in Croatia and electricity exchanges with Hungary in the "base case" and in the "shortage case" (GWh).

5.3.2.2.4 Romania

In the "shortage case", electricity imports from Romania increase, while electricity exports to Romania decrease (see Table 54).
Moreover, the electricity generated by non-CHP thermal plants in Romania increases.

Non–CHP thermal generation			RO → HU			HU → RO		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
11116.6	11264.8	**148.2**	544.5	633.0	**88.5**	79.5	62.8	**-16.7**

Table 54: Non-CHP thermal generation in Romania and electricity exchanges with Hungary in the "base case" and in the "shortage case" (GWh).

5.3.2.2.5 Slovak Republic

In the "shortage case", electricity imports from the Slovak Republic increase, while electricity exports to the Slovak Republic decrease (see Table 55).
Moreover, the electricity generated by non-CHP thermal plants in the Slovak Republic slightly increases.

Non–CHP thermal generation			SK → HU			HU → SK		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
8453.1	8458.3	**5.2**	1699.1	1763.4	**64.3**	178.5	47.0	**-131.5**

Table 55: Non-CHP thermal generation in the Slovak Republic and electricity exchanges with Hungary in the "base case" and in the "shortage case" (GWh).

5.3.2.2.6 Ukraine West

In the "shortage case", electricity imports from the Ukraine West increase, while electricity exports to the Ukraine West slightly decrease (see Table 56).
Moreover, the electricity generated by non-CHP thermal plants in the Ukraine West increases.

Non–CHP thermal generation			UA_W → HU			HU → UA_W		
Base	Shortage	Δ	Base	Short.	Δ	Base	Short.	Δ
3303.0	3393.6	**90.6**	1332.2	1456.7	**124.5**	15.7	13.9	**-1.8**

Table 56: Non-CHP thermal generation in the Ukraine West and electricity exchanges with Hungary in the “base case” and in the “shortage case” (GWh).

5.3.2.3 Overall system thermal generation

In the following Table 57 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 58).

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 57: 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 58: Comparison between fuel consumption of non-CHP plants in the modeled power system in the “base case” and in the “shortage case” (PJ).

5.3.2.4 CO_2 emissions

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 (see Table 50) 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).
Emission data by fuel are summarized in the following Figure 13 (bracketed data in the "shortage case" pie represent the variations w.r.t. the "base case").

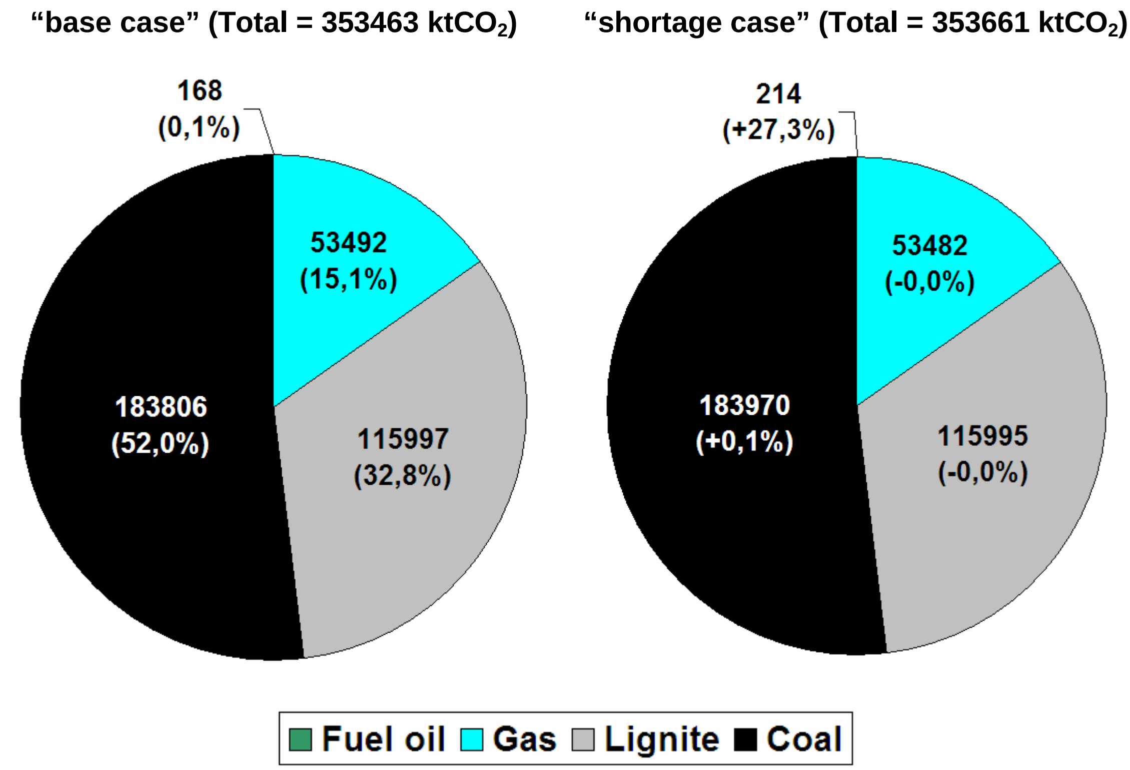

Figure 13: CO_2 emissions of the non-CHP power plants in the modeled power system in the "base case" and in the "shortage case" (ktCO_2).

5.3.2.5 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 59, 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 59: Extra-costs borne by the modeled power system due to the gas shortage in Hungary.

6 Step 5: remedies assessment

Remedies to tackle with 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.

6.1 Short-term remedies in the gas sector

- *Maximize imports from the remaining supply sources*

The most natural remedy to tackle (at least partially) with 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 in chapter 5.
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.

6.2 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 (see also [14]).
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.

6.3 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 5.3.1.5 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.

6.4 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 will be analyzed in more detail in SECURE Deliverable 5.6.1: *"Optimization of transmission infrastructure investments in the EU power sector"*, 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 60).

Interconnection	"shortage case" [GWh]	"unconstrained" [GWh]	Δ%
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 60: 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 substitutes not only fuel oil-fired, but also gas-fired generation, as shown in Table 61. The corresponding results in terms of fuel consumptions are shown in Table 62.

Fuel	"shortage case" [GWh]	"unconstrained" [GWh]	Δ%
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 61: 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]	Δ%
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 62: 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 63, 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.

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

Table 63: 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.

7 Step 6: how remedies should be financed / paid for

7.1 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.

7.2 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.
Financial structures of these projects can be quite complex, resorting to different combinations of financing sources. For example, Figure 14 shows the possible financing sources for large LNG projects (see [15]), where:

- ECA stands for *Export Credit Agency*, i.e. a governmental agency that aims at facilitating the financing of a project in order to promote the commercial interests of its nation in line with the policies of the government;
- MLA stands for *MultiLateral Agency*, made up of members from a multiplicity of participating countries and having a constitutional goal of encouraging investment in developing countries in line with certain policy criteria; examples are the International Finance Corporation (IFC), the private investment arm of the World Bank, The European Bank of Reconstruction and Development and the Asian Development Bank;
- IFA stands for *Individual Facility Agreement*, while CTA stands for *Common Terms Agreement*, which refer to the definition of financing terms applicable to all the parties.

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.

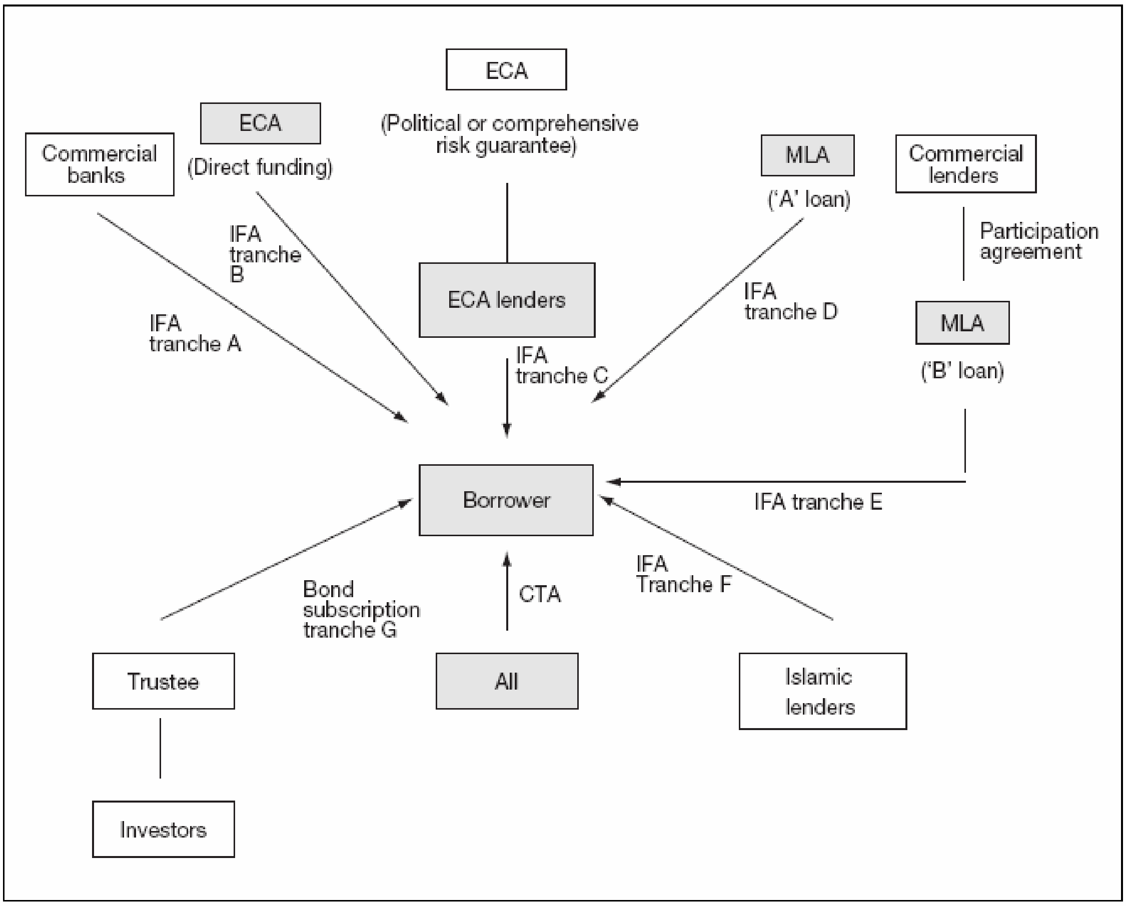

Figure 14: Possible financing sources for large LNG projects (source: [15]).

7.3 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.

7.4 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.

8 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 with 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.

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