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An annual electricity market simulator: model description and application in a pan-European framework

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1 CHAPTER ONE: THE MEDIUM TERM SIMULATOR MTSIM

1.1 GENERAL FEATURES

This chapter has the intent to provide a brief classification of the main simulation techniques applied in the electricity market. A schematic classification of electricity market simulator is reported in Figure 1.

Depending on the time horizon, an electricity market simulator has different variables and objectives.

The horizon impacts on the level of detail that is represented in the reference mathematical model.

Short term simulators are characterized by a high modeling detail level, while long term simulators have a low level of detail but allow modeling the evolution of the generation park.

Medium term simulators, like MTSIM, are characterized by a fix generation park and a medium detail level, typically created in order to perform scenario analysis.

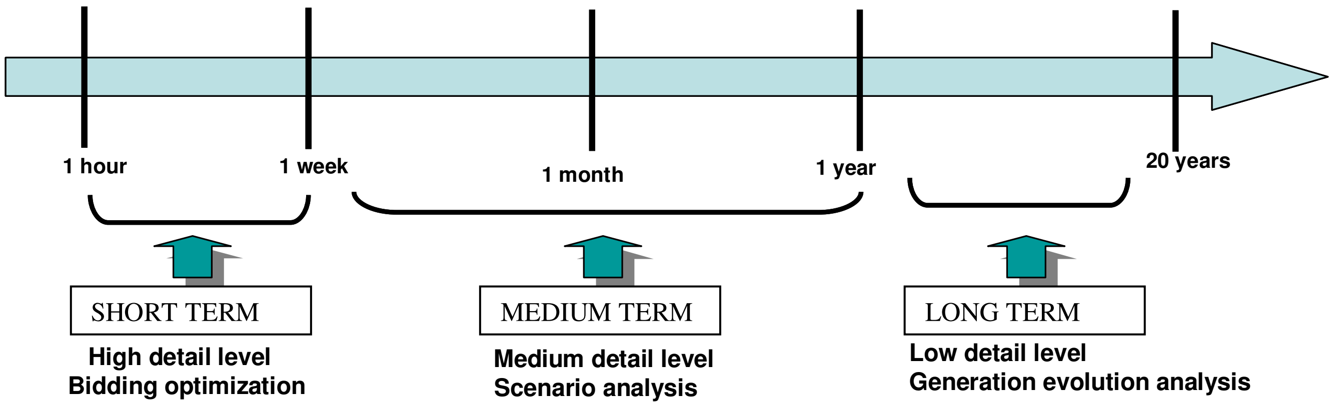

Figure 1 - Classification of electricity market simulators

The horizon affects the scope for which simulators are built, as shown in Figure 2.

Due to the high detail level, short term simulators are used for producers in order to analyze and optimize bid strategies on a given hour.

Medium and long term simulators are typically used by research centers to perform scenario analysis and by regulatory authorities to analyze the impact of new actions.

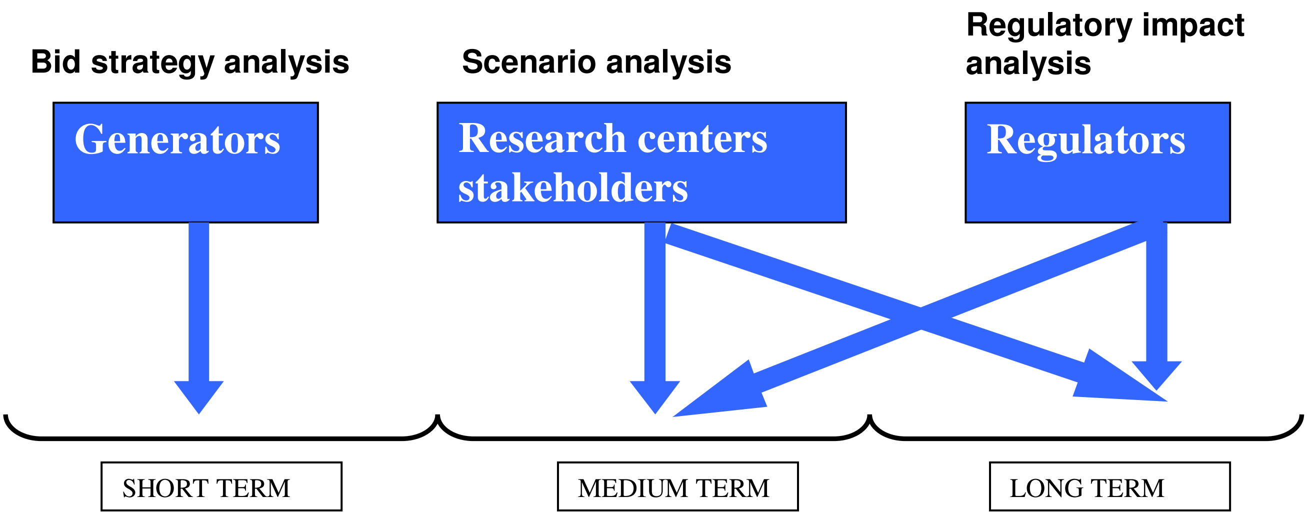

Figure 2 - Use of electricity market simulators

In particular, medium term simulator are applied in market monitoring, consisting in asses speculative behavior that decrease the efficiency and that shift the solution from the perfect competition optimum.

Typically the market monitoring requires the calculus of market indexes. There are four different approaches:

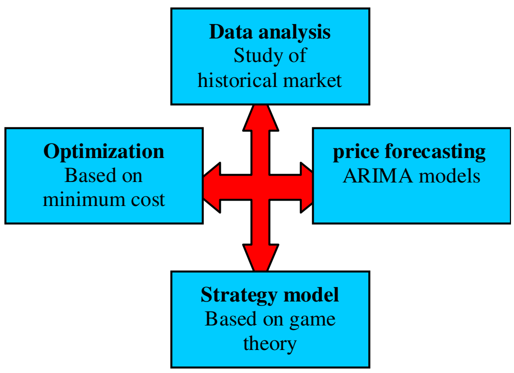

Figure 3 – approach possibilities

Models based on historical data (mainly regression models) have numerous applications, like prediction (including forecasting of time-series data), inference, hypothesis testing, and modeling of causal relationships; nevertheless these kind of models have the weak point that are not able to describe changes due to new scenario hypotheses. Models based on cost minimization are useful in a centralized market structure, but lose importance in a decentralized market model.

The game theory approach (see [11]), conceptually more adherent than classic optimization approaches to the real competition mechanisms, currently shows important criticizes that put a serious limitation to its usage to describe real-sized markets (see [12]). Real market players don't strive to maximize their surplus. This is even more evident in the case of big national incumbents, able to raise market prices at will but constrained by internal and policy constraints limiting their exercise of market power. A second aspect is the non-convexity of game theory models describing multi-zonal markets, that makes these models non suitable to perform sensitivity analyses.

Thus classic approaches may prove more reliable than game theory models. They must, however, be reformulated in the sense of price minimization (instead of cost minimization).

The main classification of the approaches for market monitoring is: classic optimization models (deriving from minimum cost approaches) and game theory based model.

The main difference is that, in the classic approach, created in the context of old vertically integrated company, decisions are centralized into a single entity that establish the dispatching of the generation park on the basis of a operational costs minimization.

This approach breaks down with the paradigm of competitive electricity markets, in which the decision is no longer centralized but managed by independent organizations that are coordinated into a market structure.

1.2 TECHNICAL SPECIFICATIONS

Electricity markets are cleared hourly, determining, on the basis of sale and purchase offers, the amount of energy that each power plant has to produce and the relative price of remuneration.

MTSIM (Medium Term SIMulator) 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[1]) 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);
- 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 modeled endogenously: hourly generation profiles have to be provided as input to the simulator.

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[1] 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.

MTSIM has been developed and used to simulate the optimal behavior of the modeled European power system (see chapter 3 and 4), having as objective function the cost (fuel and CO2 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 scenario.

Some features of the simulators are:

- NETWORK MODEL: in order to guaranty the feasibility of the solution, hourly network constraints are taken into account, in the form of minimum and maximum power that can pass on any interconnection. The network can be radial or meshed.
- DEMAND: electricity demand (MWh) is expressed as a zonal inelastic input. This demand do not take into account pumping generation (that are modeled into the model as dispatchable power plants), but incorporates network losses. Moreover, for each zone, it is also possible to define a minimum level of spinning reserve, express as a percentage of the load.
- THERMAL POWER PLANTS: a set of parameters is defined for each termal power plant in order to specify:
    - The GenCo;
    - The zone in which is placed;
    - Minimum and maximum power;
    - The fuel mix (up to two): for each fuel and plant a linearized curve consumption has been define;
    - The rate of unavailability (accidental or planned events), given as monthly percentage.

  Because of outage events (planned or accidental), a generation unit can be not available for a given number of hours. This unavailability has been taken into account decreasing the maximum power of each thermal power plant. Each group is associated with constraints on the flexibility of the plant operation (i.e. the maximum frequency of start up and turn off). It is also possible to specify data variable during the simulation. In particular, there is the possibility of considering changes in the technical minimum; this can allow to model bilateral contracts, which correspond to zero value on offer.

  The supply of each thermal power plant consists of:

    - fuel variable cost;
    - bid-up depending on offering strategy;
    - other variable costs (environmental costs, opportunity costs).

- CONSTRAINTS: Constraints on the operation of thermal power plants may be imposed both on a single plant both on a set of thermal power plants. In particular, there are two kind of constraints:
  - "Simple" constraints: specific plants can be defined as "must-run", so that they can operate only at a predefined power on one or more time frame.
  - "Integral" constraints: there are three integral constraints, i.e. the production, the fuel consumption and/or emissions of one or more power plant can be limited.
- ENVIRONMENTAL CONSTRAINTS: CO_2 emission and other pollutant constraints are taken into account. As regards the production of CO_2 for each plant, an emissivity factor depending on the type of fuel used is defined. Each thermal power plant has a maximum quantity of producible CO_2 over a given period (optional integral constraint).

  If the total CO_2 production exceeds the quota admitted for the system, producers can buy necessary quotas in the emission markets (ET or CDM) at a given price, while excess allowances can be sold to other producers. Prices on emission markets are input for the model.
- HYDRO POWER PLANTS: The hydroelectric system is represented by a linear model:
  - An equivalent for each valley regarding basin/reservoir;
  - Single representation for run of rivers power plants.

The main pumping power plants are modeled separately; basin, reservoir and pumping power plants are modeled taking into account:

- Minimum power (negative in case of pumping);
- Maximum power;
- Programmed unavailability;
- Initial/final volume constraints;
- Efficiency (in case of pumping);
- Hourly spilling.

BILATERAL CONTRACTS: Bilateral contracts are handled by constraining the operation of thermoelectric power plants (constraint "must-run").

1.3 SIMULATOR STRUCTURE

The MTSIM simulator read input data from an Excel file. Hydro-thermal dispatching is calculated using Matlab LINPROG routine or the homonymous routine of Tomlab package [52].

The hydro-thermal unit commitment is determined by a dispatching with zero technical minimum and using heuristic techniques. Results are written in an Excel file. MTSIM Matlab code reflects the mathematical formulation of the problem. The MATLAB Software makes the code more streamlined, modern and readable with a view to future changes. In fact, the widespread use of this language is mainly due to its ease of use.

When programming MTSIM, the overwhelming size of the system requires numerical analysis: it was necessary to define the problem in a sparse-form: the only coefficient matrix exceeded the memory addressable by a 32-bit system.

Initially the solver for large systems of LINPROG routine (included in the Matlab optimization toolbox) has been used. This solver accepts the description in the sparse-form of the constraint matrix.

Afterwards this implementation has been proved unsuitable: the management of the memory is not fully optimized, leading to *memory fault* problems.

Therefore, the Tomlab commercial toolbox has been chosen: this toolbox, really performing, implements the solver CPLEX provided by ILOG. Sparse matrixes are big dimension matrix with a predominance of zero elements. Matrixes with at least 50 % of zero elements can be considered sparse.

In MATLAB it is possible to define matrixes in a sparse-form (Figure 4), defining only the nonzero elements and the information needed to locate the position of these elements.

Avoiding operations on zero elements reduces the number of operations required and speeds up the computation.

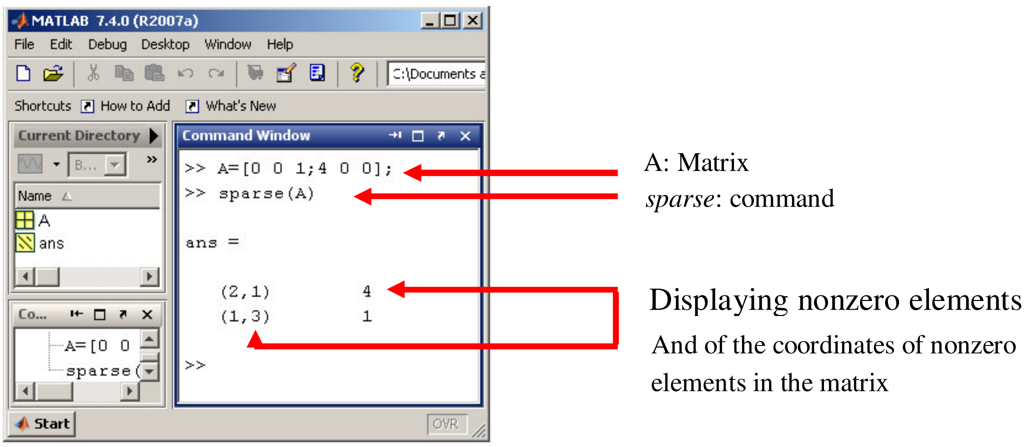

Figure 4 - “sparse” command

In order to reduce the computation time (otherwise unacceptable with a PC corresponding to the average of the current state of the art), it was decided to introduce the option of reducing the time dimension (otherwise equal to the number of hours in a year).

It is possible to group the hours building a mobile band of confidence (e.g. 10%) around the zonal load mean: gradually, hours are aggregated into a single hour until they come out of that band[2].

In order to avoid side effects of demand "smoothing", which do not allow the properly assessment of the power generation necessary to meet the peak day load, the time corresponding to the peak loads are considered individually (they are never considered in the aggregation).

The same reasoning is done for the minimum daily load, which is significantly affected by the unit commitment.

Finally, the first and the last hours of the integral and must-run constraints (if there are) are never accounted in the aggregation.

An example of this mechanism is shown in Figure 5.

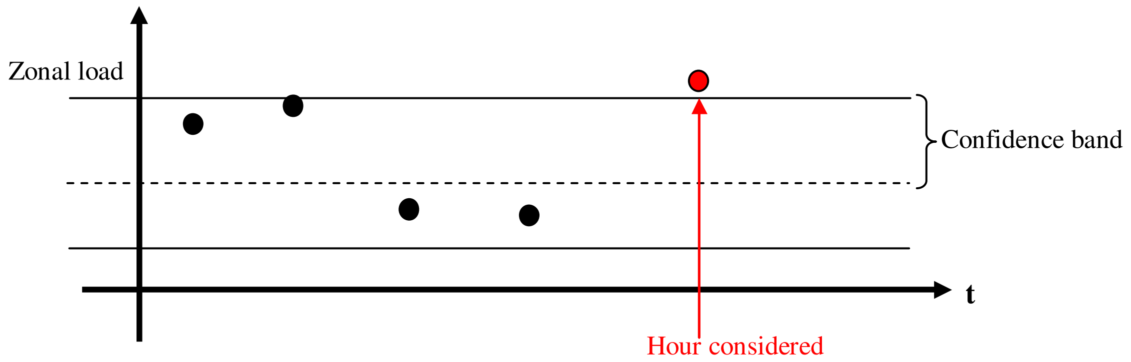

Figure 5 – hourly compression

A scheme of the structure of MTSIM simulator is reported in Figure 6.

[2] The zonal load mean is considered mobile, equal to the average in the hours-group equivalent to the one currently tested.

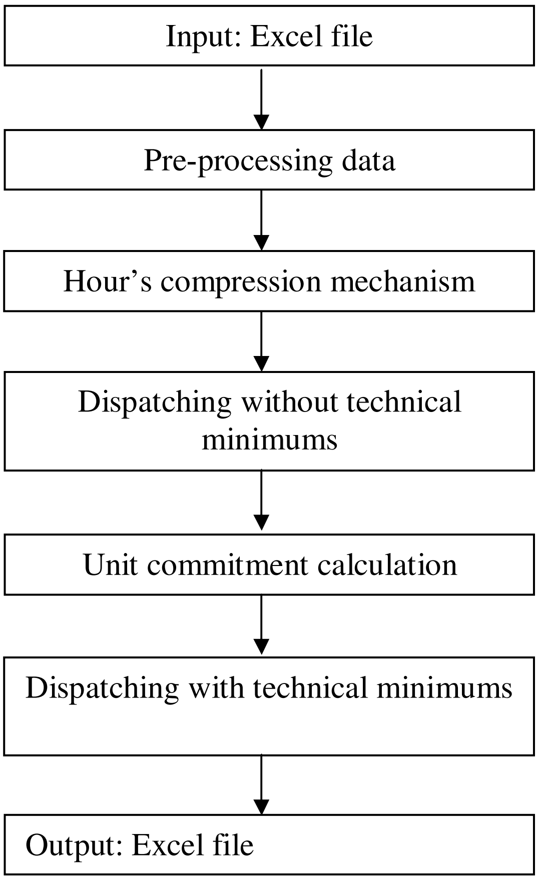

Figure 6 - MTSIM Structure

In the following the description of each block:

1. input – Excel file: this module reads the Excel file containing the input data (characteristics of the generators, hourly zonal load, fuel costs, network limits between areas, flexibility of thermal power plants, etc...). The information is re-elaborated in an internal object structure for an efficient use.
2. Pre-processing data: this module handles the matrix operations before calling the solver. These calculations are useful, for example, to take into account the maintenance plan of thermal power plants, as well as the unavailability due to accidents. Another example is the computation of the dispatchable load, obtained by eliminating from the total load the power generated that does not participate in the market (e.g. CIP6).
3. Hour’s compression mechanism: this module calculates the hour compression as described above.
4. Dispatching without technical minimums: in this part an initial calculation of the dispatching is performed, considering all the hydro thermal units available without technical minimum
5. Unit commitment calculation: in this section the program determines the power plants state.

6. Dispatching with technical minimums: here the market clearing is calculated taking into account the technical minimums and the results of the unit commitment solution (i.e. which groups are turned on or switch off).
7. Output – excel file: results are re-elaborated and written in Excel files.

1.4 MATHEMATICAL MODEL OF HYDRO-THERMAL DISPATCHING IN MTSIM

The objective of the simulation is the hourly resolution of the electricity market through an energy price minimization.

This objective can be formulated as follow:

$$\min\left\{\sum_t\left[\sum_g c_{\mathrm{gt}}\ p_{gt} + \sum_z VOLL \cdot ENP_{zt} + \sum_z VOEE \cdot EIE_{zt}\right]\Delta T_t + c_{ET}\ GCBuyET + c_{CDM}\ GCBuyCDM\right\}$$

With:

p_{gt}	Power of thermal plant g at time t
ΔT_t	Time interval
$VOLL$	Value Of Lost Load
$VOEE$	Value Of Exceeding Energy
ENP_{zt}	Energy Not Provided in zone z at time t
EIE_{zt}	Energy In Excess in zone z at time t
c_{ET}	Emissions Trading costs
c_{CDM}	Clean Development Mechanism costs
$GCBuyET$	Quantity of ET quote
$GCBuyCDM$	Quantity of CDM credits

The system is characterized by technical constraints that must be met to maintain solution feasibility.

In the following are reported the system constraints that have been taken into account.

1. <u>Power of thermal plants</u>

In each period t the power generate p_{gt} by each thermal plants must respect technical constraints:

$$p_{gtm}\, s_{gt} \leq p_{gt} \leq p_{gtM}\, s_{gt}$$

With:

p_{gm} , p_{gM} minimum and maximum power

s_{gt} state of the plants (0= off, 1=on)

2. Must-run on thermal plants

The power generated by a thermal plant must be equal to a predefined value p^*_{gt} or can't be below it in a defined time interval:

$$p_{gt} = p^*_{gt} \qquad \forall g \in \Gamma_1 \ \forall t \in T_1^* \quad p_{gtm} \leq p^*_{gt} \leq p_{gtM}$$

$$p_{gt} \geq p^*_{gt} \qquad \forall g \in \Gamma_2 \ \forall t \in T_2^*$$

Where:

p^*_{gt} *must-run* power of plant g at time t

Γ_2 set of thermal plants

3. Thermal production

The production $E_{\Gamma T*}$ *of all thermal power plants in on state must respect techncal constraints on a given period:*

$$E_{m\Gamma T*} \leq \sum_{t \in T^*} \sum_{g \in \Gamma} k \ p_{gt} \ \Delta T_t \leq E_{M\Gamma T*}$$

With:

$E_{m\Gamma T*}, E_{M\Gamma T*}$ *Minimum/maximum energy*

k *power multiplier.*

4. Fuel consumption

Fuel consumption $W_{\Gamma T*}$ of all thermal power plants on a given period must respect technical constraints:

$$W_{m\Gamma T*} \leq \sum_{t \in T^*} \sum_{g \in \Gamma} \pi_{\mathrm{gtf}} \left(B_{1gtf} \, p_{gt} + B_{0gtf} \, s_{gt}\right) \Delta T_t \leq W_{M\Gamma T*}$$

With:

$W_{m\Gamma T*}, W_{M\Gamma T*}$ *Minimum/maximum fuel consumption*

B_{0gtf} Fuel consumption curve of thermal power plant g at time t (fix term).

5. <u>CO_2 Emission</u>

Maximum CO_2 quantity that can be produced by one or more thermal power plants belonging to the same GencCo (Generation Company) shall meet the following constraint:

$$\sum_{t\in T^*}\sum_{g\in\Gamma}\sum_{\Phi i(g)}\pi_{t\Phi i(g)}\, f_{CO2\ \Phi i(g)}\left(B_{1\,gt\Phi i}\ p_{gt}+B_{0\,gt\Phi i}\ s_{gt}\right)\cdot\Delta T_t\le M_t$$

With:

M maximum quantity of CO_2

6. <u>Power of hydro plants</u>

In each period t the power generated p_{ht} (q_{ht} for pumping plants) by each hydro ppt h must respect technical constraints:

$$0 < p_{ht} < P_{Mht} \qquad 0 < q_{ht} < Q_{Mht}$$

With:

p_{ht} power produced by hydro power plant h at time t

P_{Mht} maximum power of hydro power plants h at time t

q_{ht} power produced by pumping plant h at time t

Q_{Mht} maximum power of pumping power plants h at time t

7. <u>Reservoir volume</u>

In each period hydro reservoir volume V_{ht} must meet technical constraints:

$$V_{mht}\le v_{h0}+\sum_{\tau<t}\left[\left(n_{h\tau}-w_{h\tau}-\frac{p_{h\tau}-\eta_h q_{h\tau}}{\lambda_h}\right)\Delta T_t\right]\le V_{Mht}$$

With:

V_{mht}, V_{Mht} Minimum/maximum volume of the reservoir h at time t

v_{h0} Reservoir initial volume

$n_{h\tau}$ Natural inflow in the reservoir h in the period τ

$w_{h\tau}$ Spill out of the reservoir h in the period τ

η_h Pumping efficiency

λ_h Energy coefficient

8. Transit between nodes

The transit I_{lt} between nodes on a give period must comply with technical constraints:

$$I_{mlt} \leq \sum_{z}\left(\sigma_{lz}\left(\sum_{g\in z} p_{gt} + \sum_{h\in z}(p_{ht} - q_{ht}) - C_{zt}(1+r_{st}) + ENP_{zt} - EIE_{zt}\right)\right) \leq I_{Mlt}$$

(r_{st} only in UC phase)

With:

I_{mlt}, I_{Mlt}	Maximum/minimum transit at time *t*
σ_{lz}	PTDF coefficient in zone *z*
C_{zt}	Hourly load in zone *z* at time *t*
r_{st}	Reserve

9. Balance of the system.

$$\sum_{g} p_{gt} + \sum_{h}(p_{ht} - q_{ht}) = \sum_{z}(C_{zt}(1+r_{st})) - \sum_{z} ENP_{zt} + \sum_{z} EIE_{zt}$$

10. Energy not Provided

$$ENP_{zt} \geq 0$$

11. Energy in excess

$$EIE_{zt} \geq 0$$

12. CO_2 emission

The CO_2 quantity that can be produced by all generators must meet the following constraint:

$$\sum_{t}\left(\sum_{g}\sum_{\Phi i(g)} \pi_{t\Phi i(g)}\, f_{CO2\,\Phi i(g)}\left(B_{1gt\Phi i}\, p_{gt} + B_{0gt\Phi i}\, s_{gt}\right)\right)\cdot \Delta T_{t} \leq \overline{PCO2}_{system} + \ldots$$
$$+ GCBuyET + GCBuyCDM$$

$$GCBuyET_{m} \leq GCBuyET \leq GCBuyET_{M} \qquad GCBuyCDM_{m} \leq GCBuyCDM \leq GCBuyCDM_{M}$$

$$GCBuyET_{m} \leq 0 \quad GCBuyCDM_{m} \leq 0$$

With:

$PCO2_{system}$	Maximum quota admitted for the system

1.4.1 INEQUALITY CONSTRAINTS REFORMULATION AS EQUALITIES CONSTRAINTS WITH UPPER AND LOWER BOUND.

The constraints that have been defined until now are both equality and inequality constraint.

In order to obtain maximum performances from the tool that will calculate the constrained minimum, it has been chosen to use only equality constraints.

In the following it is described how inequality constraints have been reformulated into equality constraints.

1. Production of thermal power plants

$$E_{\Gamma T*} = \sum_{t \in T^*} \sum_{g \in \Gamma} k \; p_{gt} \; \Delta T_t$$

2. Fuel consumption

$$W_{\Gamma T*} = \sum_{t \in T^*} \sum_{g \in \Gamma} \pi_{\text{gtf}} \left(B_{1gtf} \, p_{gt} + B_{0gtf} \, s_{gt} \right) \Delta T_t$$

3. CO_2 emissions

$$Emiss_{CO2} = M_t - \sum_{t \in T^*} \sum_{g \in \Gamma} \sum_{\Phi \text{i}(\text{g})} \pi_{\text{t}\Phi i(g)} \, f_{CO2 \; \Phi i(\text{g})} \left(B_{1\,gt\Phi i} \; p_{gt} + B_{0\,gt\Phi i} \; s_{gt} \right) \cdot \Delta T_t$$

4. reservoir volume

$$V_{ht} = V_{h\,t-1} + \left(n_{ht} - w_{ht} - \frac{p_{ht} - \eta_h q_{ht}}{\lambda_h} \right) \Delta T_t$$

$$V_{h0} = \overline{v}_{h0}$$

5. Transit between nodes

$$I_{lt} = \sum_z \left(\sigma_{lz} \left(\sum_{g \in z} p_{gt} + \sum_{h \in z} \left(p_{ht} - q_{ht} \right) - C_{zt} \left(1 + r_{st} \right) + ENP_{zt} - EIE_{zt} \right) \right)$$

(r_{st} only in Unit Commitment phase)

6. CO_2 margin

$$MargCO2 = \overline{PCO2}_{Italy} + GCBuyET + GCBuyCDM - \sum_t \left[\sum_g \sum_{\Phi \text{i}(\text{g})} \pi_{\text{t}\Phi i(g)} \, f_{CO2 \; \Phi i(\text{g})} \left(B_{1\,gt\Phi i} \; p_{gt} + B_{0\,gt\Phi i} \; s_{gt} \right) \right] \Delta T_t$$

Upper and lower bounds

1. Power of thermal power plants

$p_{gtm}\, s_{gt} \leq p_{gt} \leq p_{gtM}\, s_{gt}$

2. Must-run on thermal power plants

$p_{gt} = p^*_{gt} \quad \forall g \in \Gamma_1 \;\; \forall t \in T_1^* \quad p_{gtm} \leq p^*_{gt} \leq p_{gtM}$

$p_{gt} \geq p^*_{gt} \quad \forall g \in \Gamma_2 \;\; \forall t \in T_2^*$

3. Production of thermal power plants

$E_{m\Gamma T*} \leq E_{\Gamma T*} \leq E_{M\Gamma T*}$

4. Fuel consumption

$W_{m\Gamma T*} \leq W_{\Gamma T*} \leq W_{M\Gamma T*}$

5. CO_2 emissions

$Emiss_{CO2} \geq 0$

6. power of hydro plants

$0 < p_{ht} < P_{Mht} \qquad 0 < q_{ht} < Q_{Mht}$

7. reservoir volume

$V_{mht} \leq V_{ht} \leq V_{Mht}$

7. Transit between nodes

$I_{mlt} \leq I_{lt} \leq I_{Mlt}$

8. Energy not provided

$ENP_{zt} \geq 0$

9. Energy in excess

$EIE_{zt} \geq 0$

10. CO_2 emissions

$MargCO2 \geq 0$

$GCBuyET_m \leq GCBuyET \leq GCBuyET_M \qquad (GCBuyET_m \leq 0)$

$GCBuyCDM_m \leq GCBuyCDM \leq GCBuyCDM_M \quad (GCBuyCDM_m \leq 0)$

1.4.2 EQUATIONS AND VARIABLES ORDER

Given the huge size of the matrixes, for which it was necessary to define the problem in a sparse form, it is very important to achieve a system of equations and variables that will facilitate the numerical treatment by the solver.

It is true that the majority of the solvers implement, in a pre-processing phase, a row and column permutation of the matrix of the coefficients in order to obtain the best problem structure, but the a priori knowledge of the problem allows the identification of the best structure of the problem, facilitating the task of the pre-processor.

It is commonly known that a block-diagonal structure is the best one that eases the numerical treatment of large systems.

Therefore, the matrix is structured as following:

- Variables (i.e. columns) for growing times
- Equations without integral constraints and then equation with integral constraints.

The method used in order to obtain the solution is the "linprog" function of Matlab.

X=LINPROG(f,A,b) attempts to solve the linear programming problem:

$$\begin{aligned}
&\min_x \; f' \cdot x \\
&s.t. \quad Aeq \cdot x = Beq \\
&\qquad\;\; A \cdot x \leq b \\
&\qquad\;\; Lb \leq x \leq Ub
\end{aligned}$$

As described previously, in order to obtain maximum performances from the function that calculate the constrained minimum, it has been chosen to use only equality constraints. Thus A and b are respectively a null matrix and a null vector.

The matrixes for the hydro-thermal dispatching are reported in

APPENDIX I.

1.4.3 MTSIM in planning modality

The mathematical model of MTSIM can be executed in “planning” modality: in this modality the program takes into account possible network expansions.

In this case, for each interconnection between two zones, in input it is necessary to know:

- An annualized average unit cost [€/MW] associated with the installation of additional interconnection capacity [X_{inst}];
- The maximum potential expansion of the connector [MW]. This expansion is supposed to be bilateral and symmetric in addition to the existing capacity in both flow directions

The installation cost K_{inst} multiplied by the real installed capacity provides, in the objective function, the total annual investment in new capacity.

MTSIM calculates the best trade-off between the reduction of operating costs (that the installation of new capacity may involve, i.e. bottlenecks reduction and/or more efficient generation dispatching) and the costs of installing new capacity in the system. The result is an indicator of the most critical backbone that might deserve an expansion.

1.4.3.1 Mathematical model modification

The mathematical model, when MTSIM operates in planning modality, changes from the “traditional case” as shown below.

The objective function takes into accounts not only operational costs, but also any costs of network expansion.

$$\begin{cases} \min C_{TOT} = \sum_t operational\cos ts_t + \sum_t K_{inst_i} X_i \\ \dots \\ I_{\min_i} - X_i \le I_i \le I_{\max_i} + X_i \end{cases}$$

Where:

- C_{TOT}: Total cost [€];
- K_{inst_i} : annualized average unit cost of transit expansion [€/MW];
- I_i : real transit on the line [MW];
- X_i : expansion of the interconnection capacity [MW]; this value must be minor or equal to the value defined for X_{imax};

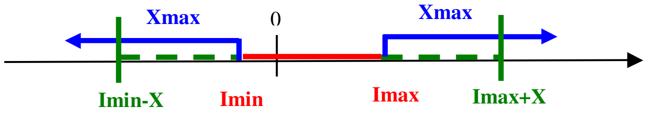

Figure 7 - transit expansion in planning modality

X_i Variables:

- Are as many as the interconnection lines;
- Add to problem variables;
- Are placed at the end of the variables list;
- Have lower bound equal to zero;
- Have upper bound equal to the maximum installed capacity (X_{imax}).

The upper/lower bound of the transit flow are removed (put a +/-∞) and replaced by a set of inequalities, that are reformulated into a pair of inequalities:

$$I_i - X_i \leq I_{\max_i}$$
$$-I_i - X_i \leq -I_{\min_i}$$

Therefore, two matrices A and b (not present in non-planning modality) are added, according to the structure required by the *linprog* routine in MATLAB:

$$\min f \cdot x \qquad s.t. \qquad \begin{aligned} A \cdot x &\leq b \\ A_{eq} \cdot x &= b_{eq} \\ lb \leq x &\leq ub \end{aligned}$$

Thus, in the case of planning modality, expansion costs per each line and the maximum capacity increasing (a single valued for both directions) must be provided as an input of the model.
As output, it will be provided the real additional capacity installed by MTSIM.

2 SECURE - GAS SHORTAGE

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, the objective of this work is 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 MTSIM simulator, 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 CO2 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 analysis will be reported according to six-step methodology (the same defined in the SECURE-EU project):

- Step 1: threat identification and assessment;
- Step 2: impact assessment;
- Step 3: assessment of EU vulnerability to energy risks;
- Step 4: cost assessment;
- Step 5: remedies assessment;
- Step 6: how remedies should be financed / paid for.

3.1 STEP 1: threat identification and assessment

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

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

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

As for the assessment of the probability of occurrence of this threat, it must be noticed that it is not as 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 ongoing3.

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

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

3.2 STEP 2: impact assessment

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

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 0, 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.

Supply

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 reported4.

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 8), that is **0.11 bcm/month**.

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

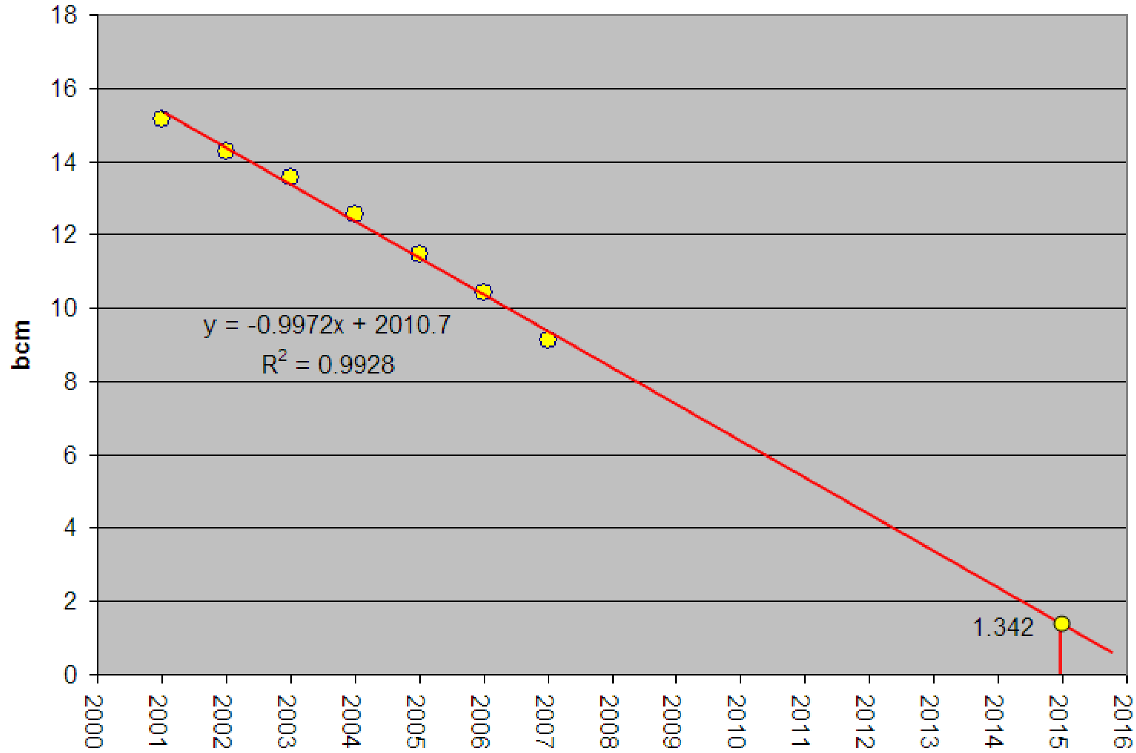

Figure 8: Extrapolation to 2015 of the Italian national gas production.

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[5].

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[6] 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 and since the final investment decision has not been taken yet, we will not take it into account in the present analysis.

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[5] Source: http://www.igi-poseidon.com/english/project.asp.

[6] 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[7]	Maximum effective monthly capacity[8]
Tarvisio (TAG)	40.2[9]	36.7	3.06
Passo Gries (TENP / TRANSITGAS)	23.4	21.3	1.78
Gela (GREENSTREAM)	11[10]	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).

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[11], 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 are reported. The maximum effective monthly import capacity is around **1.21 bcm/month**.

[7] Calculated assuming 8000 hours/year at maximum theoretical capacity, taking into account maintenance outages.
[8] Corresponding to the maximum effective annual capacity divided by 12.
[9] From end 2009, source ENI.
[10] From 2011, source ENI.
[11] 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[12]	Maximum effective monthly capacity[13]
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).

Gas storage

In Italy gas storage capacity for the modulation service is currently about 8.72 bcm. There are several projects[14] 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[15] and EDISON[16], the two companies operating the storage facilities. Such optimal profiles are reported in Table 4.

[12] Calculated assuming 95% of the maximum theoretical capacity, taking into account logistic constraints.
[13] Corresponding to the maximum effective annual capacity divided by 12.
[14] See Authority for Electric Energy and Gas (AEEG) http://www.autorita.energia.it/it/dati/infragas2.htm.
[15] 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.
[16] See: http://www.edisonstoccaggio.it/pages/page.aspx?item_id=162.

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).

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.

Demand

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**[17].

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.

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).

[17] Source: Ministry of Economic Development.

To this aim we used the time series of the *degree days*[18] 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;
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).

[18] *Degree day = max (0 ; 18 – (Tmin + Tmax) / 2)*, where *Tmin* and *Tmax* are the minimum and maximum daily temperatures.

Network consumptions and losses

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

Gas available for power generation

The balance of supply and demand calculated in paragraphs 0 and 0 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).

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.

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.[19] 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**.

[19] 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[20]	0.70[20]
New storage	25[21]	0.14[22]	0.14[22]
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.

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 0). 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.

[20] 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.
[21] Purported withdrawal rate according to the EBRD database.
[22] 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.

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**.

3.3 STEP 3: assessment of EU vulnerability to energy risks

In order to assess the vulnerability of the European power system to a gas supply shortage, it is interesting to take into account the share of gas-fired production over the whole electricity production in each country. In the following

Table 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 0).
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] and [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 0 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).

3.4 STEP 4: cost assessment

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

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

The assessment has been carried out by developing and running a model of the European power system, based on the MTSIM simulator, developed by RSE.

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

The model of the European power system

Representation of the transmission network

The European AC transmission network has been modeled with an equivalent representation (see Figure 9) 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 9 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

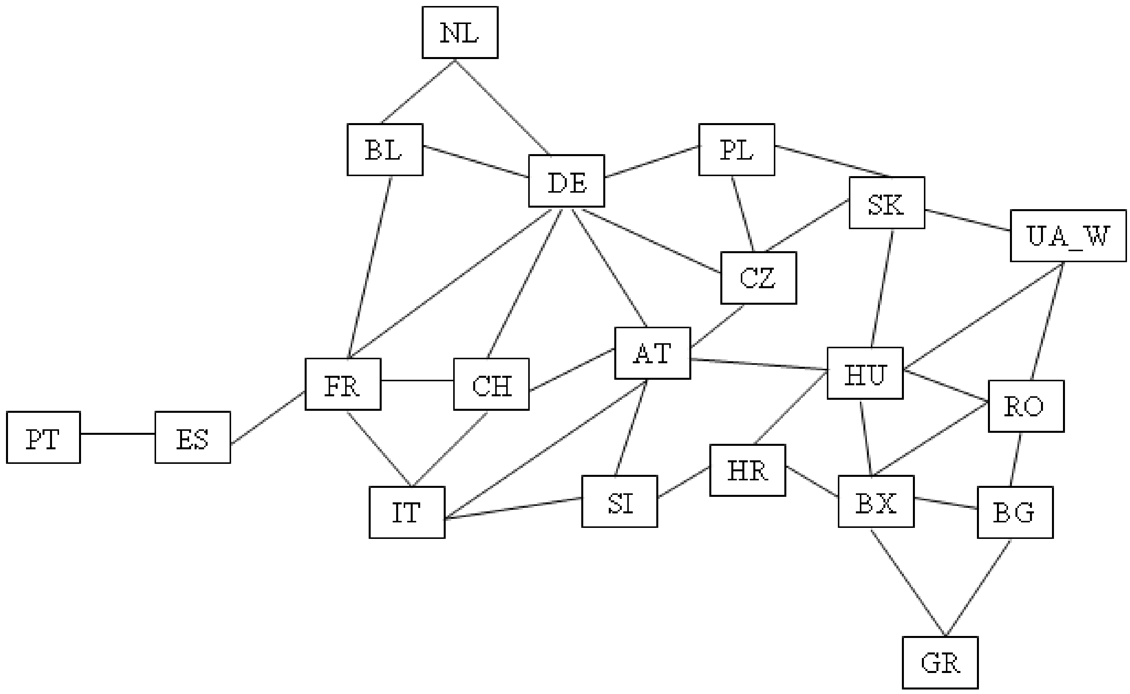

Figure 9: Equivalent representation of the European AC transmission network.

The PTDF[23] (*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 in [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[24].

[23] 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.
[24] This is the case, for example, of the interconnection Slovenia ⇨ Italy.

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.

In the following Table 11, summer[25] and winter[26] 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.

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

In Figure 10, 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
- DK_E: Denmark East
- SE: Sweden
- MA: Morocco
- GB: Great Britain
- TR: Turkey
- MD: Moldova
- BY: Belarus
- UA: Rest of Ukraine

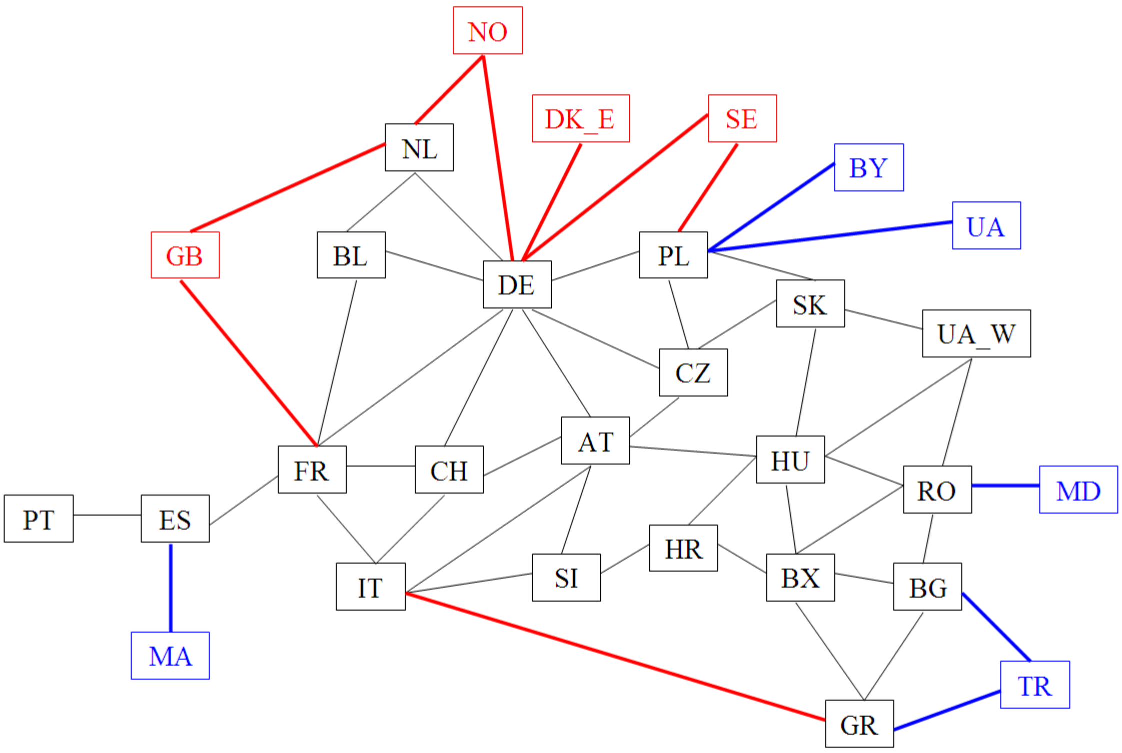

Figure 10: Cross-border DC interconnections (in red) and AC interconnections with other power systems (in blue).

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.

Representation of the power generation system

As shown in Figure 9, 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 RSE.

Fossil fuelled thermal power plants

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[27] 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.

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

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.

Net generation capacity

- <u>*Total generation capacity*</u>

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.

- <u>*CHP generation capacity*</u>

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.

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.

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.

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.

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.

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.

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 11).

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 12).

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 13).

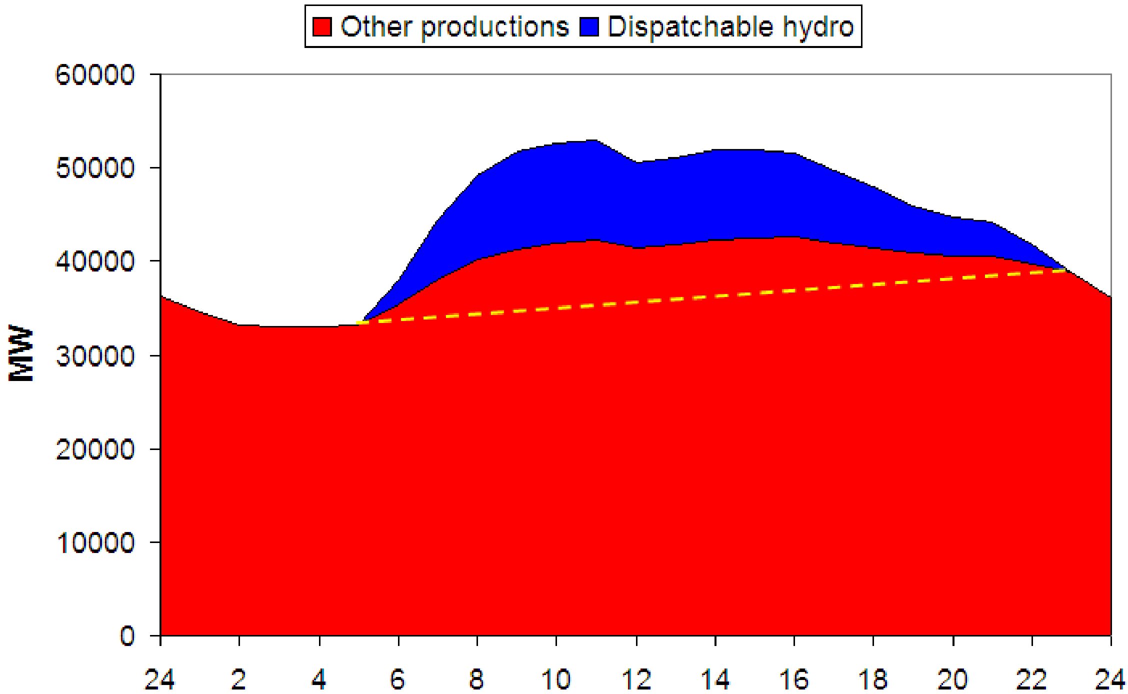

Figure 11: Hourly profile of dispatchable hydro – first case.

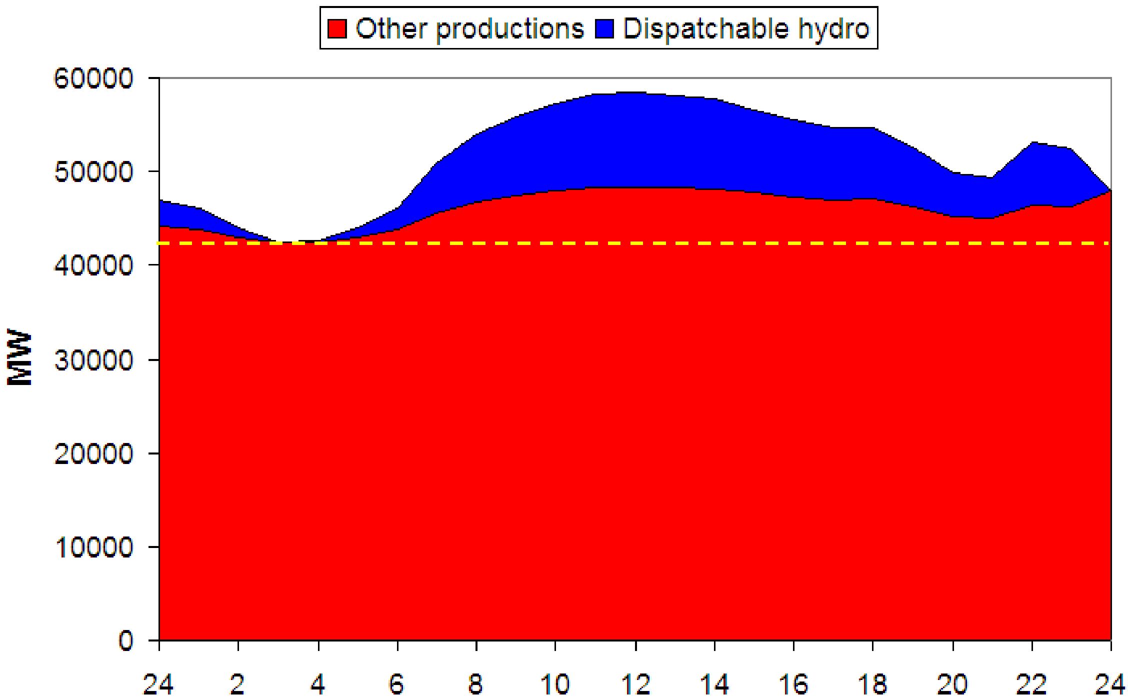

Figure 12: Hourly profile of dispatchable hydro – second case.

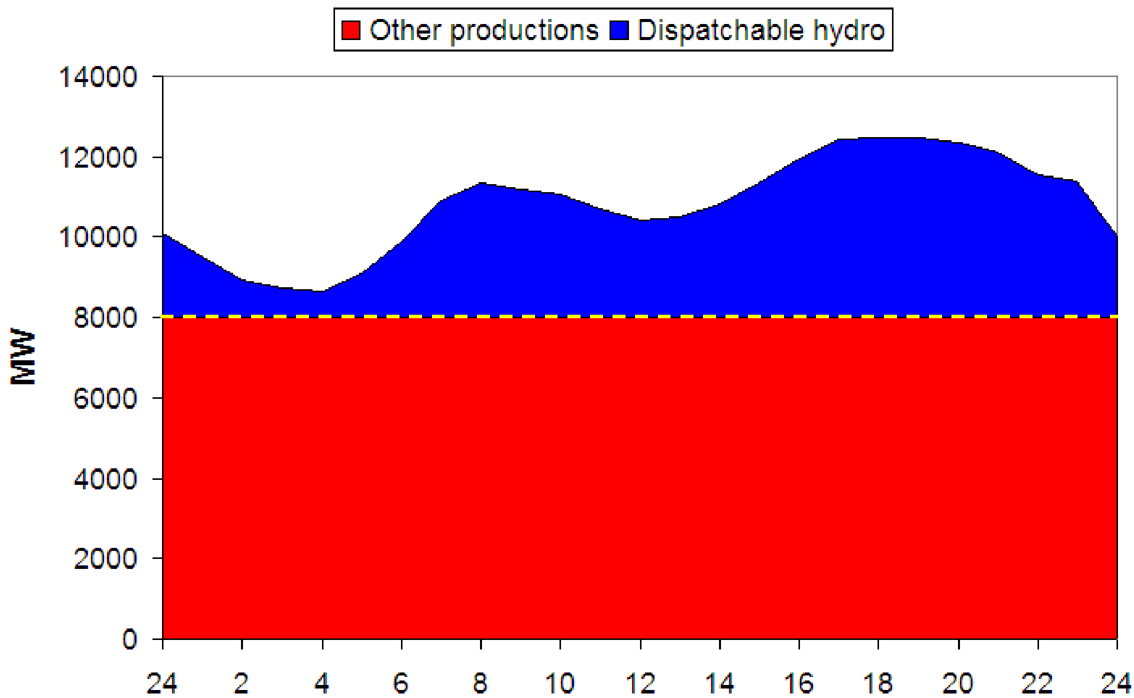

Figure 13: Hourly profile of dispatchable hydro – third case.

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.

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.

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.

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 **Errore. L'origine riferimento non è stata trovata.**.

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 14 production profiles of a 1 kWp plant located in Rome (Italy) and installed with an optimal inclination of 34° are shown.

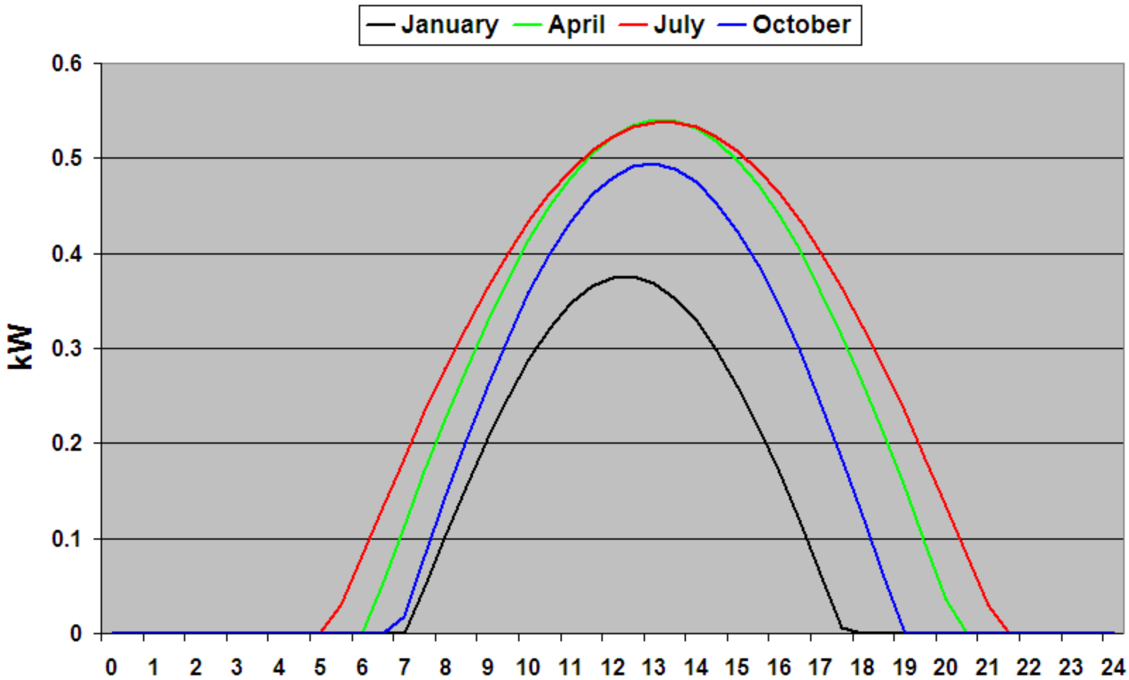

Figure 14: Example of daily production profiles of a 1 kWp photovoltaic solar power plant installed in Rome (Italy) with an optimal inclination of 34°.

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[28]. 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.

[28] 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.

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.

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.

CO_2 emissions value

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

Electrical load

The annual values of the 2015 electrical load (final consumptions plus network losses; pumped storage consumption not included: see paragraph 0) 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**	**Δ%**
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.

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.

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).

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[29], 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.

[29] **92 Mcm** of strategic gas storage are necessary in December to keep all CHP gas-fired power plants in operation.

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.

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.

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 15 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 16.

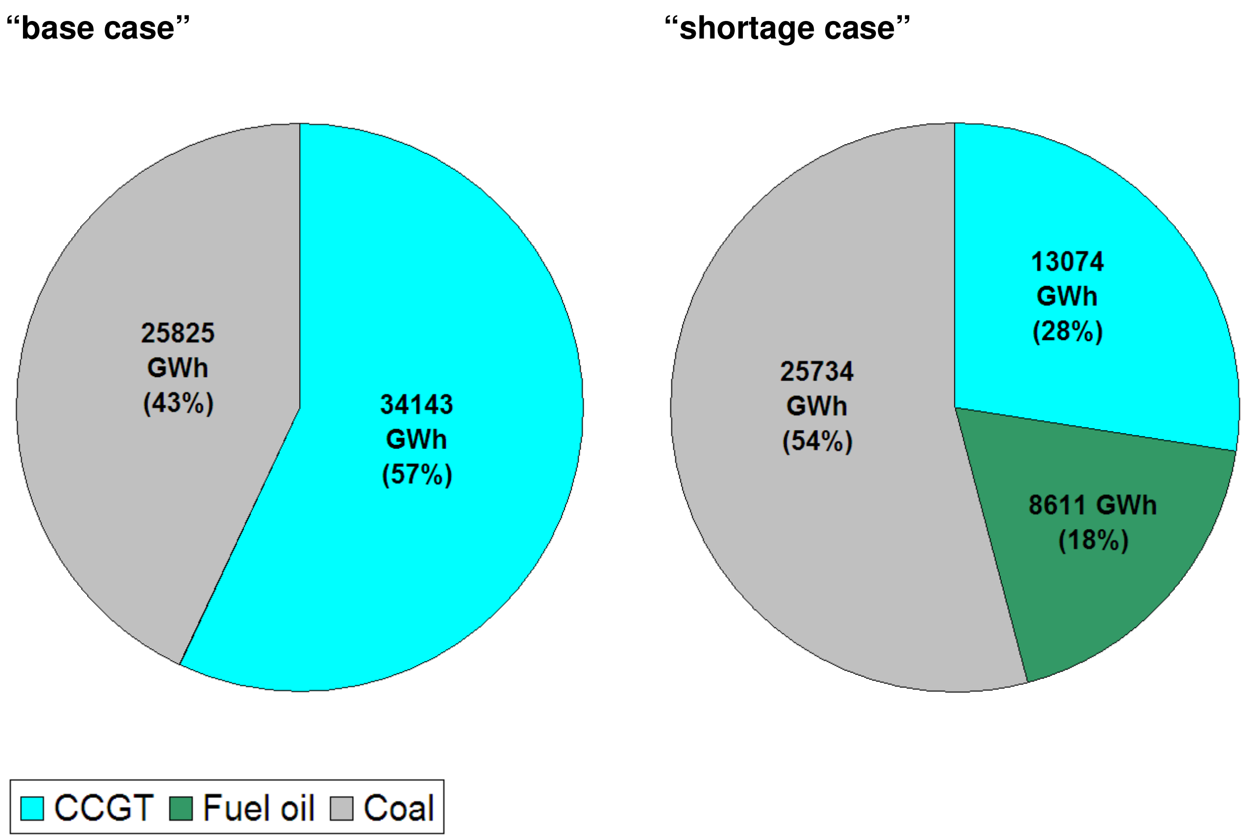

Figure 15: Comparison between non-CHP thermal generation (in GWh) in Italy in the "base case" and in the "shortage case".

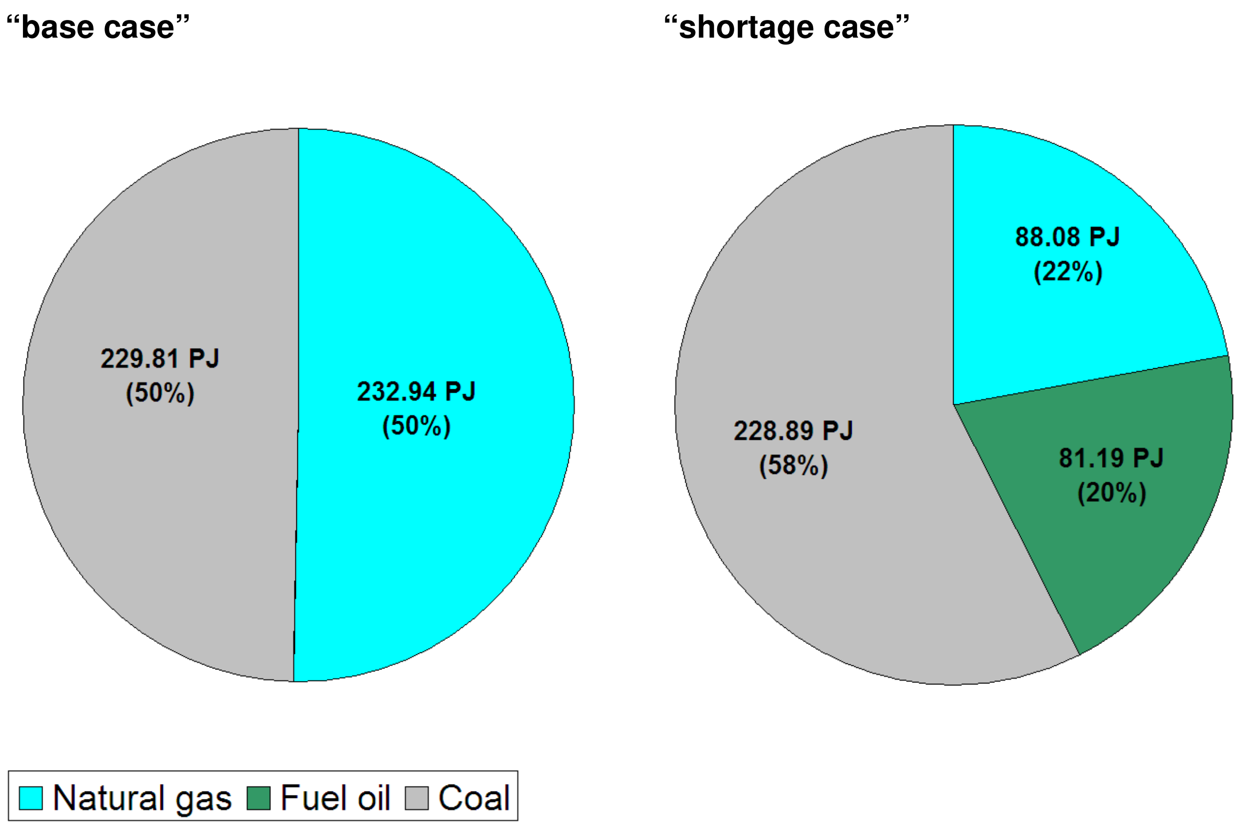

Figure 16: Comparison between non-CHP thermal plants fuel consumption (in PJ) in Italy in the "base case" and in the "shortage case".

Italian neighboring countries

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).

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).

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 0).

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).

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).

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).

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 0), 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).

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 20 (bracketed data in the "shortage case" pie represent the variations w.r.t. the "base case").

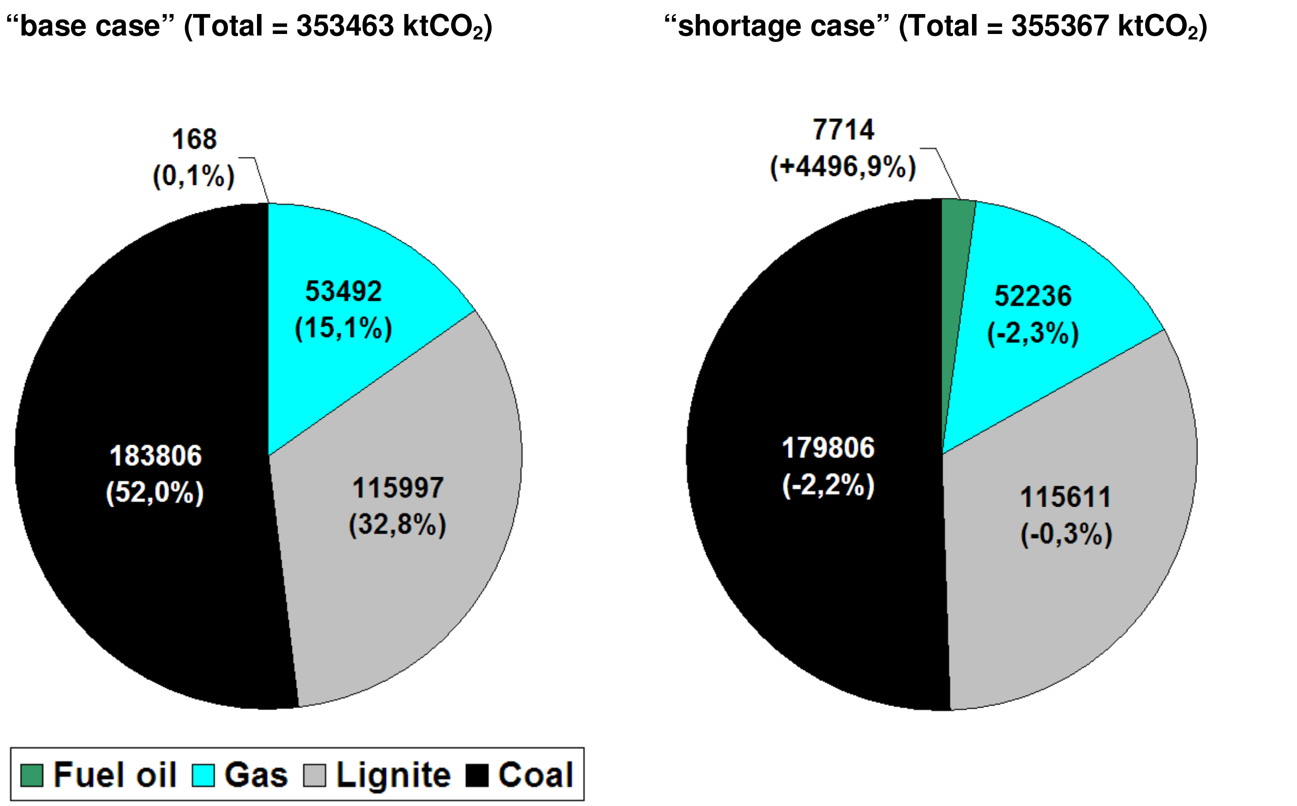

Figure 17: CO_2 emissions of the non-CHP power plants in the modeled power system in the "base case" and in the "shortage case" ($ktCO_2$).

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.

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 0) 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.

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 18 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 19.

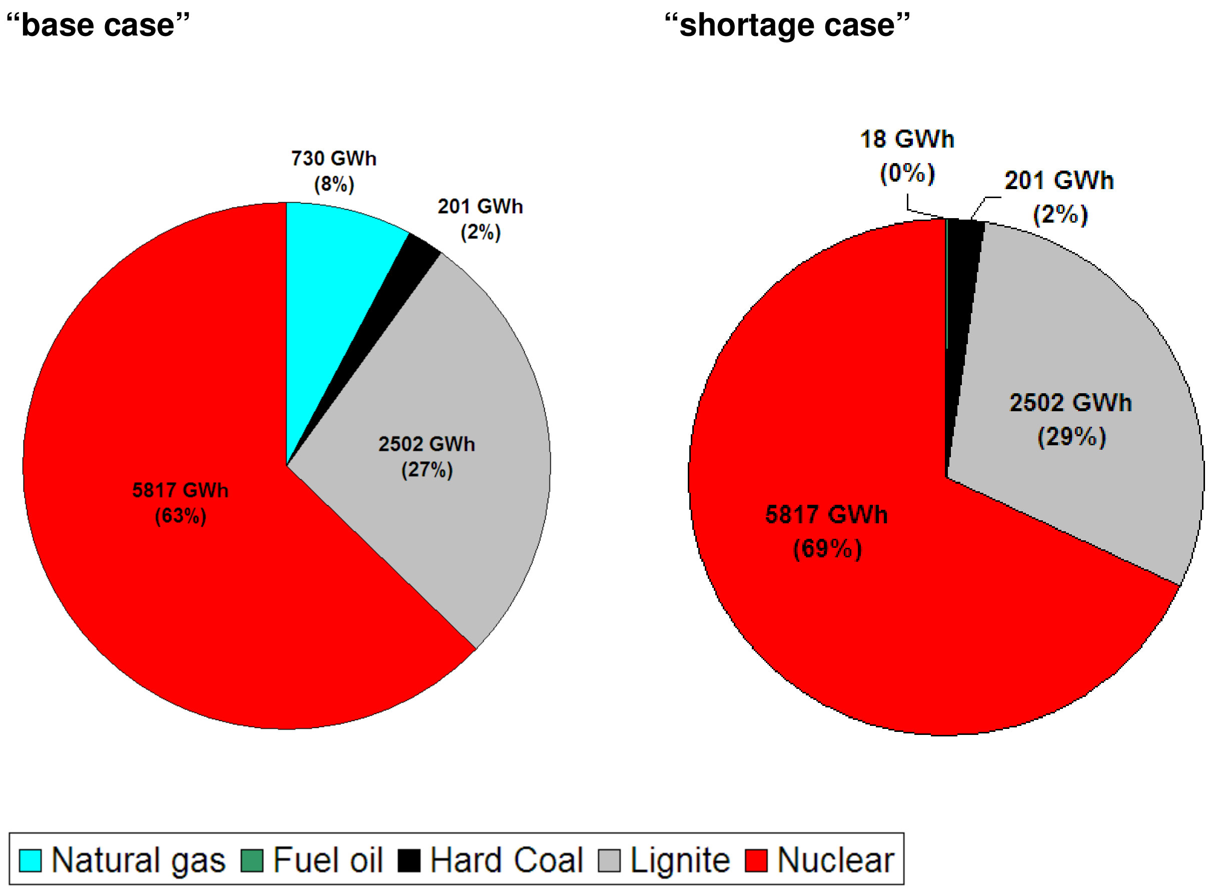

Figure 18: Comparison between non-CHP thermal generation (in GWh) in Hungary in the "base case" and in the "shortage case".

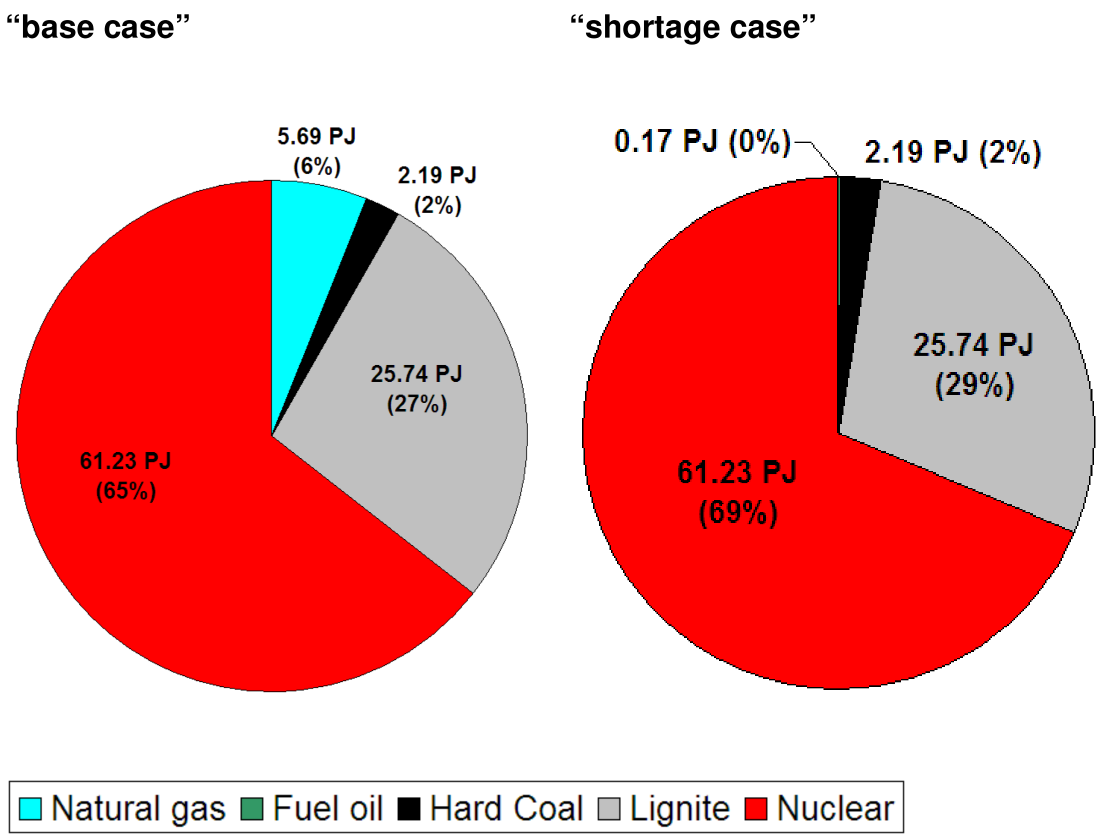

Figure 19: Comparison between non-CHP thermal plants fuel consumption (in PJ) in Hungary in the “base case” and in the “shortage case”.

Hungarian neighboring countries

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).

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).

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).

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).

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).

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).

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]**	**∆%**
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]**	**∆%**
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).

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 20 (bracketed data in the "shortage case" pie represent the variations w.r.t. the "base case").

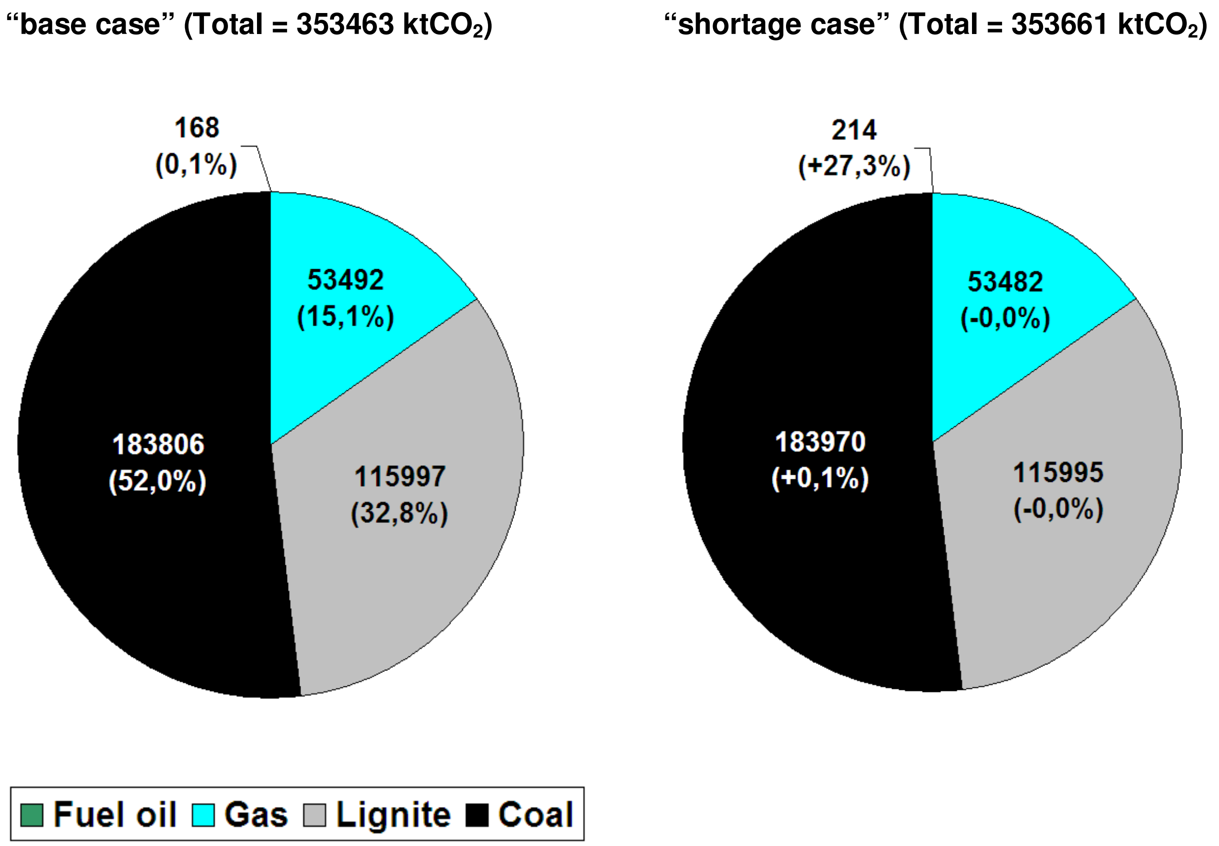

Figure 20: CO_2 emissions of the non-CHP power plants in the modeled power system in the "base case" and in the "shortage case" ($ktCO_2$).

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.

3. 5 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.

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 0.

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.

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.

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 0 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.

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.

Step 6: how remedies should be financed / paid for

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.

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 21 shows the possible financing sources for large LNG projects (see [14]), 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.

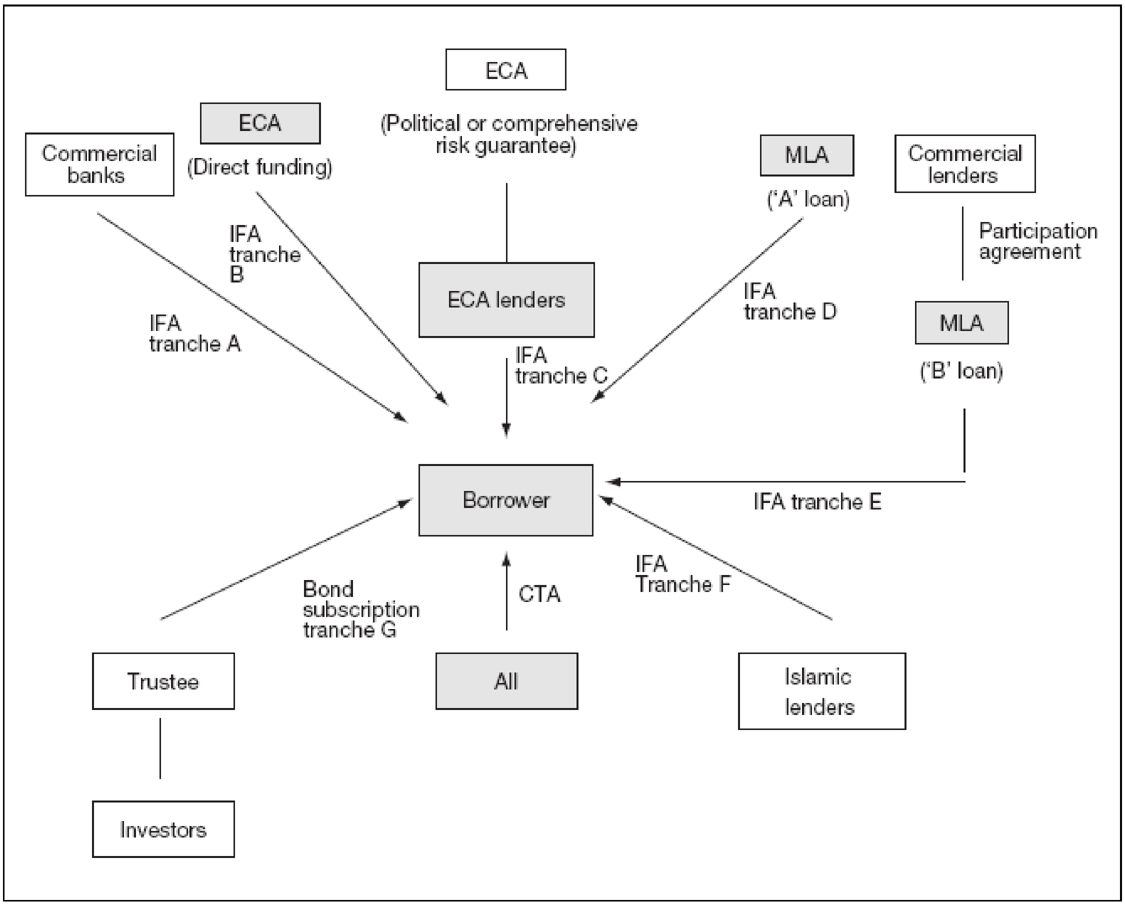

Figure 21: Possible financing sources for large LNG projects (source: [14]).

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.

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.

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.

3 SECURE - A SCENARIO ANALYSIS FOR AN OPTIMAL PAN-EUROPEAN CROSS-BORDER NETWORK DEVELOPMENT

Introduction

This study is aimed to assess the impact of a non-optimal development of the European cross-border electricity transmission network.

The assessment has been carried out by developing and running a model of the European power system (based on the MTSIM simulator, developed by RSE) and is focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO_2 emissions).

In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal developments determined by MTSIM. The reference years considered in the study are 2015 and 2030.

The reference frameworks within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security: *Muddling Through (MT)*, *Europe Alone (EA)* and *Global Regime with Full Trade (GR-FT)*.

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

STEP 1: threat identification and assessment

The threat taken into account in this study is a non-optimal development of the European cross-border electricity transmission network.

Indeed, this is currently not a threat but a fact. Cross-border interconnection capacity was originally developed in Europe for security reasons and for mutual support between different power systems, but, especially after the coming into force of directive 96/92/EC that liberalized the electricity sector with the aim to create a single Internal Electricity Market, cross-border trading activities became more and more important, thus requiring an increase of transmission capacity.

Unfortunately, the development of cross-border transmission network did not keep the pace with the development of demand, of generation and of the related trading needs.

In fact, even today many EU countries do not reach the minimum interconnection level agreed in the EU Council held in Barcelona in March 2002, corresponding to a transmission capacity at least equal to 10% of the installed generation capacity. Such target should have been attained by 2005.

That's why the Council of European Energy Regulators (CEER) in its 2010 work programme (see [16]) plans to produce a *"Status Review on regional electricity interconnection management and use"*, stating that regulators aim *"to create a reliable regulatory climate for new and massive investments in the cross-border capacity that the EU needs."*

Similarly, the European Network of Transmission System Operators for Electricity (ENTSO-E), in its *"Ten year network development plan 2010-2020"* (see [17]) deals with the investment needs on the European power grid, highlighting the insufficiency of cross-border transmission capacity in several frontiers, both in the mid and in the long term.

So, provided that the current status of cross-border transmission infrastructures is definitely non-optimal in Europe, the probability of reaching an optimal status with future developments in the next 10÷20 years is quite low.

In fact, as ENTSO-E highlights in [17], the completion of network projects frequently requires more than 10, and sometimes up to 20 years, when major obstacles are encountered.

Within this context, the main cause of delay are the long permitting procedures involving a multitude of different authorities, typically strongly influenced by the lack of social acceptance that characterizes such kind of projects.

As ENTSO-E states in [17], *"cross-border lines are frequently perceived by the public as mere "transit lines" or "commercial lines" of limited or nil benefit for the local community and therefore, opposition against these lines is often stronger"*.

Moreover, since such projects involve different countries, incongruous permitting procedures can cause additional problems and consequent delays.
Another cause hindering transmission development is related to market uncertainties and the related risks concerning the profitability of the investments, in particular in case of merchant lines.

STEP 2: impact assessment

The non-optimal development of the European cross-border electricity transmission network, as explained in chapter 0, is not a potential threat but a certainty, not only considering the current situation, but also for the next 10÷20 years.

As for the Step 2 of the SECURE methodology, the assessment of the impact of this “threat” would require to define an “optimal” level of network development, and then quantify a “sub-optimal” level to be analyzed in the further steps of the methodology.

In such a case, the definition of an “optimal” level can derive only from the cost assessment carried out in Step 4 of the methodology: please refer to chapter 0 for more details on this issue.

As for the assumptions concerning the “sub-optimal” level, the main references are the estimations made by ERSE within the context of the FP7 research project REALISEGRID (see [18]), together with the cross-border network investments foreseen by ENTSO-E in [17] and [19], focused on interconnections which are expected to be congested in the future, as well as the European Wind Energy Association’s report [20]and the network development plan of the Italian TSO TERNA [21].

In particular, the new interconnections taken into account till 2015 and from 2016 to 2030 are reported in the following Table 64 and Table 65. The abbreviations used in the tables are:

- AL: Albania
- AT: Austria
- BE: Belgium
- BG: Bulgaria
- BH: Bosnia and Herzegovina
- BY: Belarus
- CH: Switzerland
- CZ: Czech Republic
- DE: Germany
- DK_E: Denmark East
- DK_W: Denmark West
- DZ: Algeria
- EE: Estonia
- ES: Spain

- FI: Finland
- FR: France
- GB: Great Britain
- GR: Greece
- HR: Croatia
- HU: Hungary
- IE: Republic of Ireland
- IT: Italy
- KA: Kaliningrad region (Russia)
- LT: Lithuania
- LU: Luxembourg
- LV: Latvia
-
- MD: Moldova
- ME: Montenegro
- MT: Malta
- NI: Northern Ireland
- NL: The Netherlands
- NO: Norway
- PL: Poland
- PT: Portugal
- RO: Romania
- RS: Serbia
- RU: Russia
- SE: Sweden
- SI: Slovenia
- SK: Slovak Republic
- TR: Turkey
- TU: Tunisia
- UA: Rest of Ukraine
- UA_W: Ukraine West

Such investments have been assessed either by each TSO individually or through bilateral grid studies, on the basis of scenario hypotheses used in the Transmission Development Plan of each

TSO. Therefore, they are not the result of a Europe-wide optimization process, like the one that will be carried out in the present study.

Moreover, some of the proposed projects are quite mature (already or nearly under construction), while others are only under study and their probability of realization depends also on the considered time horizon.

It must also be taken into account that the analysis carried out in the present study takes as a reference the main assumptions deriving from the different POLES scenarios, that, in particular in terms of generation / load development, might be different from the scenario hypotheses used by the TSOs that foresaw the aforementioned cross-border network expansions.

Interconnected countries	Type of investment	From - To
AT-HU	New 400 kV AC line	Wien - Győr/Szombathely
NO-DK_W	New HVDC cable (Skagerrak 4)	Kristiansand - Tjele
AT-IT	Upgrading of an existing 110/132 kV line and installation of 2 new PSTs	Steinach - Prati di Vizze
FR-BE	Doubling of an existing 220 kV line and replacement of conductors	Moulaine - Aubange
FR-LU	New 220 kV AC line	Moulaine - Belval
BG-GR	New 400 kV AC line	Maritsa - N. Santa
DE-NL	New double 400 kV AC line	Niederrhein - Doetinchem
DE-PL	Upgrading of an existing 220 kV line and installation of two new 400 kV PSTs	Vierraden - Krajnik
FI-EE	New HVDC cable (Estlink 2)	Anttila - Püssi
ES-FR	New HVDC cable	Santa Llogaia - Baixas
ES-PT	New double 400 kV AC line	Guillena - Tavira
ES-PT	New double 400 kV AC line	Cartelle/Pazos - Recarei
SE-FI	New HVDC cable (Fenno-Skan 2)	Finnböle - Rauma
FR-IT	A new PST and line upgrades with high temperature conductors	Cornier - Venaus
HU-HR	New double 400 kV AC line	Pécs - Ernestinovo
IE-GB	New HVDC cable	Woodland - Deeside
IT-MT	To be defined	To be defined
IT-SI	Installation of a new 400 kV PST	Slovenia
IT-AL	New HVDC cable	Brindisi – Babica
IT-ME	New HVDC cable	Villanova - Tivat
PL-LT	New HVAC line (LitPol) and installation of a back-to-back converter	Elk - Alytus
GB-NL	New HVDC cable (BritNed)	Isle of Grain - Maasvlakte
DK_E-DK_W	New HVDC line (Great Belt)	Herslev - Fraugde
NO-SE	New 420 kV AC line	Nea - Jarpstrommen

Table 64: New cross-border interconnection projects taken into account till 2015.

countries	Type of investment	From - To
RO-RS	New 400 kV AC line	Săcălaz - Novi Sad
HU-SI	New 400 kV AC line	Pince - Cirkovce
PL-SK	New 400 kV AC line	Byczyna - Varin
SI-HR	New 400 kV AC line	Cirkovce - Žerjavinec
DE-PL	New 400 kV AC line	Eisenhüttenstadt - Baczyna/Plewiska
AT-SK	New double 400 kV AC line	Bisamberg/Wien - Stupava
CZ-DE	New double 400 kV AC line	Hradec - Mechlenreuth
HU-SK	New double 400 kV AC line	Győr - Gabčikovo
IT-SI	New double 400 kV AC line	Udine ovest - Okroglo
FR-IT	New HVDC cable	Grande Ile - Piossasco
CH-IT	New HVDC cable	Sils - Verderio
CH-IT	New 400 kV AC line	Lavorgo - Morbegno
AT-IT	New 220 kV AC line	Passo Resia
AT-IT	New 400 kV AC line	Lienz - Cordignano
AT-IT	New cable	Innsbruck - Bressanone
AT-DE	New double 400 kV AC line	St. Peter – Isar/Pleinting
AT-DE	Upgrading of an existing 220 kV line	Westtirol - Memmingen
AT-DE	Upgrading of an existing 220 kV line	Silz - Oberbachern
IT-AL	New HVDC cable	Manfredonia-Kalmet
IT-AL	New HVDC cable	Casamassima-Porto Romano
IT-HR	New HVDC cable	Candia - Konjsko
IE-GB	New HVDC cable	To be defined
NL-NO	New HVDC cable	To be defined
NO-DE	New HVDC cable (Nordlink)	To be defined
NO-DE	New HVDC cable (NorGer)	To be defined
FR-IE	New HVDC cable	To be defined
UK-NO	New HVDC cable	To be defined
SE-LT	New HVDC cable	Nybro - Klaipeda
SE-LV	New HVDC cable	To be defined
IT-TU	New HVDC cable	Partanna - El Aouaria
DZ-ES	New HVDC cable	To be defined
FI-RU	New HVDC line	To be defined
KA-PL	New HVAC line and installation of a back-to-back converter	To be defined
BY-PL	New HVAC line and installation of a back-to-back converter	To be defined
PL-UA	Modernization and re-commissioning of a 750 kV line	Rzeszów - Khmelnitskaya
UA-UA_W	Installation of a back-to-back converter	Zakhidnoukrainska
RO-MD	New 400 kV AC line	Suceava - Bălți
TR-RO	New HVDC cable	Pasakoy - Constanta
HR-BH	New 400 kV AC line	To be defined
BE-DE	New AC or DC line	To be defined
ES-FR	To be defined	To be defined
DK_W-NL	New HVDC cable	Endrup - Eemshaven
IE-NI	New 400 kV AC line	Moyhill - Turleenan
UK-BE	New HVDC cable	Richborough - Zeebrugge
DE-DK_E	New HVDC cable (Kriegers Flak)	Bentwisch - Ishøj/Bjæverskov
NO-SE	New HVDC cable (South West link)	Tveiten - Hurva/Hallsberg
NO-SE	To be defined	To be defined
SE-FI	New 400 kV AC line	To be defined

Table 65: New cross-border interconnection projects taken into account from 2016 to 2030.

STEP 3: assessment of EU vulnerability to energy risks

In order to assess the EU vulnerability to non-optimal development of the cross-border electricity transmission network, we calculated how loaded were the different interconnections in July and in December 2008 (peak load periods), on a monthly average.

The calculations have been done by dividing the monthly energy flows by the maximum amount of energy that could have been transmitted, corresponding to the NTC (Net Transfer Capacity) of each interconnection times the 744 hours of each month (data source: ENTSO-E [2]).

The results are reported in Figure 22 and in Figure 23. The abbreviations used are the following:

- AT: Austria
- BG: Bulgaria
- BL: Belgium and Luxembourg
- BX: Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia, Serbia)
- BT: Baltic countries (Estonia, Latvia and Lithuania)
- CH: Switzerland
- CZ: Czech Republic
- DE: Germany and Denmark West
- ES: Spain
- FI: Finland
- FR: France
- GR: Greece
- HR: Croatia
- HU: Hungary
- IE: Republic of Ireland
- IT: Italy
- NL: The Netherlands
- NO: Norway
- PL: Poland
- PT: Portugal
- RO: Romania
- SE: Sweden and Denmark East

- SI: Slovenia
- SK: Slovak Republic
- UA_W: Ukraine West
- UK: United Kingdom (Great Britain and Northern Ireland)

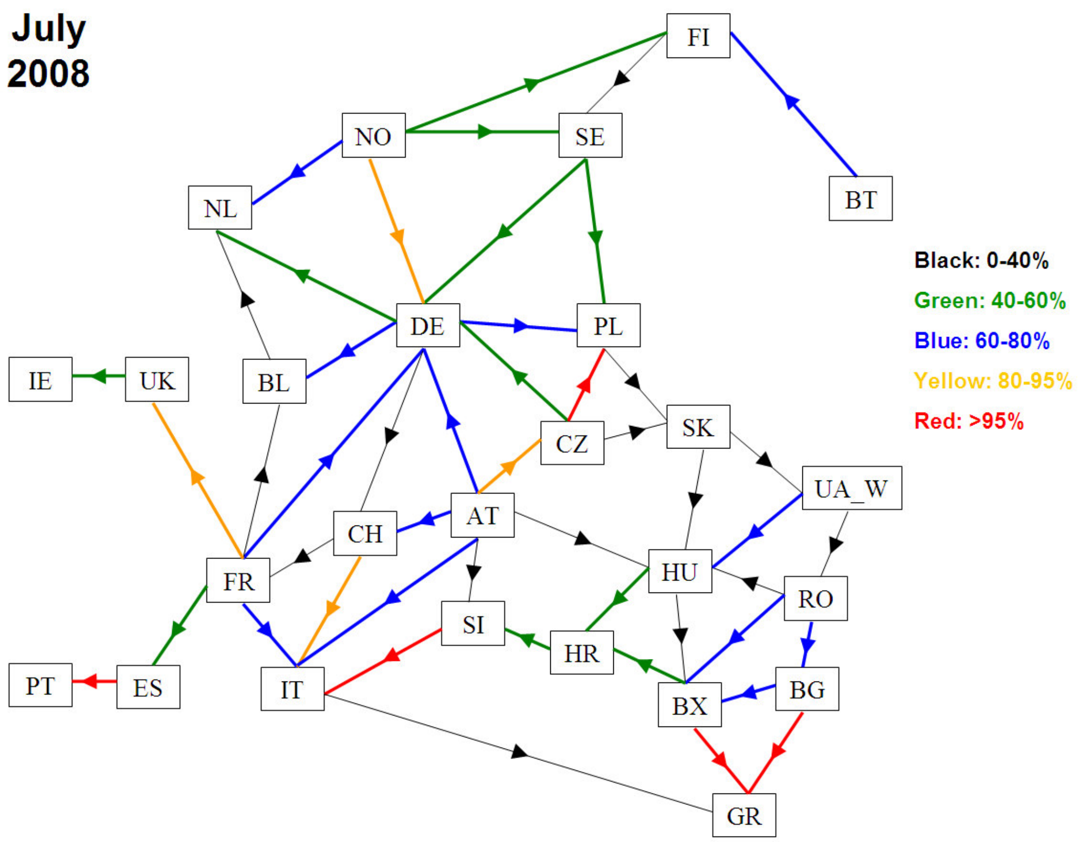

Figure 22: Average loading level of cross-border interconnections in July 2008.

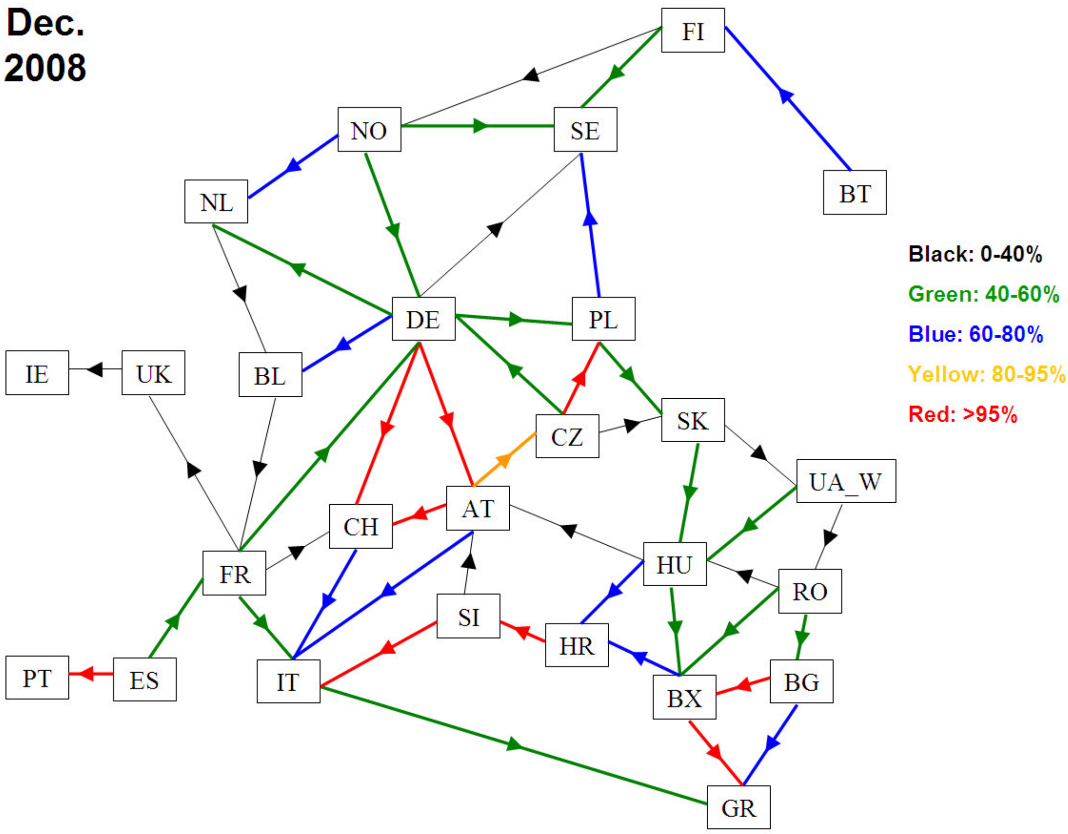

Figure 23: Average loading level of cross-border interconnections in December 2008.

It is evident that several interconnections are highly loaded even on a monthly average: this means that congestion is likely to occur in several hours.

The fact that cross-border congestion is a significant problem in the European power system is clearly shown in Figure 24, reporting the occurrence of congestion in the different frontiers in 2006.

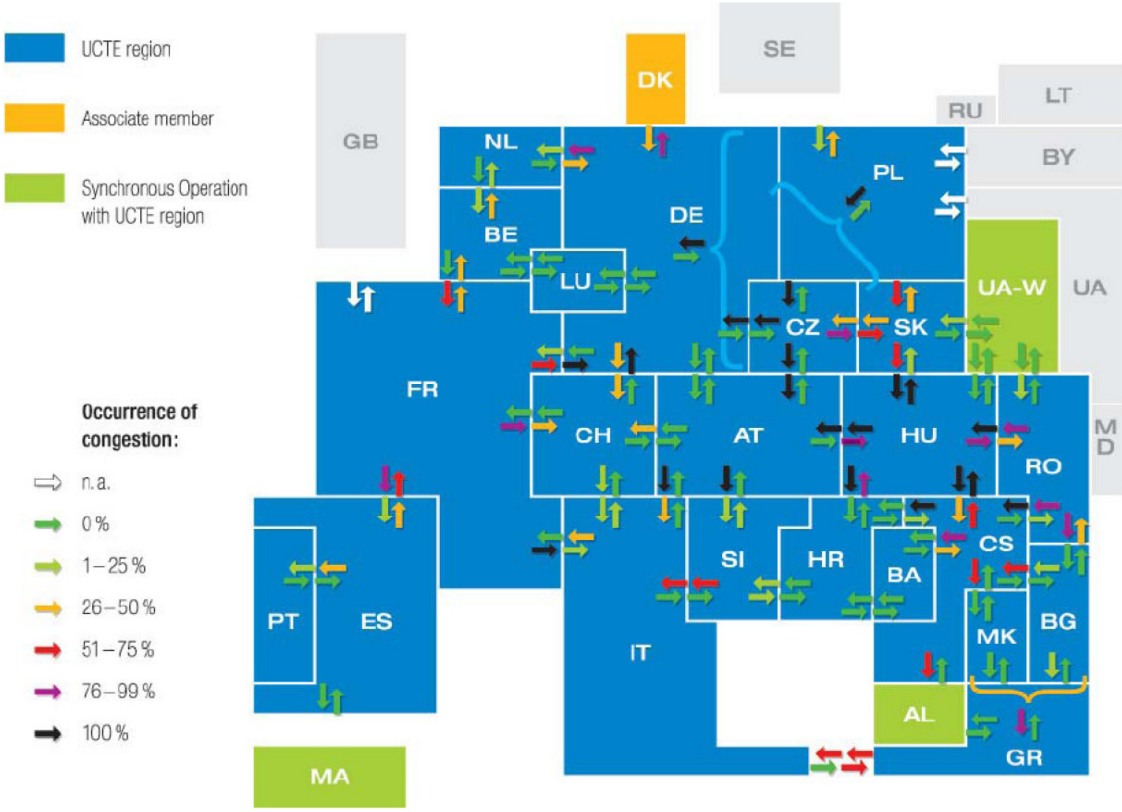

Figure 24: Occurrence of cross-border congestion in continental Europe in 2006 (source: UCTE).

STEP 4: cost assessment

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

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

The assessment has been carried out by developing and running a model of the European power system, based on the MTSIM simulator, developed by RSE.

In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal developments determined by MTSIM.

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

The reference frameworks within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security (see [22]):

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

The reference years considered in the study are 2015 and 2030. It must be noted that, as far as year 2015 is concerned, the various POLES scenarios are quite similar: in fact, their differences become evident mainly after 2020 till 2050, i.e. in the second part of the considered time horizon. Therefore, for the reference year 2015 we will consider only the GR-FT scenario, while for year 2030 all the three POLES scenarios will be taken into account.

The model of the European power system

As a general remark, the model of the European power system used in the present study has been developed starting from the model used in the study reported in chapter 2.

Representation of the transmission network

The European transmission network has been modeled with an equivalent representation 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 NTC values are based on the estimations made in [18].

Since the study will be focused on two reference years, namely 2015 and 2030, two different models of the network, characterized by different foreseen interconnections, have been set up: they are shown in Figure 9 and in Figure 26.

In the figures, cross-border AC interconnections (in black), DC interconnections (in red) and interconnections with other power systems (in blue) are shown.

For the sake of simplicity, in case two synchronous zones are connected by both AC and DC transmission lines (such as Sweden and Finland), a single AC interconnection has been modeled, characterized by the sum of the NTCs of the different lines.

Moreover, AC interconnections equipped with a back-to-back AC-DC-AC converter station (e.g. the new interconnection between Poland and Lithuania) have been modeled in the same way as DC interconnections.

In addition to the abbreviations reported in chapter 0, the following ones are used in the figures:

- BY: Belarus
- DZ: Algeria
- KA: Kaliningrad region (Russia)
- MA: Morocco
- MD: Moldova
- MT: Malta
- RU: Russia
- TR: Turkey
- TU: Tunisia
- UA: Rest of Ukraine

In particular, the model of the European power system developed for the study reported in chapter 0 has been extended to include additional countries, i.e. the United Kingdom, Ireland, Norway, Sweden, Finland, Estonia, Latvia and Lithuania.

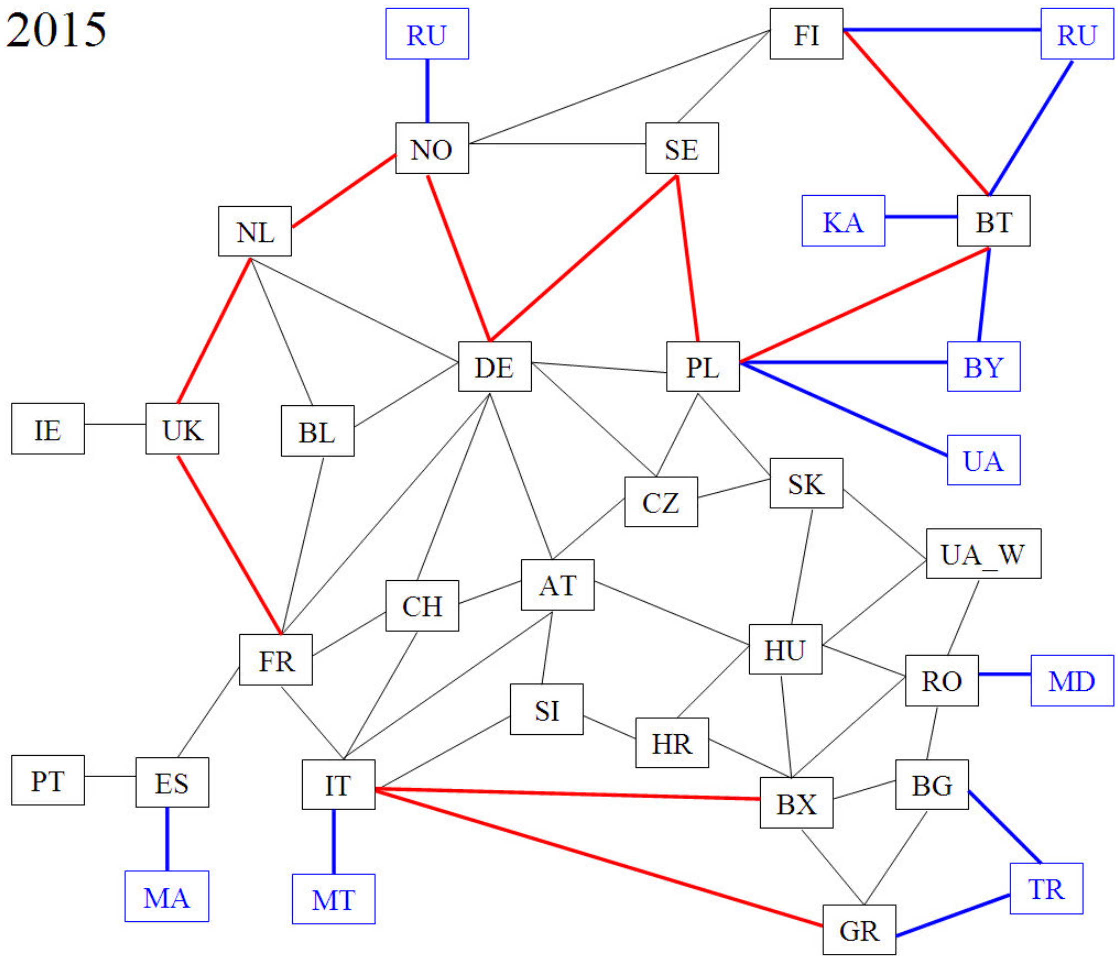

Figure 25: Equivalent representation of the European transmission network in 2015.

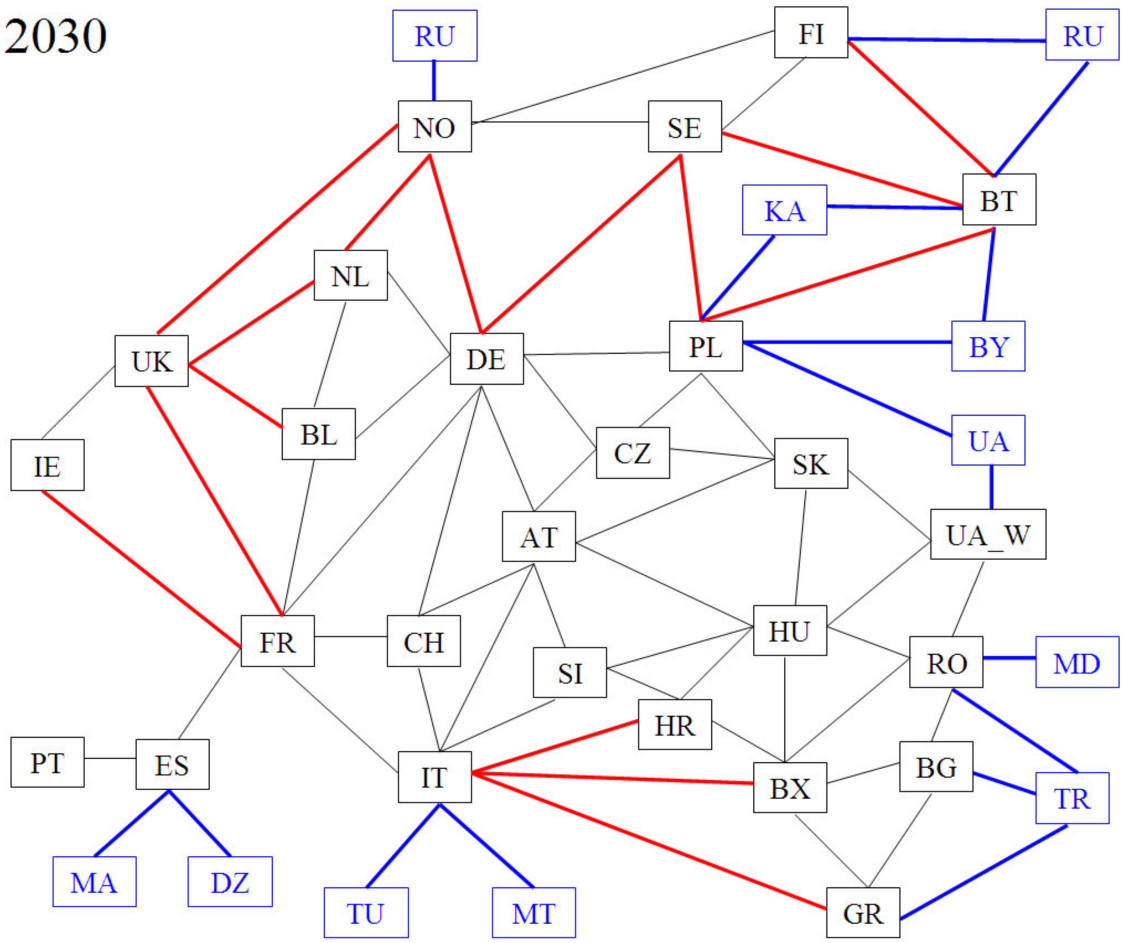

Figure 26: Equivalent representation of the European transmission network in 2030.

The PTDF[30] (*Power Transfer Distribution Factor*) matrix used in the MTSIM simulator has been calculated using an AC transmission grid model, that represents the former UCTE network, with two voltage levels (220 and 380 kV), composed of about 4000 nodes.

As for the 2015 network, PTDFs have been determined on the basis of the aforementioned UCTE system model, executing a series of load flows calculated with the slack node put in Germany.

As for the 2030 network, in order to account for the considered investments in new cross-border lines (see chapter 0) that increase NTC values of some interconnections, new equivalent reactance values have been considered to assess the impact on the corresponding different distribution of power flows.

As for the Nordic transmission grid (basically a triangle composed of Norway, Sweden and Finland: see Figure 9) that is not included in the aforementioned UCTE system model, PTDFs have been calculated on the basis of the NTC values adopted in the different scenarios (the error deriving from this simplification should be acceptable, considering in particular the weakness of the link between Norway and Finland).

As for the Ireland / Great Britain block, PTDFs are quite straightforward, since there is only a single equivalent AC interconnection between the two countries, that are linked to the rest of the European AC network only via DC cables.

As far as the NTC values[31] (for both flow directions) are concerned, they have been determined in [18] starting from the latest ENTSO-E available data (Summer 2009 and Winter 2009-2010: see [2]) and taking into account the future development of each European cross-border interconnection up to either 2015 or 2030 (see chapter 0), the two reference years considered in the present study.

Given the difficulty of estimating, for each cross-border interconnection, both a summer and a winter NTC value, it has been decided to define only a single annual value corresponding to the maximum NTC estimated value (in the vast majority of cases, the winter one).

In the following Table 11, Table 67, Table 68 and
Table 69, NTC values of the cross-border AC and DC interconnections considered for the 2015 and 2030 scenarios are reported.

[30] 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.

[31] What we call here "NTC values" for the sake of brevity should more precisely be intended as "maximum estimated cross-border transmission capacity".

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
PT→ES	3000	3000
ES→FR	2600	2600
FR→IT	3250	1595
IT→CH	1810	4640
FR→CH	3200	2300
FR→DE	2900	3050
FR→BL	4000	3100
CH→DE	3200	1500
DE→BL	980	0
BL→NL	2400	2400
NL→DE	4500	5350
DE→PL	1600	1500
DE→CZ	800	2300
DE→AT	2200	2000
CH→AT	1200	1200
IT→AT	285	300
IT→SI	650	650
PL→CZ	2000	800
PL→SK	600	500
CZ→SK	2000	1000
CZ→AT	2180	1200
SK→HU	1500	600
AT→HU	1500	1200
AT→SI	900	900
HU→BX	600	600
HU→RO	600	1400
BX→BG	750	1100
BX→RO	300	650
RO→BG	950	950
BG→GR	1500	1400
BX→GR	500	600
HR→BX	1060	1050
HR→SI	1000	1000
HR→HU	3000	2500
RO→UA_W	400	400
HU→UA_W	650	650
SK→UA_W	400	400
UK→IE	950	580
NO→SE	3550	3350
SE→FI	2550	2450
FI→NO	100	100

Table 66: NTC values (MW) of the considered AC cross-border interconnections in the 2015 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
PT→ES	3000	3000
ES→FR	4000	4000
FR→IT	4200	2595
IT→CH	3710	6540
FR→CH	3200	2300
FR→DE	2900	3050
FR→BL	4000	3100
CH→DE	3200	1500
DE→BL	1980	1000
BL→NL	2400	2400
NL→DE	5100	5950
DE→PL	2500	2400
DE→CZ	2300	3800
DE→AT	6880	6880
CH→AT	1400	1400
IT→AT	2200	2200
IT→SI	2150	2150
PL→CZ	2000	800
PL→SK	1500	1400
CZ→SK	2000	1000
CZ→AT	2000	1100
SK→HU	3000	2100
AT→HU	1500	1200
AT→SI	1200	1200
SI→HU	900	900
SK→AT	1500	1500
AT→SI	1200	1200
HU→BX	600	600
HU→RO	600	1400
BX→BG	750	1100
BX→RO	500	850
RO→BG	950	950
BG→GR	1500	1400
BX→GR	500	600
HR→BX	2210	2200
HR→SI	1900	1900
HR→HU	3000	2500
RO→UA_W	400	400
HU→UA_W	650	1150
SK→UA_W	400	400
UK→IE	1300	930
NO→SE	5450	5250
SE→FI	2800	2700
FI→NO	100	100

Table 67: NTC values (MW) of the considered AC cross-border interconnections in the 2030 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
IT→GR	500	500
FR→UK	2000	2000
UK→NL	1320	1320
DE→NO	1600	1600
DE→SE	1890	1830
PL→BT	500	500
FI→BT	1000	1000
NO→NL	700	700
SE→PL	600	600
BX→IT	1500	1500

Table 68: NTC values (MW) of the considered DC cross-border interconnections in the 2015 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
IT→GR	500	500
IT→BX	3000	3000
IT→HR	1000	1000
FR→IE	1000	1000
FR→UK	3000	3000
UK→BL	1000	1000
UK→NL	1320	1320
UK→NO	1400	1400
NL→NO	1400	1400
DE→NO	4000	4000
DE→SE	2490	2430
SE→PL	600	600
PL→BT	1000	1000
SE→BT	1700	1700
FI→BT	1000	1000

Table 69: NTC values (MW) of the considered DC cross-border interconnections in the 2030 scenarios.

As far as the electricity exchanges via DC interconnections are concerned, their hourly profiles have not been exogenously imposed, but they have been determined by the MTSIM simulator, basically on the basis of the hourly electricity price differences between the zones they connect.

As for AC and DC interconnections with other power systems, hourly profiles have been imposed. In particular, for each interconnection, firstly the prevailing direction of annual net power exchanges has been envisaged. Then, the NTC value and the annual net electricity exchange have been hypothesized. Finally, this latter value has been profiled in accordance with the load profile of the importing country.

In the following Table 70 and Table 71, the NTC values and the annual net electricity exchanges imposed on the considered AC and DC interconnections with other power systems are reported [18].

Interconnection (A→B)	NTC values (A→B) [MW]	Net exchanges (A→B) [GWh]
KA→BT	680	1500
RU→BT	400	1300
BY→BT	1400	2453
RU→FI	1400	9600
RU→NO	50	220
BY→PL	120	521
UA→PL	248	760
MD→RO	600	2891
TR→BG	500	3066
TR→GR	500	3066
IT→MT	200	876
ES→MA	900	5519

Table 70: NTC values (MW) and annual net electricity exchanges (GWh) imposed on the considered AC and DC interconnections with other power systems in the 2015 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	Net exchanges (A→B) [GWh]
KA→BT	1000	3000
KA→PL	600	3000
RU→BT	400	2000
BY→BT	1400	0
RU→FI	1900	12600
RU→NO	50	220
BY→PL	1000	6000
UA→PL	1448	8118
UA→UA_W	500	3000
MD→RO	1500	7227
TR→RO	600	3679
TR→BG	500	3066
TR→GR	800	4906
IT→MT	200	1314
TU→IT	1000	6570
DZ→ES	1000	6570
ES→MA	1400	8585

Table 71: NTC values (MW) and annual net electricity exchanges (GWh) imposed on the considered AC and DC interconnections with other power systems in the 2030 scenarios.

Representation of the power generation system

As shown in Figure 9 and in Figure 26, 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 particular, for the reference year 2015 the same net generation capacity values (for each technology/fuel) defined for the study reported in [23] have been used, with some minor updates.
They have been taken from the “Conservative Scenario” (Scenario A) of the UCTE (now ENTSO-E) *System Adequacy Forecast (SAF) 2009-2020* (available from [20]). 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 [18]), as well as estimated by RSE.
As for the countries that have been added to the model described in [23] (i.e. the United Kingdom, Ireland, Norway, Sweden, Finland, Estonia, Latvia and Lithuania), the net generation capacity data have been taken from the respective Transmission System Operators’ annual statistics (see [24]) and system adequacy reports (see [25], [26] and[27]), or from the electricity market operator’s website (see [28]) and from other sources (see [29]).
As for the reference year 2030, all generation capacity data have been derived from the results of the three POLES scenarios MT, EA and GR-FT. It must be taken into account that POLES does not model a minimum size for power plants of the different technologies, therefore in some cases generation capacity data well below a realistic plant size are reported: such data, that are basically negligible, have not been considered in the model implemented with MTSIM.

Fossil fuelled thermal power plants

In addition to conventional fossil fuelled generation technologies considered in the study reported in [23], hard coal-fired USC, CCGT and IGCC power plants equipped with Carbon Capture and Storage (CCS) technology have been added.
In the following, data already reported in a detailed manner in the tables contained in [23] are aggregated under the item “Rest of Europe”. Data concerning Germany + Denmark West (DE) for year 2015 have been slightly modified w.r.t. the data reported in [23], therefore, for the sake of clarity, they have not been aggregated under the item “Rest of Europe”.

Net generation capacity

- <u>*Total generation capacity*</u>

In the following Table 13 and Table 73, for each country, data concerning the total fossil fuelled generation capacity installed in the 2015 and in the 2030 scenarios are reported.

Country	Net generation capacity [MW]
BT	5696
DE	109515
FI	13810
IE	5679
NO	979
SE	19626
UK	89191
Rest of Europe	384102
Total	**628598**

Table 72: Total fossil fuelled generation capacity (MW) installed in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	**EA**	**GR-FT**
AT	6671	5249	5576
BG	7177	4139	4443
BL	18307	18617	18746
BT	5899	5146	5693
BX	11216	10319	9915
CH	4824	4215	4414
CZ	17189	14954	15127
DE	82527	61409	69345
ES	64744	57897	60395
FI	15143	10376	11166
FR	105405	103163	108884
GR	13443	11161	12071
HR	3087	2845	2769
HU	8477	7229	7598
IE	5642	3622	5224
IT	55650	52603	52937
NL	23485	14618	14774
NO	4838	4376	4122
PL	33607	31525	32512
PT	10923	8665	9584
RO	9555	7518	8151
SE	16911	11759	12785
SI	3254	3022	3197
SK	4949	4523	4759
UA_W	4078	4057	3991
UK	78372	82235	81951
Total	**615373**	**545242**	**570129**

Table 73: Total fossil fuelled generation capacity (MW) installed in the 2030 scenarios.

- *CHP generation capacity*

In the following
Table 14, Table 75 and Table 76 the net generation capacity and the estimated electricity production of the fossil fuelled and RES CHP power plants for each country are reported.

Just like in [23], 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]**
BT	3230	1780
DE	24580	88020
FI	5820	27920
IE	270	1780
NO	191	150
SE	6070	18500
UK	5470	25340
Rest of Europe	68676	277259
Total	**114307**	**440749**

Table 74: Net generation capacity (MW) and estimated electricity production (GWh) of CHP power plants in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1925	1647	1752
BG	362	374	385
BL	698	636	666
BT	281	247	275
BX	130	130	123
CH	311	322	235
CZ	1219	1116	1159
DE	4526	4111	4245
ES	14726	13104	13692
FI	1716	1375	1574
FR	2207	1888	1999
GR	223	205	221
HR	20	20	19
HU	326	302	322
IE	466	439	465
IT	15110	14168	14525
NL	2084	1830	1929
NO	311	322	235
PL	1095	1167	1248
PT	870	773	826
RO	368	301	335
SE	563	491	537
SI	418	354	377
SK	76	69	77
UA_W	200	200	200
UK	12344	10999	11597
Total	**62575**	**56590**	**59018**

Table 75: Net generation capacity (MW) of fossil fuelled CHP power plants in the 2030 scenarios.

Country	Electricity production [GWh]		
	MT	EA	GR-FT
AT	5728	4884	5202
BG	1080	1116	1150
BL	2086	1898	1991
BT	843	740	824
BX	387	387	366
CH	933	966	703
CZ	3661	3349	3479
DE	13215	11960	12367
ES	43732	38824	40606
FI	5128	4092	4694
FR	6397	5433	5768
GR	671	615	666
HR	60	60	57
HU	978	906	967
IE	1395	1314	1393
IT	45143	42283	43366
NL	6041	5271	5568
NO	933	966	703
PL	3306	3522	3771
PT	2586	2292	2454
RO	1113	909	1012
SE	1685	1465	1607
SI	1260	1066	1136
SK	224	202	227
UA_W	572	572	569
UK	36684	32604	34416
Total	**185841**	**167696**	**175062**

Table 76: Estimated electricity production (GWh) of fossil fuelled CHP power plants in the 2030 scenarios.

- *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, considered in the 2015 scenario are reported.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BT	793	2036	2829
DE	5264	236	5500
FI	220	175	395
SE	2791	0	2791
UK	3694	0	3694
Rest of Europe	16614	771	17385
Total	**29376**	**3218**	**32594**

Table 77: Net generation capacity (MW) of fuel oil-fired steam turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BT	1787	104	1891
DE	3359	393	3752
FI	185	625	810
IE	258	0	258
SE	560	346	906
Rest of Europe	15178	1938	17116
Total	**21327**	**3406**	**24733**

Table 78: Net generation capacity (MW) of natural gas-fired steam turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
DE	31970	10555	42525
FI	2159	1010	3169
IE	848	0	848
SE	753	1934	2687
UK	29510	0	29510
Rest of Europe	50009	11157	61166
Total	**115249**	**24656**	**139905**

Table 79: Net generation capacity (MW) of hard coal-fired steam turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
DE	16008	4592	20600
FI	170	513	683
IE	346	0	346
Rest of Europe	28251	15588	43839
Total	**44775**	**20693**	**65468**

Table 80: Net generation capacity (MW) of lignite/peat-fired steam turbine power plants (2015).

In the following tables, for each country, the net generation capacities of the different kinds of steam turbine power plants considered in the three different 2030 scenarios are reported.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	334	297	304
BG	162	152	154
BL	785	762	767
BT	1022	998	1003
BX	486	482	447
CZ	331	309	313
DE	1955	1650	1770
ES	3388	3315	3321
FI	301	277	280
FR	4582	4438	4459
GR	1326	1300	1306
HU	336	315	320
IE	133	127	129
IT	2904	2904	2904
NL	282	278	279
NO	409	403	390
PL	853	779	795
PT	1116	1110	1112
RO	1348	1321	1326
SE	1289	1282	1284
SK	331	320	324
UK	2017	2008	2011
Total	**25690**	**24827**	**24998**

Table 81: Net generation capacity (MW) of fuel oil-fired steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	399	131	178
BL	2824	2670	2614
BT	679	613	604
BX	458	500	458
DE	3359	1847	2186
FI	185	185	185
HU	895	802	814
IT	6403	6403	6403
PT	959	782	747
SE	560	543	560
Total	**16721**	**14476**	**14749**

Table 82: Net generation capacity (MW) of natural gas-fired steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1309	1067	1118
BG	1054	706	738
BL	2459	2407	2514
BT	1612	944	1237
CH	67	92	84
CZ	1076	841	883
DE	18536	17677	18384
ES	5775	4810	5197
FI	2290	2291	2291
FR	12078	9672	10858
GR	853	512	589
HR	587	543	490
HU	251	139	197
IE	850	613	703
IT	1892	1888	1893
NL	2262	2064	2071
NO	121	76	69
PL	9271	7428	7801
PT	1553	1097	1210
RO	1066	757	857
SE	1873	1313	1445
SI	229	196	207
SK	620	473	488
UA_W	2002	1990	1955
UK	6964	6963	7117
Total	**76650**	**66559**	**70396**

Table 83: Net generation capacity (MW) of hard coal-fired steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	440	49	131
BG	1224	61	171
BL	6300	2303	3777
BT	1023	237	479
BX	141	120	63
CH	263	359	204
CZ	3988	916	1517
DE	28178	5476	11039
ES	12923	2449	5497
FI	2400	54	179
FR	13689	2562	5282
GR	1429	473	798
HR	41	35	18
HU	1519	281	550
IE	2024	283	918
IT	5131	1246	2249
NL	6376	785	909
NO	480	297	170
PL	8814	1822	3571
PT	4064	982	1900
RO	1728	228	561
SE	3708	487	1081
SI	639	144	277
SK	795	132	294
UK	14051	3071	5958
Total	**121368**	**24852**	**47593**

Table 84: Net generation capacity (MW) of hard coal-fired USC steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	3	6	1
BG	30	51	91
BL	117	4257	3171
BT	9	404	381
BX	0	0	9
CH	0	0	42
CZ	93	1604	1436
DE	519	6676	7166
ES	249	5267	4843
FI	42	15	90
FR	254	4633	4319
GR	17	553	452
HR	0	0	3
HU	30	581	497
IE	37	406	883
IT	65	1913	1539
NL	120	464	432
NO	0	0	34
PL	200	4573	3974
PT	67	1455	1294
RO	38	584	535
SE	33	277	297
SI	13	240	229
SK	18	306	302
UK	243	6396	5282
Total	**2197**	**40661**	**37302**

Table 85: Net generation capacity (MW) of hard coal-fired USC steam turbine power plants with CCS (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
BG	1861	1247	1304
BX	4596	4235	3780
CZ	6038	4719	4958
DE	9068	8626	8989
ES	2590	2157	2331
FI	180	180	180
GR	5130	3075	3540
HU	1730	956	1177
IE	347	249	286
PL	5573	5573	5573
RO	2091	1484	1682
SI	840	719	757
SK	451	344	355
Total	**40495**	**33564**	**34912**

Table 86: Net generation capacity (MW) of lignite/peat-fired steam turbine power plants (2030).

- *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 and of IGCC CCS power plants, both non-CHP and CHP, considered in the 2015 scenario are reported.

Country	**Net generation capacity [MW]**		
	non-CHP	**CHP**	**Total**
DE	7098	2462	9560
FI	840	0	840
IE	1072	127	1199
NO	249	0	249
SE	418	70	488
UK	589	158	747
Rest of Europe	9333	5860	15193
Total	**19599**	**8677**	**28276**

Table 87: Net generation capacity (MW) of open cycle gas turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BT	11	698	709
DE	10735	5043	15778
FI	1875	1742	3617
IE	2885	143	3028
NO	730	0	730
SE	2214	512	2726
UK	38055	4416	42471
Rest of Europe	97957	32881	130838
Total	**154462**	**45435**	**199897**

Table 88: Net generation capacity (MW) of combined cycle gas turbine power plants (2015).

Country	Net generation capacity [MW]
UK	3325
Rest of Europe	0
Total	**3325**

Table 89: Net generation capacity (MW) of IGCC CCS power plants (2015).

In the following tables, for each country, the net generation capacities of open cycle and combined cycle gas turbine power plants (without and with CCS) considered in the three different 2030 scenarios are reported.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1468	1468	1468
BG	573	361	390
BL	246	177	177
BX	1788	1670	1670
CH	253	243	242
CZ	826	646	633
DE	7658	7542	7542
ES	7968	5962	5502
FI	2592	2455	2599
FR	9537	7631	9070
GR	1712	1338	1467
HR	1365	1301	1243
HU	584	584	584
IE	831	718	839
IT	4111	2904	2346
NL	5065	4711	4781
NO	2746	2607	2591
PL	2302	1675	1751
PT	532	532	532
RO	1845	1739	1741
SE	2867	2193	2289
SI	215	220	208
SK	770	732	744
UA_W	412	409	375
UK	6625	6273	6396
Total	**64891**	**56091**	**57180**

Table 90: Net generation capacity (MW) of open cycle gas turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	758	534	603
BG	322	112	141
BL	1649	1686	1619
BT	233	201	214
BX	1633	1475	1046
CH	106	92	54
CZ	552	300	351
DE	8466	6265	6880
ES	9522	8459	8534
FI	2494	974	1248
FR	4856	3425	3894
GR	877	834	834
HR	496	449	321
HU	624	515	542
IE	817	665	684
IT	19411	14498	16966
NL	3799	3443	3424
NO	771	671	606
PL	1433	573	976
PT	1227	963	1035
RO	227	106	154
SE	1517	642	816
SI	47	30	34
SK	437	317	358
UA_W	1019	1027	599
UK	19680	15757	16891
Total	**82973**	**64013**	**68824**

Table 91: Net generation capacity (MW) of combined cycle gas turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1	49	19
BG	3	10	4
BL	10	422	215
BT	1	27	14
BX	0	1	217
CH	0	0	33
CZ	10	229	149
DE	104	1441	1070
ES	84	2151	1420
FI	16	78	48
FR	36	771	491
GR	1	167	118
HR	0	0	63
HU	5	96	63
IE	4	48	84
IT	211	5974	3455
NL	0	67	45
NO	0	0	27
PL	25	753	455
PT	4	225	148
RO	3	62	38
SE	4	70	30
SI	0	23	15
SK	4	72	53
UA_W	5	6	229
UK[32]	3539	9445	7262
Total	**4070**	**22187**	**15765**

Table 92: Net generation capacity (MW) of combined cycle gas turbine power plants with CCS (2030).

- *Nuclear power plants*

In the following Table 22 and Table 94, for each country, the net generation capacities of nuclear power plants in the 2015 and in the 2030 scenarios are reported.

Country	Net generation capacity [MW]
DE	11800
FI	4296
SE	10028
UK	9444
Rest of Europe	95002
Total	**130570**

Table 93: Net generation capacity (MW) of nuclear power plants in the 2015 scenario.

[32] Including 3325 MW of IGCC CCS power plants.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	34	1	2
BG	1586	1065	1065
BL	3219	3297	3226
BT	1039	1475	1486
BX	1984	1706	2102
CH	3824	3107	3520
CZ	3056	4274	3728
DE	158	98	74
ES	7519	10223	10058
FI	2927	2492	2492
FR	58166	68143	68512
GR	1875	2704	2746
HR	578	497	612
HU	2177	2658	2532
IE	133	74	233
IT	412	705	657
NL	3497	976	904
NO	0	0	0
PL	4041	7182	6368
PT	531	746	780
RO	841	936	922
SE	4497	4461	4446
SI	853	1096	1093
SK	1447	1758	1764
UA_W	440	425	633
UK	12909	21323	19437
Total	**117743**	**141422**	**139392**

Table 94: Net generation capacity (MW) of nuclear power plants in the 2030 scenario.

Electrical efficiencies

The ranges of the average electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the different countries in the 2015 and 2030 scenarios are reported in the following Table 95.

Technology	Efficiency [%]
Oil fired steam turbine	34 ÷ 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
IGCC CCS	45
Nuclear	30 ÷ 36

Table 95: Ranges of the electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the 2015 scenario.

Technology	Efficiency [%]
Oil fired steam turbine	34 ÷ 36
Natural gas fired steam turbine	32 ÷ 38.8
Repowering	39.7
Hard coal fired steam turbine	33 ÷ 45
Hard coal fired USC steam turbine	48
Hard coal fired USC steam turbine with CCS	44
Lignite fired steam turbine	32 ÷ 35
Open Cycle Gas Turbine	28.1 ÷ 37
Combined Cycle Gas Turbine	55 ÷ 60
Combined Cycle Gas Turbine with CCS	55
IGCC with CCS	45
Nuclear	30 ÷ 36

Table 96: Ranges of the electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the 2030 scenarios.

Forced and scheduled unavailability

In the following Table 97, forced (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 229) 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	0.055	35
Hard coal fired USC steam turbine	0.055	35
Hard coal fired USC steam turbine with CCS	0.055	35
Lignite fired steam turbine	0.113	70
Open Cycle and Combined Cycle Gas Turbine	0.05	35
Combined Cycle Gas Turbine with CCS	0.05	35
IGCC with CCS	0.05	35
Nuclear	0.001 ÷ 0.293	25

Table 97: Forced (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 98) 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 98: Distribution over the year of the scheduled unavailability adopted for the fossil fuelled generation technologies.

CO_2 emission rates of fossil fuels

In the following Table 99, CO_2 emission rates of the different fossil fuels adopted for the simulations are reported. Such data, together with plant efficiencies (see Table 99), 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
Coal with CCS	0.009
Gas with CCS	0.008

Table 99: CO_2 emission rates (tCO_2/GJ) of the different fossil fuels.

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 of the countries not considered in the study reported in [23], the average values of all the years available in the corresponding annual energy statistics (see [24], [31],[32] and [33]) have been taken into account for the 2015 scenario.

On the other hand, concerning the 2030 scenarios, the annual electricity hydro production data have been taken from the results of the three POLES scenarios (MT, EA and GR-FT). The subdivision of hydro production into the different plant typologies (not available from POLES, just like generation capacity) has been done proportionally to the 2015 subdivision.

As for the annual electricity consumption of pumped storage hydro power plants, since the weight of natural inflows on their production is not known, so that consumption cannot be calculated from production, it has been decided to use the same values of the 2015 scenario in all the three 2030 scenarios.

The following Table 100 reports the total net hydro generation capacity assumed for the simulations in the different countries in the 2030 scenarios.

Country	Net generation capacity [MW]		
	MT	**EA**	**GR-FT**
AT	20619	20575	20549
BG	2703	2774	2742
BL	2690	2727	2718
BT	2688	2769	2768
BX	11192	11161	10789
CH	14270	14271	14272
CZ	3126	3202	3175
DE	12073	12359	12301
ES	23349	23809	23769
FI	4282	4229	4226
FR	33720	32996	32944
GR	3529	3648	3639
HR	3506	3496	3379
HU	75	77	77
IE	580	587	585
IT	26633	28386	28223
NL	50	50	49
NO	31556	31558	31560
PL	2881	2984	2975
PT	8403	8615	8571
RO	9888	9259	9241
SE	42223	42072	42137
SI	1609	1493	1486
SK	3556	3588	3587
UA_W	27	27	27
UK	5128	5220	5210
Total	**270356**	**271932**	**270999**

Table 100: Total net hydro generation capacity (MW) assumed for the simulations in the different countries in the 2030 scenarios.

More details, according to the plant type, are provided in the following, where data already reported in a detailed manner in the tables contained in [23] are aggregated under the item “Rest of Europe”.

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 in the 2015 scenario are reported in the following Table 101.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
BT	1572	1413	501	577	769	3260
FI	3147	3453	2982	2978	3526	12939
IE	238	84	51	100	132	367
UK	1127	683	317	817	1135	2952
Rest of Europe	39730	38872	37618	29947	31584	138021
Total	**45814**	**44505**	**41469**	**34419**	**37146**	**157539**

Table 101: Run of river hydro generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries.

In the following tables, data concerning seasonal production of run of river hydro power plants in the 2030 scenarios are reported.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	9734	11314	8220	6672	35940
BG	348	288	189	272	1097
BL	42	41	36	35	154
BT	1659	588	678	903	3828
BX	10288	6346	7168	9958	33760
CH	3948	5771	4109	3368	17196
CZ	108	69	68	87	332
DE	1932	1995	1640	1640	7207
ES	3271	2429	2004	2696	10400
FI	5026	4340	4335	5133	18834
FR	11798	9891	7792	9408	38889
GR	68	62	41	60	231
HR	1538	979	1005	1505	5027
HU	51	65	59	52	227
IE	121	74	145	191	531
IT	4975	6255	4621	4144	19995
NL	39	25	22	41	127
PL	747	529	547	650	2473
PT	1537	924	1054	1553	5068
RO	4413	4298	3419	3401	15531
SI	1396	1499	1235	904	5034
SK	1664	1299	940	1133	5036
UA_W	51	31	24	28	134
UK	1777	826	2125	2954	7682
Total	**66531**	**59938**	**51476**	**56788**	**234733**

Table 102: Run of river hydro seasonal production (GWh) assumed for the simulations in the different countries in the MT 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	9704	11279	8195	6652	35830
BG	357	295	193	279	1124
BL	41	37	36	43	157
BT	1708	606	698	930	3942
BX	10259	6328	7148	9931	33666
CH	3948	5771	4109	3368	17196
CZ	110	70	70	88	338
DE	1981	2047	1683	1682	7393
ES	3345	2483	2050	2757	10635
FI	4988	4307	4302	5094	18691
FR	11453	9602	7565	9133	37753
GR	71	65	42	63	241
HR	1534	977	1002	1500	5013
HU	52	66	60	53	231
IE	123	74	146	193	536
IT	5432	6829	5045	4524	21830
NL	39	25	22	41	127
PL	773	547	566	672	2558
PT	1567	942	1075	1583	5167
RO	4154	4046	3218	3201	14619
SI	1310	1406	1159	847	4722
SK	1665	1299	941	1134	5039
UA_W	51	31	24	28	134
UK	1830	850	2188	3040	7908
Total	**66495**	**59982**	**51537**	**56836**	**234850**

Table 103: Run of river hydro seasonal production (GWh) assumed for the simulations in the different countries in the EA 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	9694	11267	8186	6645	35792
BG	352	291	191	275	1109
BL	41	36	36	43	156
BT	1708	605	698	929	3940
BX	9915	6116	6909	9597	32537
CH	3948	5771	4108	3368	17195
CZ	108	70	69	87	334
DE	1972	2037	1674	1674	7357
ES	3337	2477	2045	2750	10609
FI	4985	4305	4300	5092	18682
FR	11430	9582	7549	9115	37676
GR	71	64	43	63	241
HR	1483	944	968	1450	4845
HU	52	65	60	53	230
IE	123	74	146	192	535
IT	5398	6786	5013	4495	21692
NL	38	24	22	40	124
PL	770	546	564	670	2550
PT	1558	936	1069	1574	5137
RO	4146	4037	3212	3195	14590
SI	1305	1401	1154	844	4704
SK	1664	1299	941	1134	5038
UA_W	51	31	24	28	134
UK	1824	848	2181	3031	7884
Total	**65973**	**59612**	**51162**	**56344**	**233091**

Table 104: Run of river hydro seasonal production (GWh) assumed for the simulations in the different countries in the GR-FT 2030 scenario.

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 seasonal consumption of pumped storage hydro power plants assumed for the simulations in the different countries and in the different scenarios are reported in the following Table 105.

Country	Electricity consumption [GWh]				
	Spring	Summer	Autumn	Winter	Year
BT	168	135	158	214	675
IE	124	133	135	143	535
NO	283	247	292	351	1173
SE	10	8	9	11	38
UK	241	257	261	274	1033
Rest of Europe	10524	10533	11449	11531	44037
Total	**11350**	**11313**	**12304**	**12524**	**47491**

Table 105: Pumped storage hydro seasonal consumption (GWh) assumed for the simulations in the different countries and in the different scenarios.

As for the reservoir and pumped storage hydro power plants (that we will call "dispatchable hydro"), the criteria used to determine their imposed production profile are the same reported in [23].

The generation capacity and the seasonal production of dispatchable hydro power plants assumed for the simulations in the different countries in the 2015 scenario are reported in the following Table 106.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
BT	760	118	93	112	151	474
IE	292	81	86	87	92	346
NO	30074	30072	26199	31105	37385	124761
SE	16195	17092	13547	15634	19275	65548
UK	2744	168	180	183	192	723
Rest of Europe	106201	46412	44613	35709	39039	165773
Total	**156266**	**93943**	**84718**	**82830**	**96134**	**357625**

Table 106: Dispatchable hydro generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the 2015 scenario.

As for the three 2030 scenarios, data concerning seasonal production are reported in the folowing tables.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	5203	6049	4396	3565	19213
BG	1523	1256	814	1193	4786
BL	686	608	611	716	2621
BT	139	109	132	176	556
BX	8295	4148	5810	9152	27405
CH	4894	7160	5098	4174	21326
CZ	1030	669	651	811	3161
DE	5477	5651	4654	4647	20429
ES	6524	4837	3997	5369	20727
FR	11316	9484	7474	9020	37294
GR	1773	1590	1060	1594	6017
HR	3073	1957	1993	3003	10026
IE	116	125	127	133	501
IT	8456	10631	7855	7037	33979
NO	33326	29033	34469	41429	138257
PL	638	452	462	555	2107
PT	1220	734	834	1231	4019
RO	4565	4445	3533	3518	16061
SE	24027	19045	21977	27096	92145
SI	159	171	138	100	568
SK	563	442	318	384	1707
UK	438	469	475	500	1882
Total	**123441**	**109065**	**106878**	**125403**	**464787**

Table 107: Dispatchable hydro seasonal production (GWh) assumed for the simulations in the different countries in the MT 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	5187	6031	4382	3555	19155
BG	1560	1286	834	1223	4903
BL	698	619	622	728	2667
BT	143	112	136	182	573
BX	8272	4136	5794	9126	27328
CH	4894	7160	5098	4174	21326
CZ	1047	679	661	824	3211
DE	5617	5796	4774	4766	20953
ES	6671	4947	4087	5490	21195
FR	10985	9207	7255	8757	36204
GR	1851	1659	1107	1663	6280
HR	3065	1952	1987	2994	9998
IE	118	126	128	135	507
IT	9232	11607	8576	7684	37099
NO	33326	29033	34469	41429	138257
PL	660	467	478	574	2179
PT	1243	749	850	1255	4097
RO	4296	4184	3326	3311	15117
SE	23899	18943	21861	26952	91655
SI	149	160	130	94	533
SK	563	443	318	384	1708
UK	451	483	489	514	1937
Total	**123927**	**109779**	**107362**	**125814**	**466882**

Table 108: Dispatchable hydro seasonal production (GWh) assumed for the simulations in the different countries in the EA 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	5182	6024	4378	3551	19135
BG	1540	1270	823	1207	4840
BL	694	616	619	724	2653
BT	143	112	136	182	573
BX	7995	3998	5599	8820	26412
CH	4894	7160	5097	4174	21325
CZ	1034	671	653	814	3172
DE	5590	5768	4751	4743	20852
ES	6655	4935	4077	5477	21144
FR	10962	9188	7240	8739	36129
GR	1845	1654	1104	1659	6262
HR	2962	1886	1921	2894	9663
IE	117	126	128	134	505
IT	9174	11533	8521	7635	36863
NO	33324	29031	34468	41426	138249
PL	658	466	477	572	2173
PT	1236	745	845	1248	4074
RO	4288	4176	3319	3305	15088
SE	23937	18974	21896	26995	91802
SI	148	160	130	93	531
SK	563	442	318	384	1707
UK	449	481	488	513	1931
Total	**123390**	**109416**	**106988**	**125289**	**465083**

Table 109: Dispatchable hydro seasonal production (GWh) assumed for the simulations in the different countries in the GR-FT 2030 scenario.

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.

Wind power plants

As for wind power plants, data have been collected concerning the equivalent full-load annual hours and the seasonal distribution of production (see [24]÷[27], [33], [34]). The 2015 annual electricity production has therefore been 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.

As for year 2030, data concerning the annual electricity production have been taken from the results of the three POLES scenarios (MT, EA and GR-FT), while the seasonal distribution has been assumed equal to the 2015 one.

The generation capacity and the seasonal production of wind power plants assumed for the simulations in the different countries and in the different scenarios are reported in the following tables.

Country	**Net generation capacity [MW]**	**Electricity production [GWh]**				
		Spring	**Summer**	**Autumn**	**Winter**	**Year**
BT	995	452	452	448	443	1795
DE	41032	16774	11010	16638	24164	68586
FI	183	67	58	101	111	337
IE	3282	1483	1185	1757	1949	6374
IT	7112	4487	2289	2832	3773	13381
NO	555	226	180	390	401	1197
SE	3822	1420	1484	2374	2612	7890
UK	14723	8901	7399	11518	12016	39834
Rest of Europe	55502	32526	30596	31655	33966	128743
Total	**127206**	**66336**	**54653**	**67713**	**79435**	**268137**

Table 110: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the 2015 scenario.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	4617	1849	1849	1828	1808	7334
BG	3460	2233	1674	2512	2512	8931
BL	6979	4174	4174	4129	4084	16561
BT	2907	1433	1433	1417	1401	5684
BX	58	36	36	35	35	142
CH	273	110	110	109	108	437
CZ	5031	1961	1961	1940	1918	7780
DE	45354	24521	16095	24322	35324	100262
ES	25675	14815	14815	14655	14493	58778
FI	7313	3108	2689	4721	5200	15718
FR	31518	17159	17159	16972	16785	68075
GR	5684	3520	3520	3482	3444	13966
HR	206	142	101	121	141	505
HU	2776	1121	1121	1108	1096	4446
IE	2869	1688	1349	1999	2218	7254
IT	25202	14590	7443	9210	12268	43511
NL	8389	4962	3383	4517	7484	20346
NO	1635	716	571	1237	1271	3795
PL	16005	9029	9029	8931	8832	35821
PT	4746	2405	1821	2173	2621	9020
RO	5377	3378	3118	3118	3378	12992
SE	11425	4547	4750	7600	8364	25261
SI	667	387	290	387	483	1547
SK	2090	839	839	831	821	3330
UK	32642	18020	14979	23319	24327	80645
Total	**252898**	**136743**	**114309**	**140673**	**160416**	**552141**

Table 111: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the MT 2030 scenario.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	3811	1487	1487	1470	1454	5898
BG	4126	2462	1846	2769	2769	9846
BL	6815	4103	4103	4059	4014	16279
BT	5188	2615	2615	2586	2557	10373
BX	53	33	33	33	32	131
CH	323	130	130	129	128	517
CZ	6714	2559	2559	2531	2504	10153
DE	62502	35647	23397	35358	51352	145754
ES	40391	23790	23790	23532	23273	94385
FI	9046	3773	3265	5731	6312	19081
FR	50342	26150	26150	25865	25581	103746
GR	9063	5451	5451	5392	5332	21626
HR	188	130	93	111	130	464
HU	4603	1831	1831	1810	1791	7263
IE	4154	2361	1887	2797	3103	10148
IT	30034	17686	9022	11164	14871	52743
NL	6919	4032	2749	3670	6081	16532
NO	1940	929	741	1606	1649	4925
PL	25406	13258	13258	13114	12970	52600
PT	8765	4601	3483	4155	5012	17251
RO	7458	4777	4410	4409	4777	18373
SE	12027	4362	4557	7292	8025	24236
SI	978	560	420	560	701	2241
SK	3426	1331	1331	1317	1302	5281
UK	42438	24491	20358	31694	33065	109608
Total	**346710**	**188549**	**158966**	**193154**	**218785**	**759454**

Table 112: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the EA 2030 scenario.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	3298	1302	1302	1289	1274	5167
BG	3270	2012	1509	2264	2263	8048
BL	5846	3315	3315	3280	3243	13153
BT	3135	1590	1590	1573	1556	6309
BX	67	41	41	41	41	164
CH	243	98	98	97	96	389
CZ	4753	1860	1860	1840	1820	7380
DE	44914	24123	15833	23927	34751	98634
ES	28292	16400	16400	16222	16044	65066
FI	6251	2652	2295	4029	4436	13412
FR	27888	14527	14527	14369	14212	57635
GR	5392	3216	3216	3181	3147	12760
HR	238	164	117	141	164	586
HU	2852	1151	1151	1139	1126	4567
IE	2748	1602	1280	1898	2105	6885
IT	24662	14225	7257	8979	11961	42422
NL	6474	3687	2514	3356	5561	15118
NO	1460	710	566	1226	1259	3761
PL	16643	9092	9092	8994	8895	36073
PT	5916	3107	2352	2806	3385	11650
RO	5562	3557	3284	3284	3557	13682
SE	12414	4671	4880	7809	8593	25953
SI	622	358	269	358	447	1432
SK	2294	915	915	904	895	3629
UK	30074	16251	13508	21029	21939	72727
Total	**245308**	**113102**	**94479**	**111744**	**129489**	**448814**

Table 113: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the GR-FT 2030 scenario.

Photovoltaic solar power plants

As for photovoltaic solar power plants, in the countries not considered in [23] the estimated installed generation capacity in 2015 can be considered basically negligible.

As for year 2030, installed capacity data have been taken from the results of the three POLES scenarios (MT, EA and GR-FT).

Data concerning the annual / monthly production of each installed kW at optimal inclination have been taken from the *Photovoltaic Geographical Information System* (PVGIS) of the JRC - *Joint Research Centre [12]*), while the hourly generation profiles have been built on the basis of the average daily hours of light in each month taken from [35].

The generation capacity and the annual production of photovoltaic solar power plants assumed for the simulations in the different countries in the 2030 scenarios are reported in the following tables.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	969	968	966
BG	133	151	157
BL	623	560	571
BT	60	57	56
BX	48	38	39
CH	296	268	302
CZ	1443	1444	1444
DE	11217	11209	11213
ES	10973	9789	10012
FI	132	172	175
FR	16864	16864	16864
GR	3689	3683	3682
HR	14	11	12
HU	78	80	80
IE	67	63	64
IT	13875	13875	13875
NL	190	232	215
PL	30	31	31
PT	1578	1574	1574
RO	50	98	100
SE	1262	712	868
SI	802	808	818
SK	427	348	351
UK	107	119	116
Total	**64927**	**63154**	**63585**

Table 114: Photovoltaic solar generation capacity (MW) assumed for the simulations in the different countries in the 2030 scenarios.

Country	Electricity production [GWh]		
	MT	EA	GR-FT
AT	1151	1147	1143
BG	383	436	451
BL	581	523	532
BT	173	164	160
BX	137	109	111
CH	753	671	767
CZ	1709	1712	1712
DE	11209	11201	11205
ES	21884	18472	19114
FI	360	472	482
FR	22004	22005	22005
GR	5442	5425	5424
HR	40	32	34
HU	224	231	230
IE	193	182	183
IT	19325	19325	19325
NL	173	211	195
PL	86	87	87
PT	2333	2324	2323
RO	142	283	287
SE	3579	1993	2442
SI	1589	1609	1630
SK	594	502	506
UK	104	115	112
Total	**94168**	**89231**	**90460**

Table 115: Photovoltaic solar annual production (GWh) assumed for the simulations in the different countries in the 2030 scenarios.

Other RES + waste

To estimate the electricity production of other renewable energy sources (biomass, biogas, geothermal, etc.) and of waste non-CHP power plants a value of 4500 equivalent full-load annual hours has been taken into account[33]. Moreover, a flat generation profile has been assumed.

Data for the 2015 scenario have been taken from [24] ÷ [27] and are reported in the following Table 115.

As for year 2030, data concerning the annual electricity production have been taken from the results of the three POLES scenarios (MT, EA and GR-FT).

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

The generation capacity and the annual production of such power plants assumed for the simulations in the 2030 scenarios in the different countries are reported in the following Table 117 and Table 118.

Country	Net generation capacity [MW]	Electricity production [GWh]
DE	8400	37797
FI	201	904
IE	168	756
Rest of Europe	9568	46570
Total	**18337**	**86027**

Table 116: "Other RES + waste" non-CHP generation capacity (MW) and annual production (GWh) assumed for the simulations in the different countries in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	861	1256	1203
BG	250	3028	3239
BL	657	956	1392
BT	371	766	1237
CH	418	373	414
CZ	965	1971	2159
DE	5884	16302	17473
ES	526	3064	4825
FI	3482	4382	4471
FR	1933	3624	4084
GR	100	481	510
HR	71	62	72
HU	977	2128	2370
IE	542	1351	890
IT	2488	3328	3841
NL	4957	9544	9489
NO	199	178	198
PL	1726	6327	8380
PT	283	698	1137
RO	497	1251	1857
SE	4905	5756	6705
SI	47	44	83
SK	563	1554	1777
UA_W	29	26	39
UK	2389	3684	3471
Total	**35120**	**72134**	**81316**

Table 117: "Other RES + waste" generation capacity (MW) assumed for the simulations in the different countries in the 2030 scenarios.

Country	Electricity production [GWh]		
	MT	EA	GR-FT
AT	1858	3083	3573
BG	1856	10262	11524
BL	3331	5333	7482
BT	2303	3474	4469
CH	1623	1488	1534
CZ	3827	12291	13403
DE	43146	118630	127180
ES	1315	8369	12342
FI	17556	21698	22189
FR	9385	9352	13678
GR	711	2879	3287
HR	402	338	403
HU	4011	6328	7536
IE	778	3955	2225
IT	15977	21820	27355
NL	12674	41442	44223
NO	773	710	734
PL	13441	37488	45112
PT	1862	3901	5814
RO	3217	8640	10894
SE	7809	11341	9608
SI	193	250	442
SK	3636	4096	3853
UA_W	229	205	307
UK	9621	13555	20408
Total	**161534**	**350928**	**399575**

Table 118: "Other RES + waste" annual production (GWh) assumed for the simulations in the different countries in the 2030 scenarios.

Other scenario assumptions

Concerning year 2015, in most cases the other main scenario assumptions have been derived from the POLES scenario *"GR-FT Global Regime with Full Trade"*, since in that year 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: for this reason, for year 2030, data specific for each POLES scenario have been taken into account, as reported in the following.

Fuel prices

Oil, coal and gas prices have been directly taken from the POLES scenarios, while 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
Coal CCS[34]	2.408

Table 119: Fuel prices assumed for year 2015 in the simulations.

[34] CO_2 transportation and storage costs, estimated equal to 5 €/tCO_2, are here included in the fuel price proportionally to its carbon content: for coal it corresponds to about 0.472 €/GJ.

Fuel	Price [€/GJ]		
	MT	EA	GR-FT
Coal	2.223	2.197	2.122
Lignite	1.001	0.989	0.955
Gas	6.340	6.248	5.655
Fuel Oil	11.800	11.303	10.398
Nuclear	0.485	0.485	0.508
Coal CCS[34]	2.696	2.669	2.595
Gas CCS[35]	6.812	6.721	6.127

Table 120: Fuel prices assumed for year 2030 in the simulations.

CO_2 emissions value

The CO_2 emissions value for year 2015 is 13.25 €/tCO_2, as in the GR-FT scenario.
In the different 2030 scenarios CO_2 emissions values are the ones reported in Table 121.

	MT	EA	GR-FT
CO_2 emissions value [€/tCO_2]	24.26	90.28	63.26

Table 121: CO_2 emissions values in the different 2030 scenarios.

Electricity demand

The annual values of the 2015 electrical load (final consumptions plus network losses; pumped storage consumption not included: see paragraph 0) have been taken from the GR-FT scenario, except for Norway, whose data are not detailed in POLES. Since the overall 2015 European load is quite similar to the 2008 one, Norway's 2015 load has been assumed equal to the 2008 one.
The considered annual load values for the 2015 scenario are reported in the following Table 122.

[35] CO_2 transportation and storage costs, estimated equal to 5 €/tCO_2, are here included in the fuel price proportionally to its carbon content: for natural gas it corresponds to about 0.279 €/GJ.

Country	Final consumption + network losses [GWh]		
	2008	2015	∆%
BT	25669	25226	-1.73
FI	85223	86121	1.05
IE	28903	27834	-3.70
NO	125879	125879	0.00
SE	156228	149294	-4.44
UK	340022	366114	7.67
Rest of Europe	2614046	2588412	-0.98
Total	**3375970**	**3368880**	**-0.21**

Table 122: 2008 and 2015 annual electrical load values for the considered countries.

As for year 2030, data have been taken from the three POLES scenarios or, in case of countries whose data are aggregated in POLES, data have been extrapolated on the basis of the share that each country had in 2008 in the aggregate of countries considered by POLES.

The considered annual load values for the 2030 scenarios are reported in the following Table 123.

Country	Final consumption + network losses [GWh]		
	MT	EA	GR-FT
AT	76764	72905	73371
BG	42760	38702	39876
BL	119525	109452	111057
BT	31730	29385	29323
BX	100443	96009	91548
CH	67341	65924	65761
CZ	87272	80683	81285
DE	721219	658956	668815
ES	391627	381346	375822
FI	105162	102066	102570
FR	629152	604302	602042
GR	85628	77650	77640
HR	25140	24031	22914
HU	51525	48376	48221
IE	36543	34924	35010
IT	366876	362064	362488
NL	158043	151753	151415
NO	134722	131887	131561
PL	188913	173414	173210
PT	72476	66778	67435
RO	65510	62999	63357
SE	171391	165121	164555
SI	18894	17972	17893
SK	31804	29570	29604
UA_W	6161	6148	5944
UK	483641	455429	457234
Total	**4270262**	**4047846**	**4049951**

Table 123: 2030 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],[17]), then it has been scaled according to the 2015 or 2030 / 2008 annual load ratio. The last step has been to align the working days and the holidays of 2015 or 2030 with those of 2008.
Load profiles have been either taken or estimated using data from [36]÷[43].

VOLL (Value Of Lost Load)

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 [34], 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 16.36 €/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.

Costs of cross-border network expansion

As far as network expansion is concerned, we used the average cost data considered within the context of the FP7 REALISEGRID project (see [9]), based on publicly available sources and information from TSOs and from manufacturers. Of course, it must be taken into account that cost values may vary depending on different parameters, such as line characteristics (such as type, length, power rating, voltage level) as well as on several local factors, like manpower costs, environmental constraints, geographical conditions, etc.
In particular, the main assumptions are the following:

- ***HVAC overhead lines***
  - average line length: 80 km
  - average investment cost (CAPEX): 50 k€/MW
  - average local compensation costs: 15% CAPEX una tantum
  - average O&M costs: 5% CAPEX yearly
  - interest rate: 8%
  - operating life: 40 years
  - ⇨ annualized cost: **7322 €/MW**
- ***HVDC cables***
  - average line length: 130 km
  - average investment cost – cable: 220 k€/MW
  - average investment cost – converters: 140 k€/MW
  - average local compensation costs: no costs
  - average O&M costs: 5% CAPEX yearly
  - interest rate: 8%
  - operating life: 40 years
  - ⇨ annualized cost: **48190 €/MW**

Results of the simulations

As above mentioned, we compared scenarios characterized by the developments of cross-border interconnections specified in chapter 0, mainly proposed by the different European TSOs (that we will call *"proposed expansion"*), with the optimal developments determined by MTSIM (that we will call *"optimal expansion"*) in the different 2015 and 2030 scenarios.
Of course, the decision to build a cross-border transmission line is based on a detailed analysis of several factors that are not taken into account in the simulations carried out in the present study, nevertheless, even if approximated, the results reported in the following can provide an interesting insight on the optimality (in terms of costs) level of the European cross-border transmission network.
In particular, in this study MTSIM has been used to simulate the optimal behavior of the modeled European power system, having as objective function the cost (fuel, CO_2 allowances and network expansion) minimization. No market power exercise has been simulated, in order to focus on the "natural" best response of the modeled power system.

As far as security of supply is concerned, the main general result of the simulations is that in no one of the considered scenarios there is Energy Not Supplied (ENS): this means that the modelled generation / transmission system is always able to supply the load.

In the following, for each considered scenario, we report the main results concerning:

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

2015 scenario

Impact on congestion

In the 2015 scenario, the simulation determined the optimal expansion (w.r.t. the *“proposed expansion”*) of cross-border transmission network reported in the following Table 124.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC values (B→A) [MW]
ES→FR	6351	8951	8951
FR→DE	4713	7613	7763
DE→NO	1000	2600	2600
DE→SE	1000	2890	2830
FR→UK	1000	3000	3000
CH→AT	744	1944	1944
BG→GR	689	2189	2089
BX→RO	621	921	1271
FI→NO	469	569	569
DE→PL	456	2056	1956
SK→UA_W	345	745	745
IT→SI	275	925	925
RO→UA_W	266	666	666
HU→UA_W	222	872	872
CH→DE	90	3290	1590
HU→BX	39	639	639

Table 124: Optimal expansion values (additional capacity) and corresponding new NTC values (MW) in the 2015 scenario.

In Figure 27, Figure 28, Figure 29 and Figure 30 a comparison between the percentages of hours with congestion (i.e. when the power flow saturates the interconnection transmission capacity) in the different cross-border interconnections in July and in December 2015 with the “proposed expansion” and with the “optimal expansion” is reported.

In the July 2015 “optimal expansion” scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.

In the December 2015 “optimal expansion” scenario, congestion is still reduced, even if in a less significant way than in July 2015.

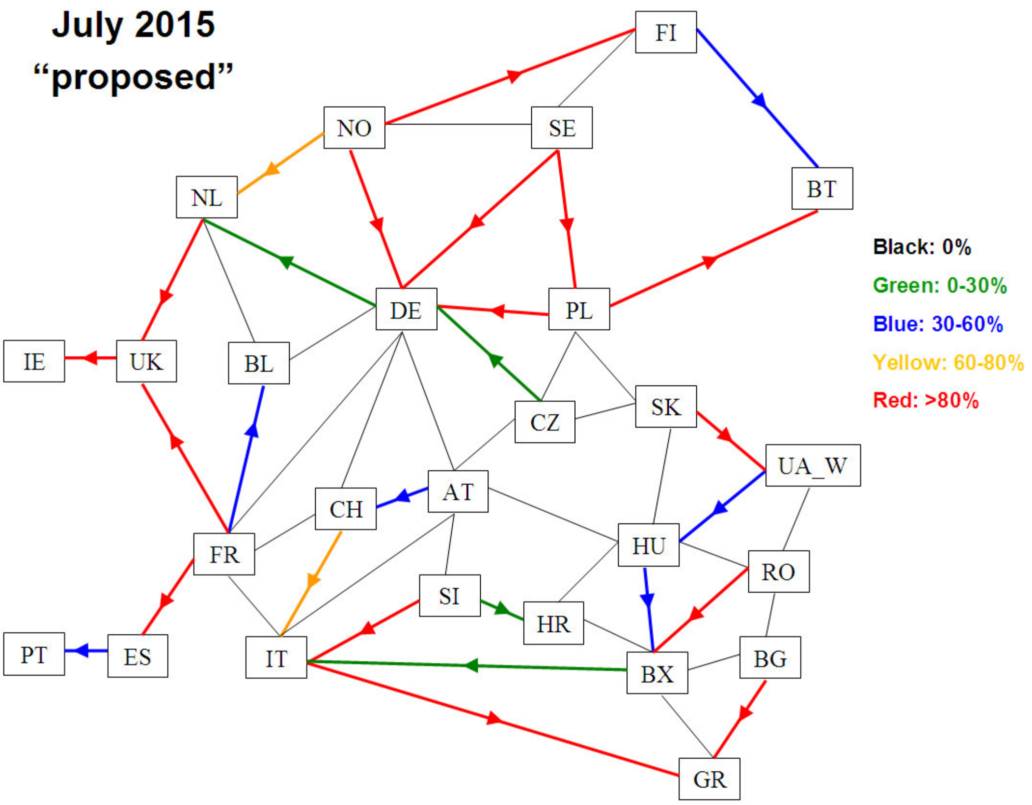

Figure 27: Percentages of hours with congestion in July 2015 with the "proposed expansion".

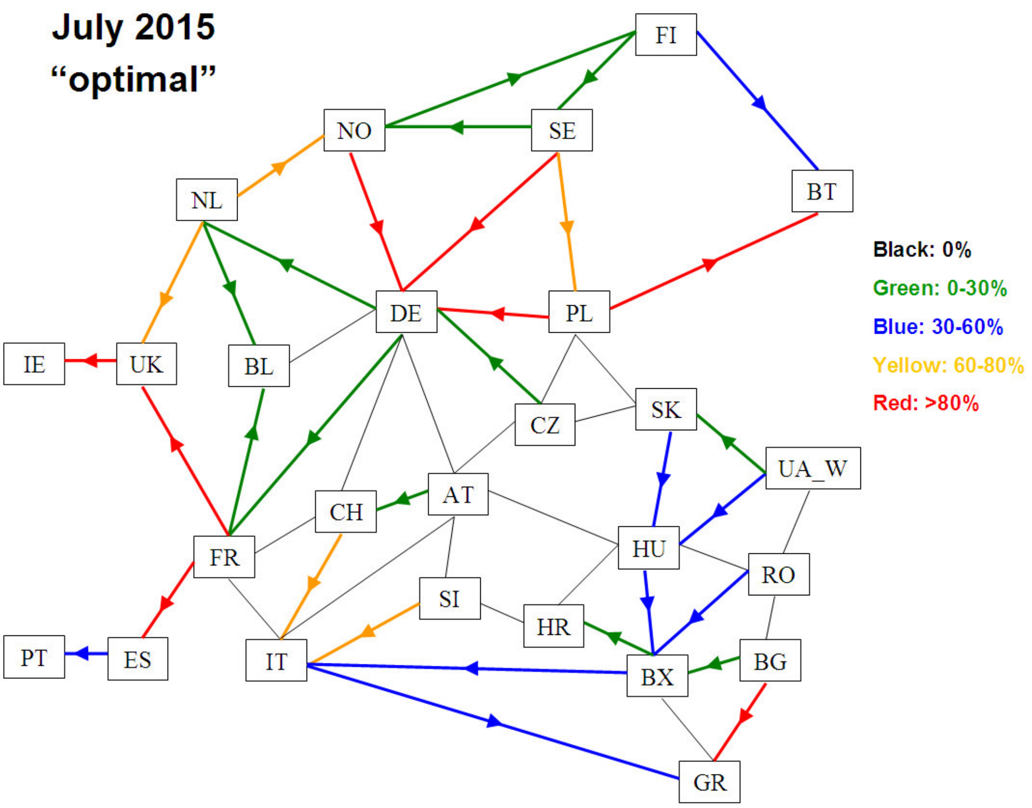

Figure 28: Percentages of hours with congestion in July 2015 with the "optimal expansion".

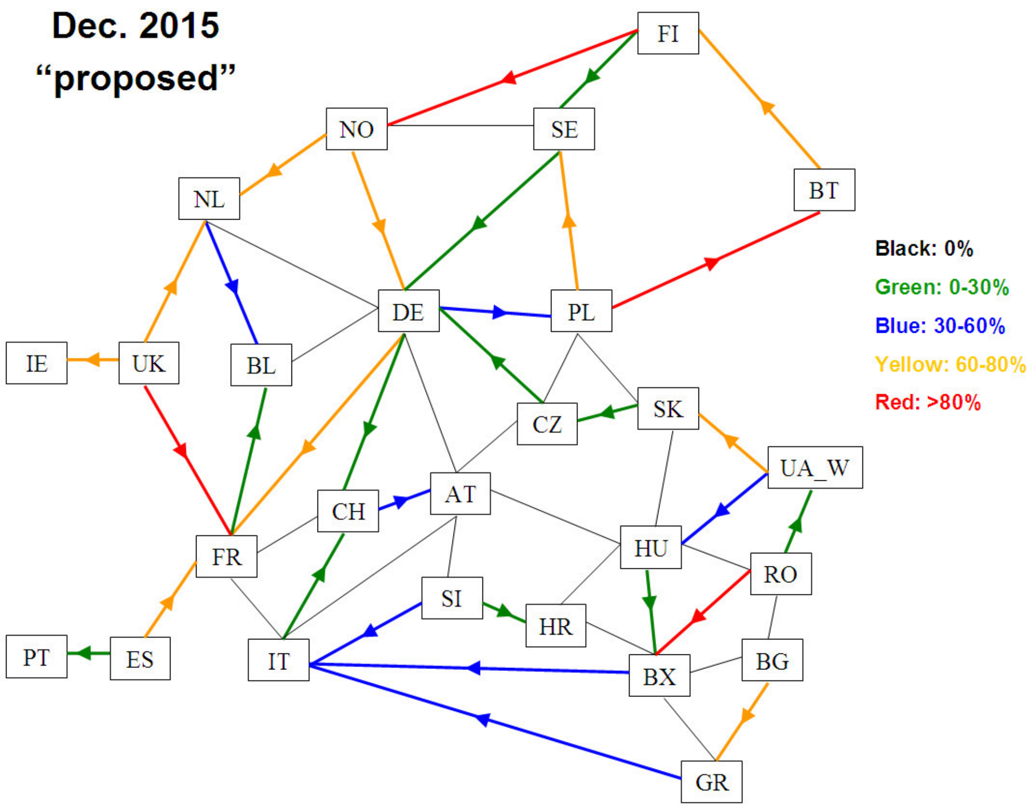

Figure 29: Percentages of hours with congestion in December 2015 with the "proposed expansion".

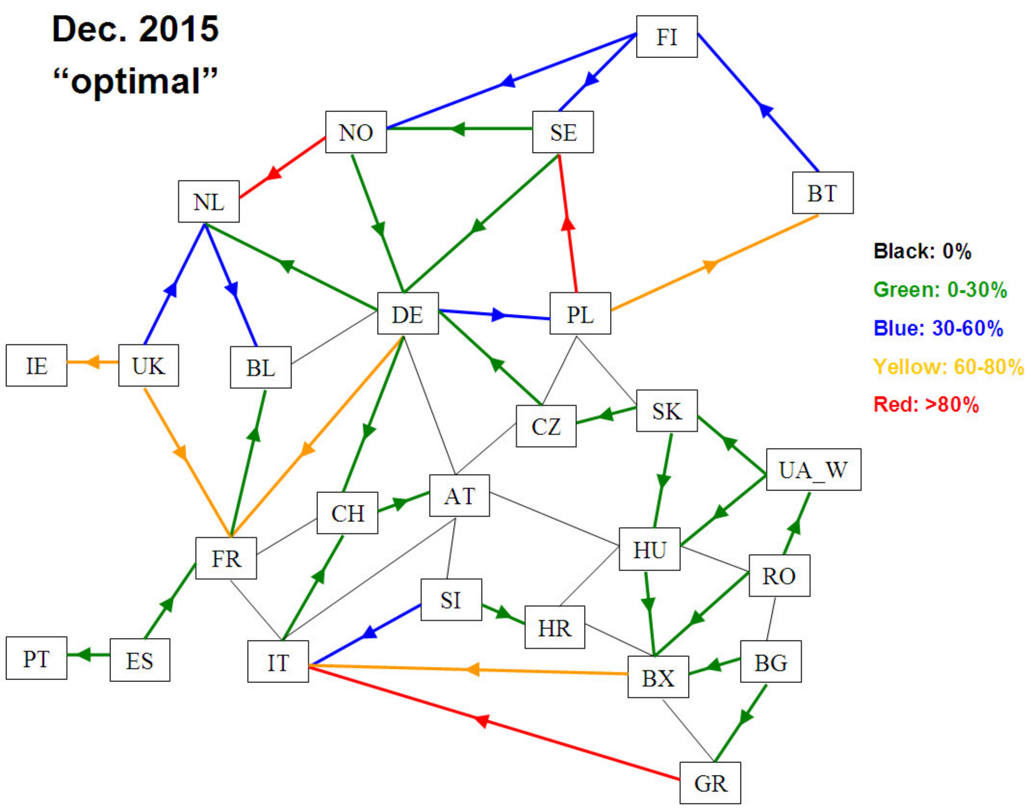

Figure 30: Percentages of hours with congestion in December 2015 with the "optimal expansion".

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

France (FR) – Spain (ES)

- *"proposed expansion"*: throughout the year, the percentage of congested hours is almost always over 80% and from May to August the interconnection is completely saturated;
- *"optimal expansion"*: congestion significantly decreases and no month shows a complete saturation; July is the only month that remains still critical, with a percentage over 80%.

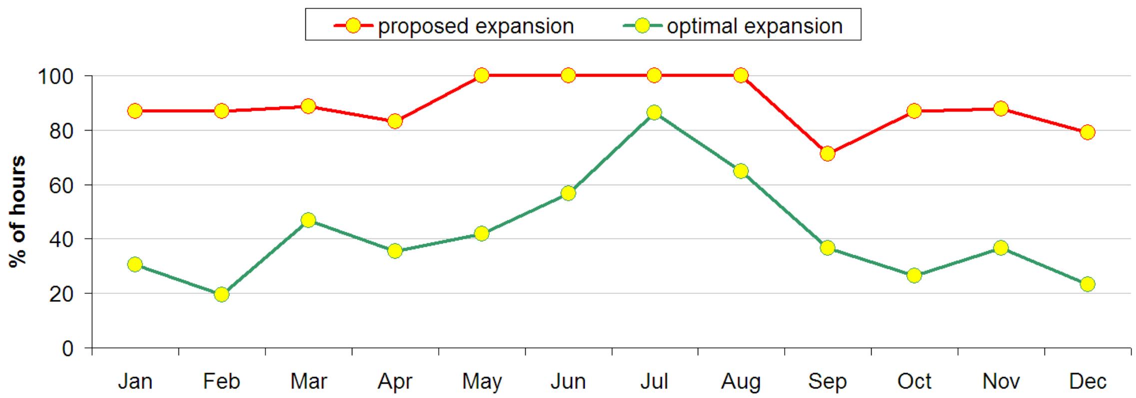

Figure 31: Percentages of congested hours in the France – Spain interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Poland (PL) – Germany and Denmark West (DE)

- *"proposed expansion"*: the most critical period is summer (from May to August), when the interconnection is almost completely saturated;
- *"optimal expansion"*: congestion decreases significantly in summer, except July, whereas in winter the situation is similar to the "proposed expansion".

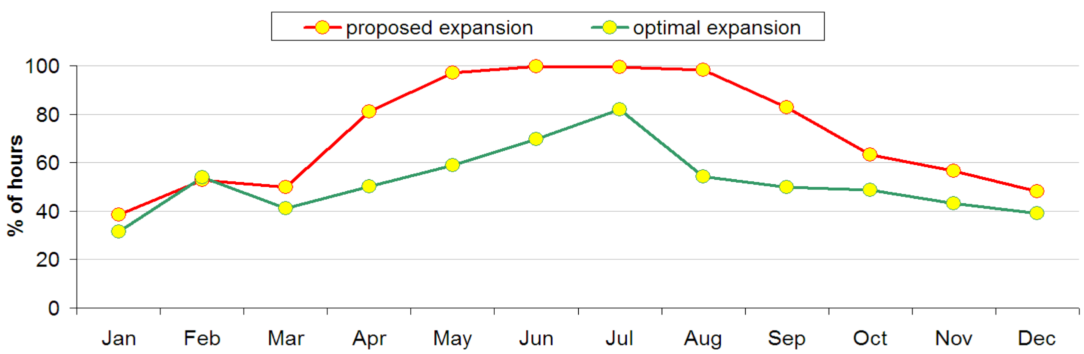

Figure 32: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Romania (RO) – Balkan countries (BX)

- *"proposed expansion"*: the percentage of congested hours is quite high, being near or over 80% from March to December;
- *"optimal expansion"*: congestion decreases dramatically, so that the highest values reach about 50% only in June and in July.

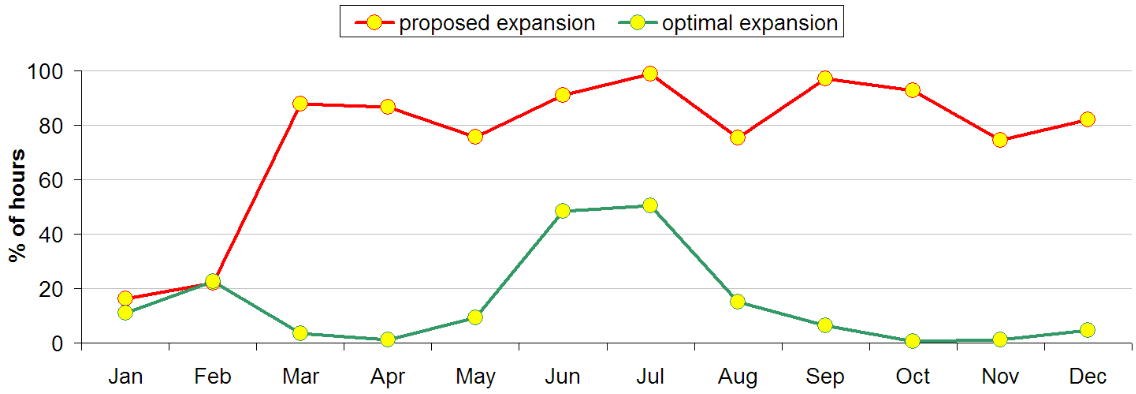

Figure 33: Percentages of congested hours in the Romania – Balkan countries interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Bulgaria (BG) – Greece (GR)

- *"proposed expansion"*: the interconnection is highly congested in summer, with a complete saturation in July;
- *"optimal expansion"*: congestion decreases, but less significantly during the summer months; in July the situation remains critical reaching a value close to 90%.

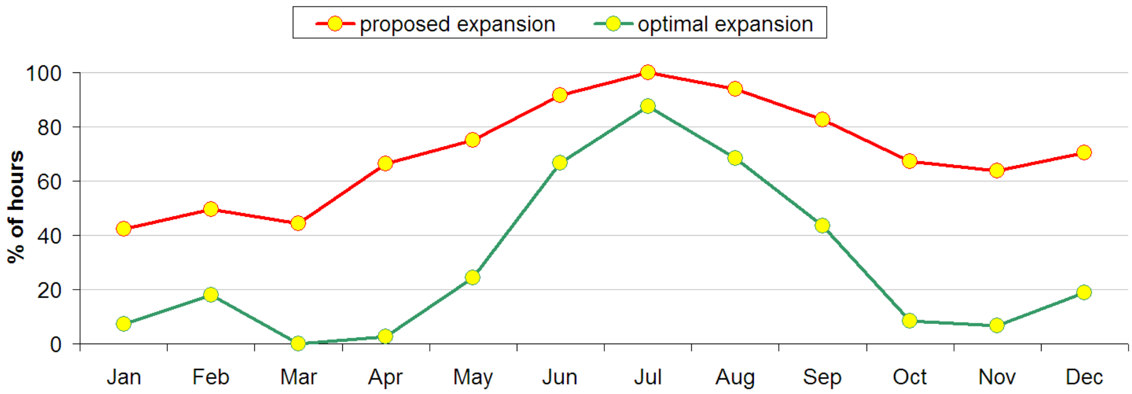

Figure 34: Percentages of congested hours in the Bulgaria – Greece interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Norway (NO) – Finland (FI)

- *"proposed expansion"*: congestion situation is very critical throughout the entire year, being almost always over 80%, with a complete saturation in July;
- *"optimal expansion"*: congestion situation improves significantly, especially during spring and summer.

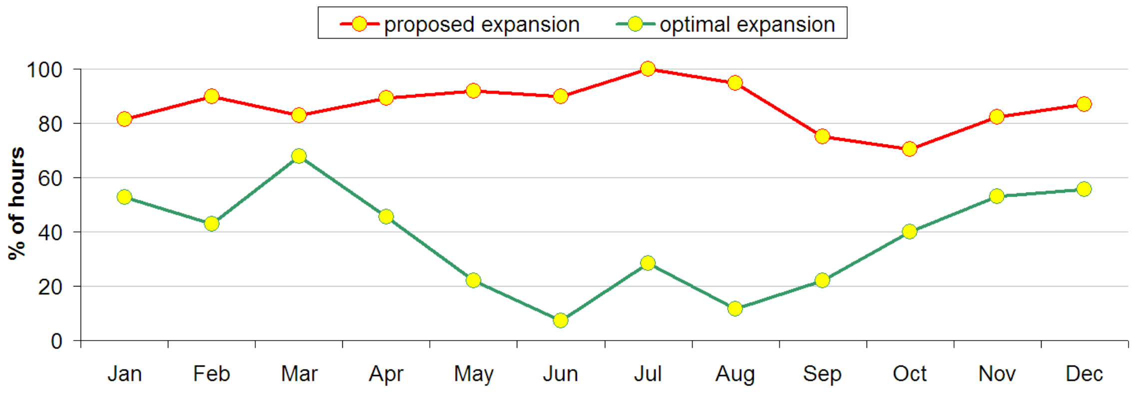

Figure 35: Percentages of congested hours in the Norway – Finland interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

France (FR) – United Kingdom (UK)

- *"proposed expansion"*: congestion situation remains critical throughout the entire year and, in particular, during the summer period, when a complete saturation occurs from May to August;
- *"optimal expansion"*: congestion situation improves slightly during the summer period, even though, throughout the year, the percentage remains always above 65%.

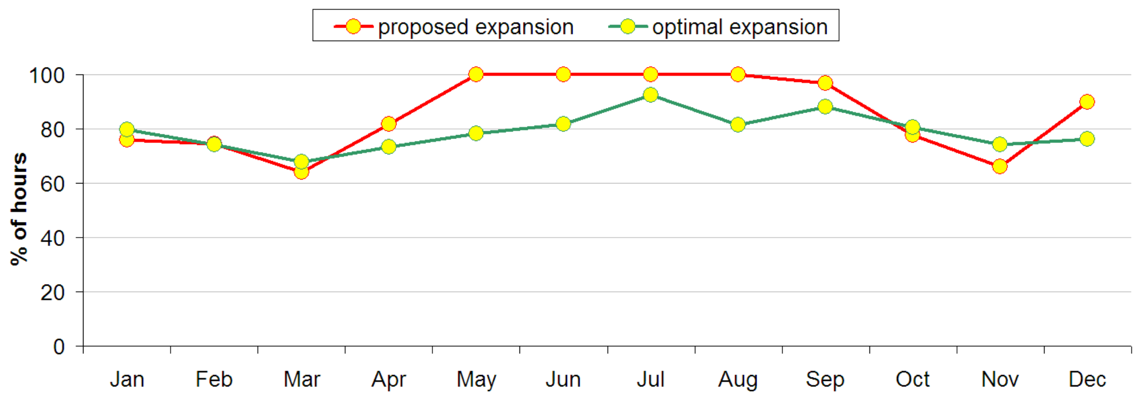

Figure 36: Percentages of congested hours in the France – United Kingdom interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Norway (NO) – Germany and Denmark West (DE)

- *"proposed expansion"*: congestion situation remains very critical throughout the summer period between June and September, with an almost complete saturation;
- *"optimal expansion"*: congestion situation improves throughout the year, but it remains relatively critical in June, July and August, when the percentage is always over 80%.

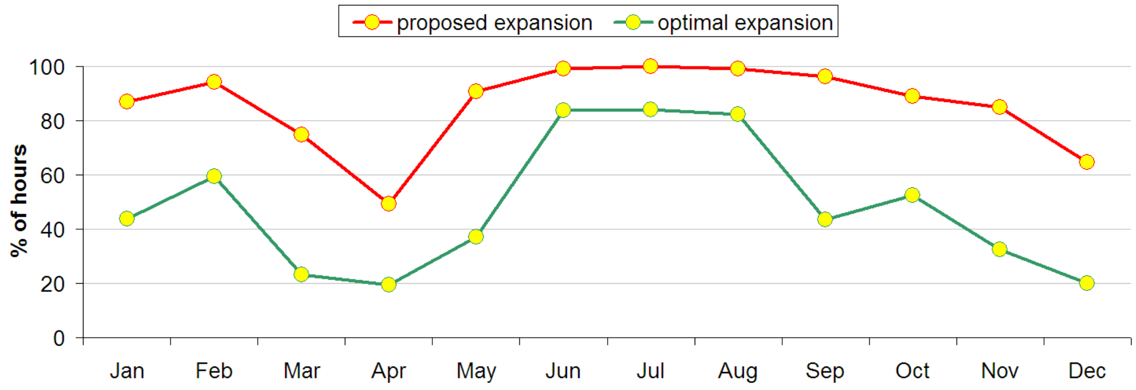

Figure 37: Percentages of congested hours in the Norway – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Sweden and Denmark East (SE) – Germany and Denmark West (DE)

- *"proposed expansion"*: congestion situation is very critical during the summer period between May and August, since the percentage remains above 95% and it reaches a full saturation in July;
- *"optimal expansion"*: congestion situation improves slightly, but it remains critical during the period between May and August, with values over 90%.

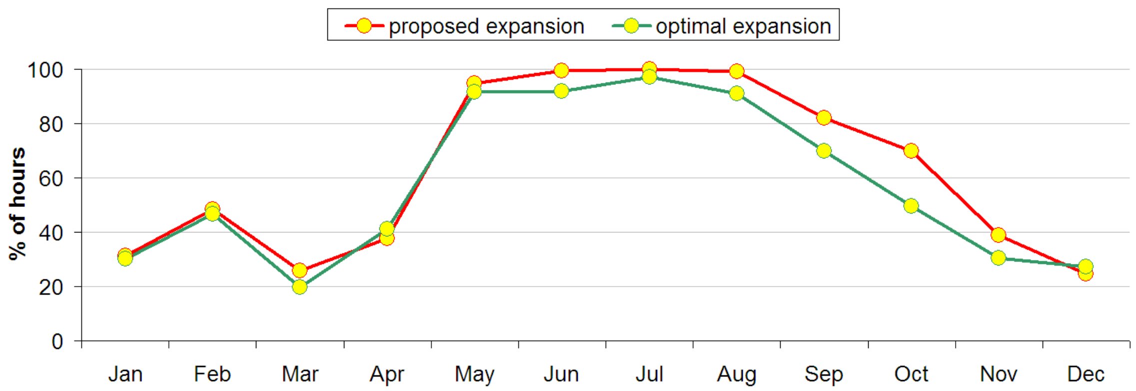

Figure 38: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Sweden and Denmark East (SE) – Poland (PL)

- *"proposed expansion"*: congestions situation is relatively critical throughout the entire year and, in particular, in July when a complete saturation occurs;
- *"optimal expansion"*: the redistribution of power flows in the optimal expansion scenario improves congestion situation during the summer period between May and August, while it worsen during the rest of the year.

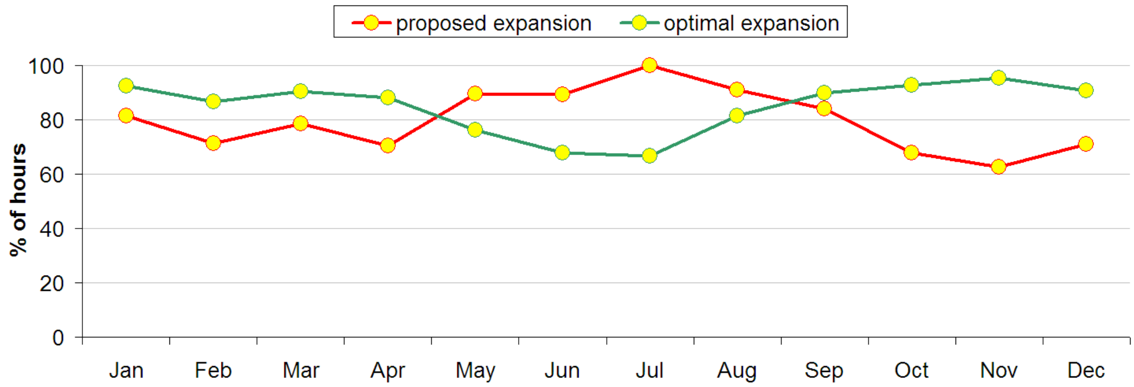

Figure 39: Percentages of congested hours in the Sweden and Denmark East – Poland interconnection in the "proposed expansion" and in the "optimal expansion" 2015 scenarios.

Impact on electricity prices

In a zonal electricity market, like the one modeled in the present study, congestion causes price differentiation between the zones. Therefore, it is interesting to see how electricity prices (or, better, marginal generation costs, in our case) vary when cross-border network is "optimally" expanded, w.r.t. the "proposed expansion" scenario.

In this way it is possible to determine "winners" and "losers", i.e countries where the optimal expansion causes, respectively, a decrease or an increase of electricity prices.

In the following Figure 40 "winners" are shown in green, and "losers" are shown in red. The reported numerical values are the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.

It can be noted that the main "winners" in this scenario are Poland, Portugal and Spain, while the main "losers" are Sweden and Denmark East, France, Austria, Romania, Bulgaria and Slovenia.

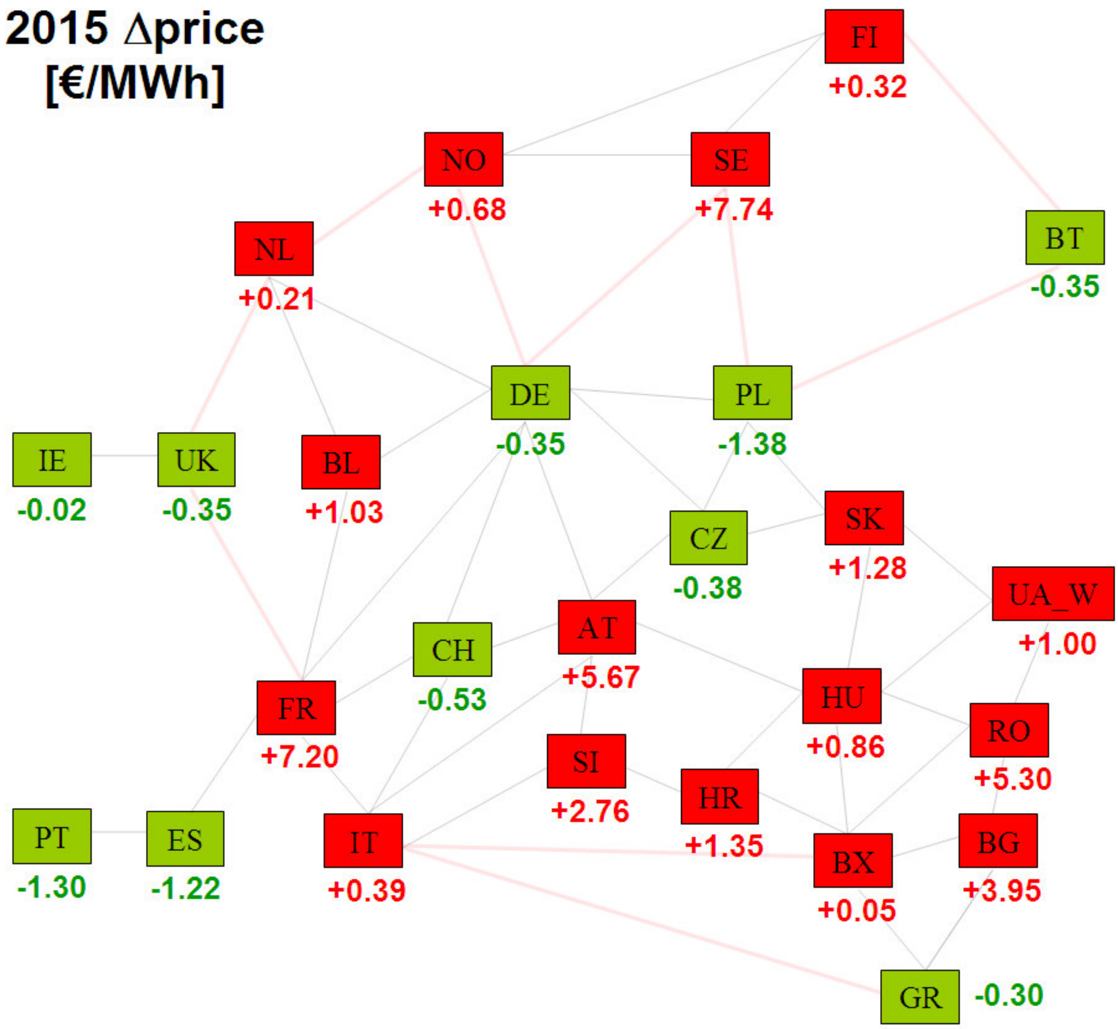

Figure 40: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2015 scenarios.

Impact on fuel consumption

In the following Table 125, a comparison between electricity production by different fuels of non-CHP power plants in the "proposed expansion" and in the "optimal expansion" scenarios is reported.

The consequence of the "optimal expansion" (that reduces network constraints) is an increase of production by cheaper base-load power plants (nuclear, hard coal and lignite) at the expense of mid-merit / peak-load natural gas fired power plants.

In Table 126 the corresponding data in terms of fuel consumption are reported: the greater use of less efficient generation technologies slightly increases total fuel consumption.

Fuel	"proposed expansion" [GWh]	"optimal expansion" [GWh]	Δ [GWh]	Δ%
Nuclear	915363	929249	13886	1.5
Hard coal	609131	616591	7460	1.2
Lignite	277575	280048	2473	0.9
Natural gas	216890	193070	-23820	-11.0
Fuel oil	-	-	-	-
Coal CCS	25017	25017	-	-

Table 125: Comparison between electricity generation by different fuels of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2015 scenarios (GWh).

Fuel	"proposed expansion" [PJ]	"optimal expansion" [PJ]	Δ [PJ]	Δ%
Nuclear	9482.9	9625.7	142.8	1.5
Hard coal	6246.9	6323.9	77	1.2
Lignite	2865.9	2891.8	25.9	0.9
Natural gas	1553.4	1389.1	-164.3	-10.6
Fuel oil	-	-	-	-
Coal CCS	200.1	200.1	-	-
Total	**20349.2**	**20430.6**	**81.4**	**0.4**

Table 126: Comparison between fuel consumption of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2015 scenarios (PJ).

Impact on CO_2 emissions

In the following Table 127 a comparison between CO_2 emissions by different fuels of non-CHP power plants in the "proposed expansion" and in the "optimal expansion" scenarios is reported.
Due to substitution of natural gas fired generation with less efficient and more emissive (apart from nuclear) power plants, overall CO_2 emissions slightly increase, by about **660 ktCO_2**.

Fuel	"proposed expansion" [$MtCO_2$]	"optimal expansion" [$MtCO_2$]	Δ [$MtCO_2$]	Δ%
Hard coal	587.21	594.45	7.24	1.2
Lignite	289.68	292.30	2.62	0.9
Natural gas	86.99	77.79	-9.20	-10.6
Fuel oil	-	-	-	-
Coal CCS	1.88	1.88	-	-
Total	**965.76**	**966.42**	**0.66**	**0.07**

Table 127: Comparison between CO_2 emissions of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2015 scenarios ($MtCO_2$).

Impact on costs

In the following Table 128 a comparison between each cost item of the modelled power system in the "proposed expansion" and in the "optimal expansion" scenarios is reported.

It can be noted that a significant reduction of fuel costs (about 600 M€) is partially compensated especially by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **335 millions of Euros**.

Cost item	"proposed expansion" [M€]	"optimal expansion" [M€]	Δ [M€]	Δ%
Fuel consumption	27017	26416	-601	-2.2
CO_2 emissions allowances	12793	12802	9	0.1
Investments / O&M AC lines	-	112	112	-
Investments / O&M DC lines	-	145	145	-
TOTAL COSTS	**39810**	**39475**	**-335**	**-0.8**

Table 128: Comparison between costs of the modeled power system in the "proposed expansion" and in the "optimal expansion" 2015 scenarios (M€).

2030 "MT – Muddling Through" scenario

Impact on congestion

In the 2030 MT scenario, the simulation determined the optimal expansion (w.r.t. the *"proposed expansion"*) of cross-border transmission network reported in the following Table 129.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
FR→DE	5612	8512	8662
DE→PL	4501	7001	6901
SK→UA_W	3097	3497	3497
ES→FR	2835	6835	6835
BX→RO	2425	2925	3275
RO→UA_W	1759	2159	2159
IT→SI	1555	3705	3705
HR→BX	1424	3634	3624
UK→NO	1400	2800	2800
CZ→SK	1382	3382	2382
DE→SE	1000	3490	3430
FI→BT	1000	2000	2000
IT→GR	1000	1500	1500
PL→BT	1000	2000	2000
SE→PL	1000	1600	1600
BX→BG	784	1534	1884
HU→RO	530	1130	1930
HU→BX	410	1010	1010
DE→CZ	336	2636	4136
FR→BL	160	4160	3260
HR→SI	158	2058	2058
IT→AT	77	2277	2277
UK→IE	77	1377	1007
FI→NO	64	164	164
CZ→PL	9	809	2009

Table 129: Optimal expansion values (additional capacity) and corresponding new NTC values (MW) in the 2030 MT scenario.

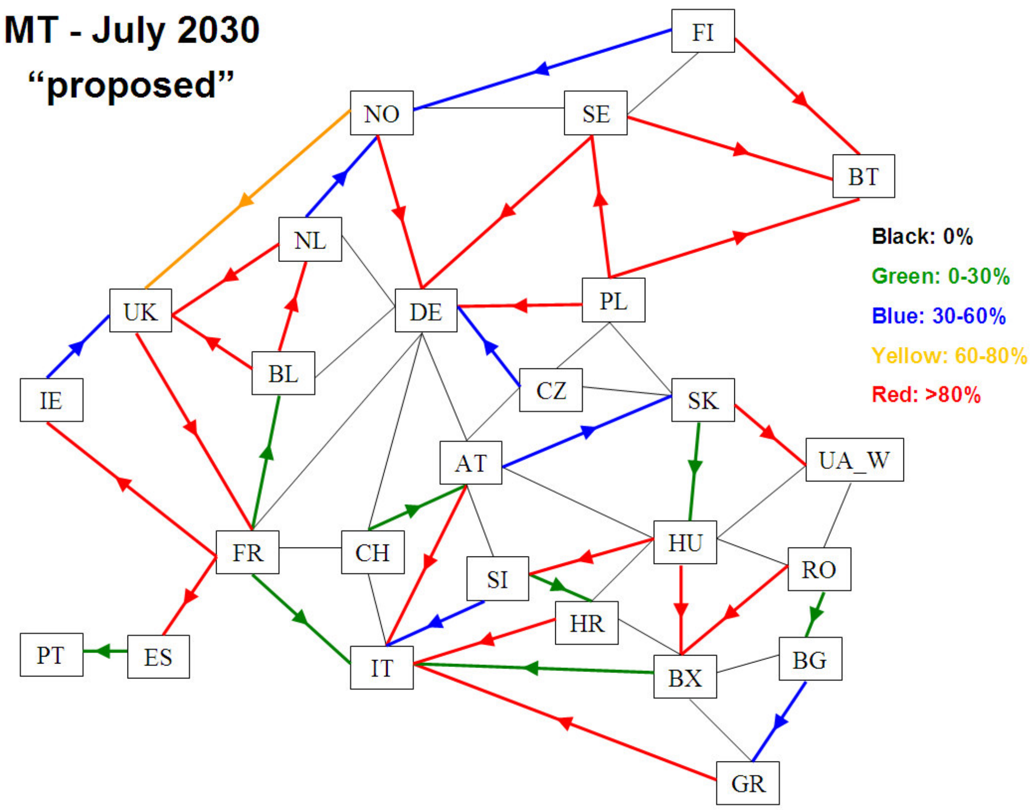

Figure 41: Percentages of hours with congestion in July 2030 with the "proposed expansion".

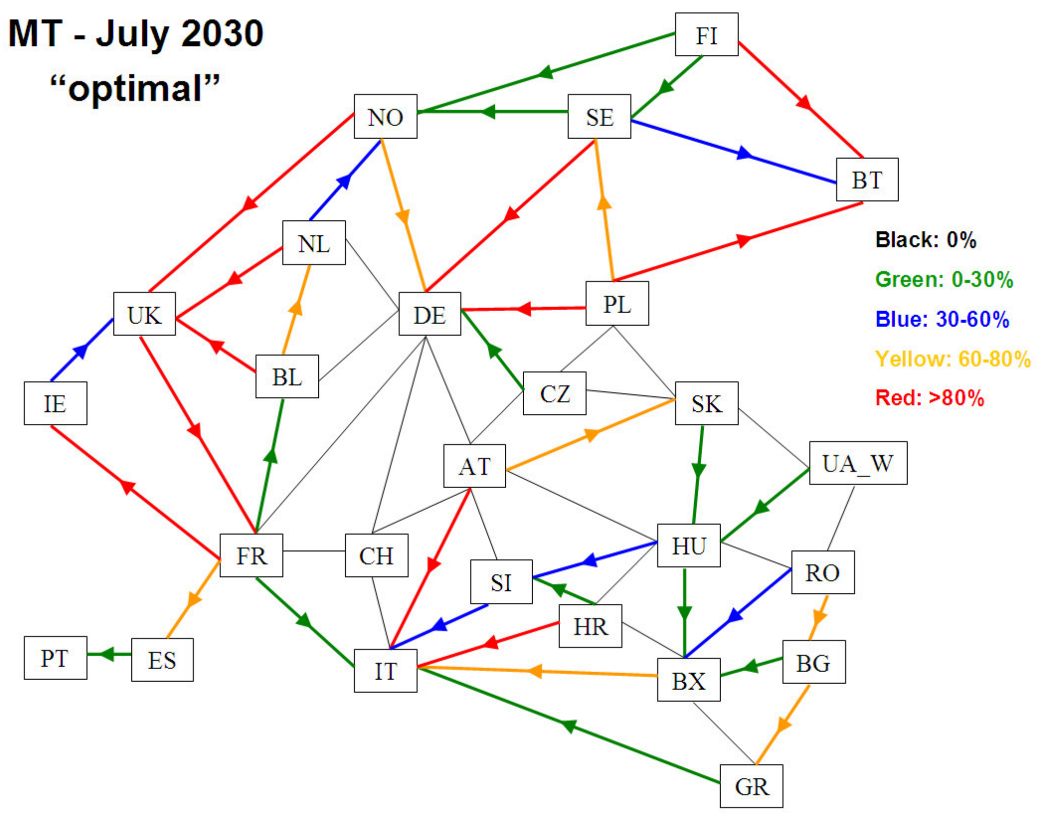

Figure 42: Percentages of hours with congestion in July 2030 with the "optimal expansion".

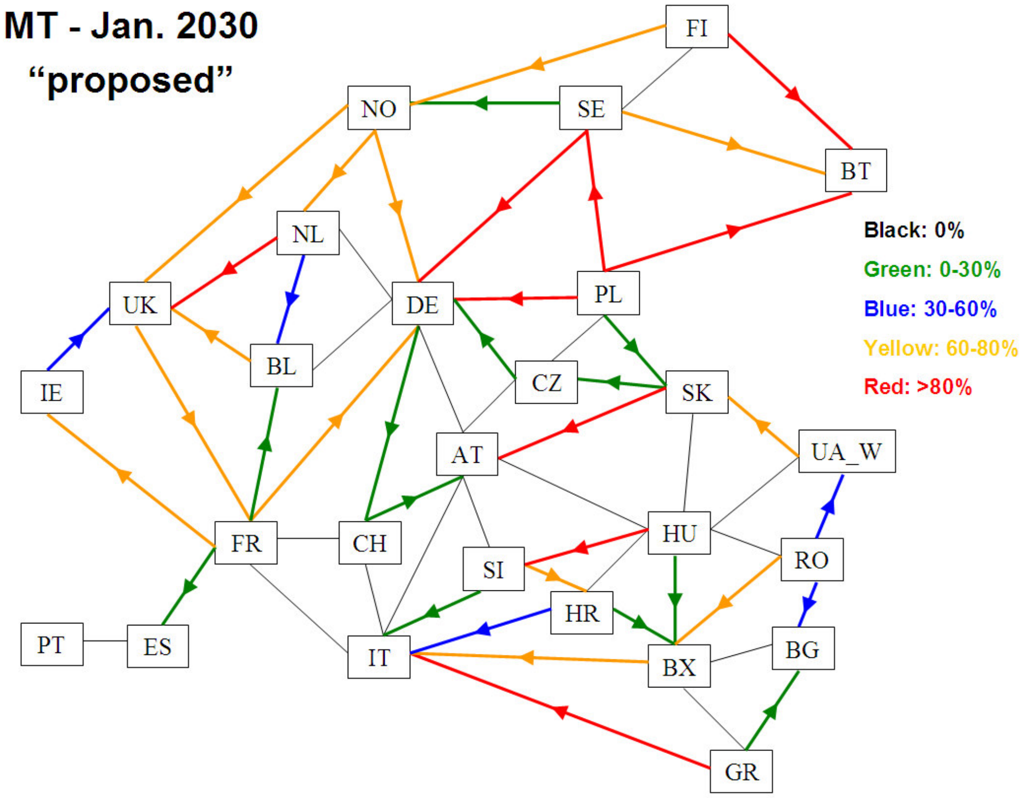

Figure 43: Percentages of hours with congestion in January 2030 with the “proposed expansion”.

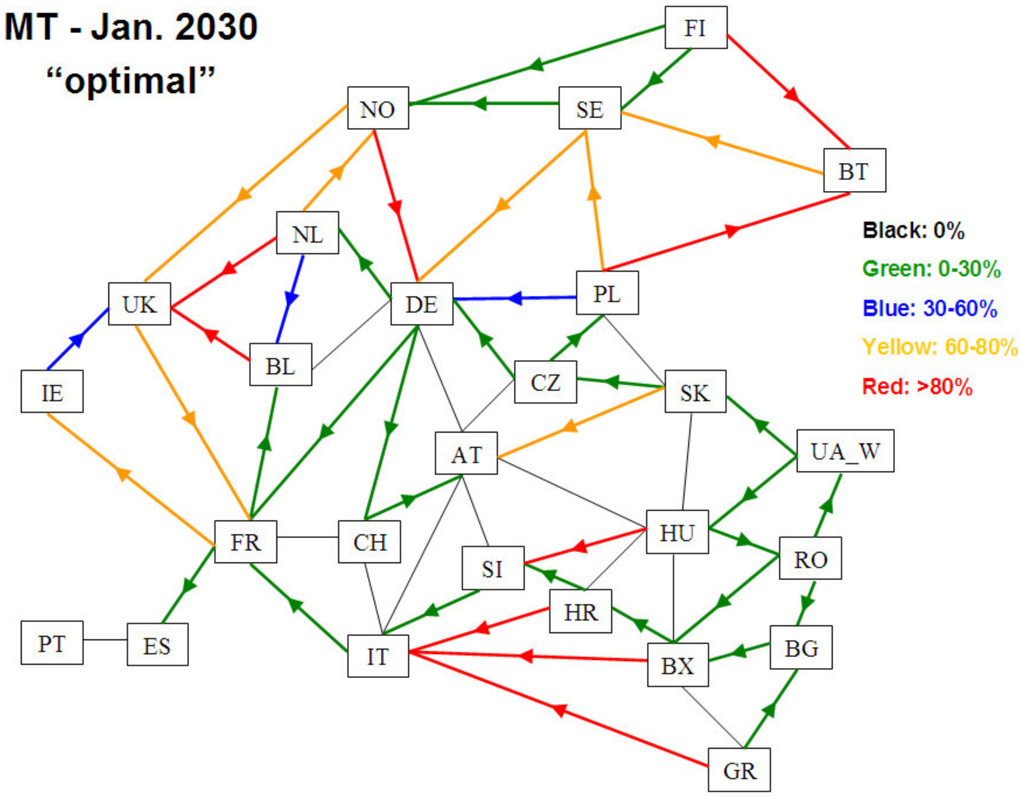

Figure 44: Percentages of hours with congestion in January 2030 with the “optimal expansion”.

In Figure 41, Figure 42, Figure 43 and Figure 44 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the "proposed expansion" and with the "optimal expansion" is reported.

In the July 2030 "optimal expansion" scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.

In the January 2030 "optimal expansion" scenario, congestion is still reduced, even if in a less significant way than in July 2030.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

Spain (ES) – France (FR)

- *"proposed expansion"*: congestion situation is critical from May to September, with an almost complete saturation in July and August; however, in the rest of the year, especially during winter months, congestion is not a problem;
- *"optimal expansion"*: congestions situation improves significantly throughout the year; only July remains critical, with a value around 80%.

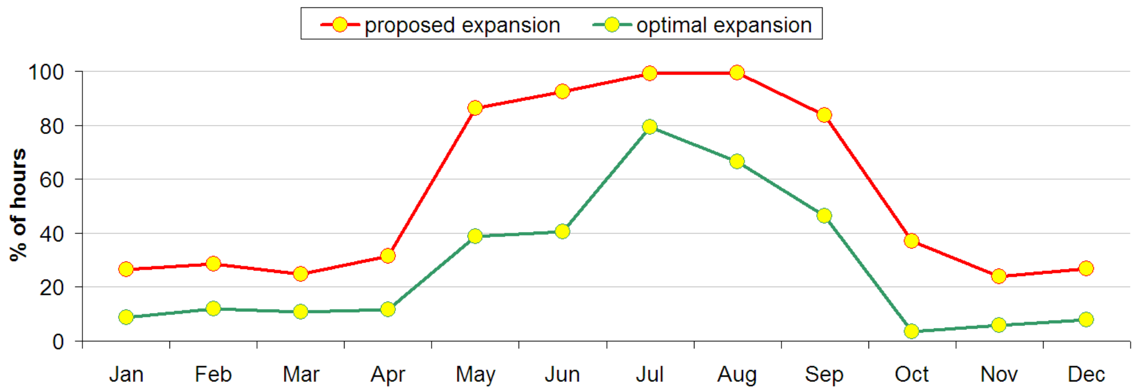

Figure 45: Percentages of congested hours in the Spain – France interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Poland (PL) – Germany and Denmark West (DE)

- *"proposed expansion"*: congestion situation is extremely critical throughout the whole year, with a complete saturation during nine months;
- *"optimal expansion"*: congestion situation improves especially in autumn and in winter; the percentage remains almost always in the range 60÷85%.

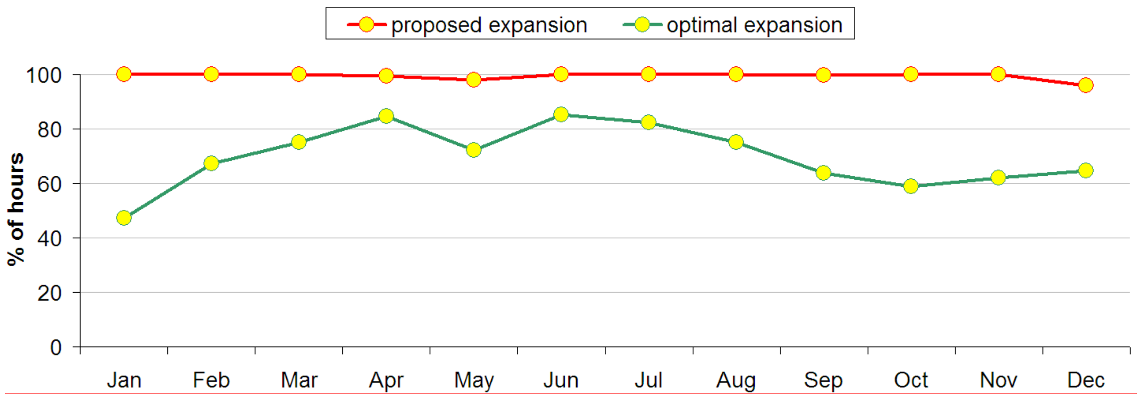

Figure 46: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Switzerland (CH) – Austria (AT)

- *"proposed expansion"*: the interconnection is completely saturated in April; congestion situation is relatively critical also in March, May, October and November;
- *"optimal expansion"*: congestion situation improves significantly in February, March and November, while in the remaining months there are no significant differences; the percentage in April is still high (93%).

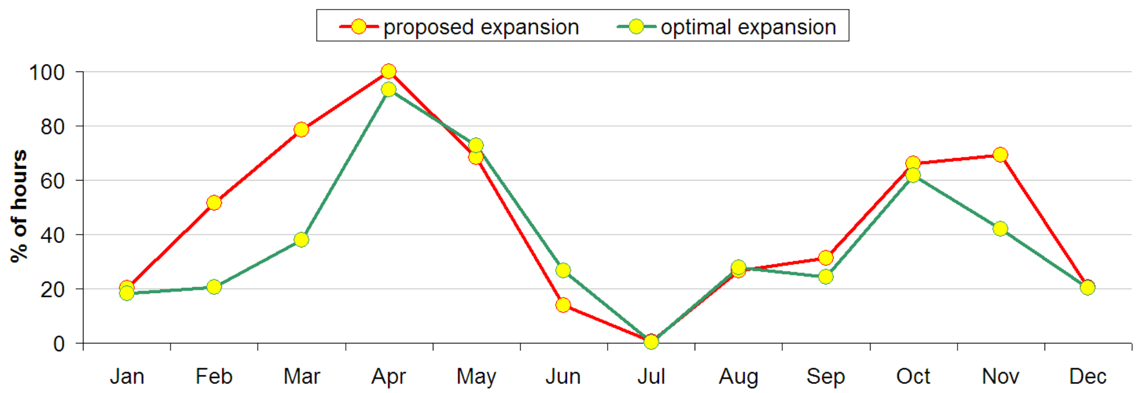

Figure 47: Percentages of congested hours in the Switzerland – Austria interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Austria (AT) – Italy (IT)

- *"proposed expansion"*: the interconnection is highly congested only during summer months, with a complete saturation in July; in winter there is no congestion;
- *"optimal expansion"*: congestion situation improves in a uniform manner, even though it remains quite critical in July (91%).

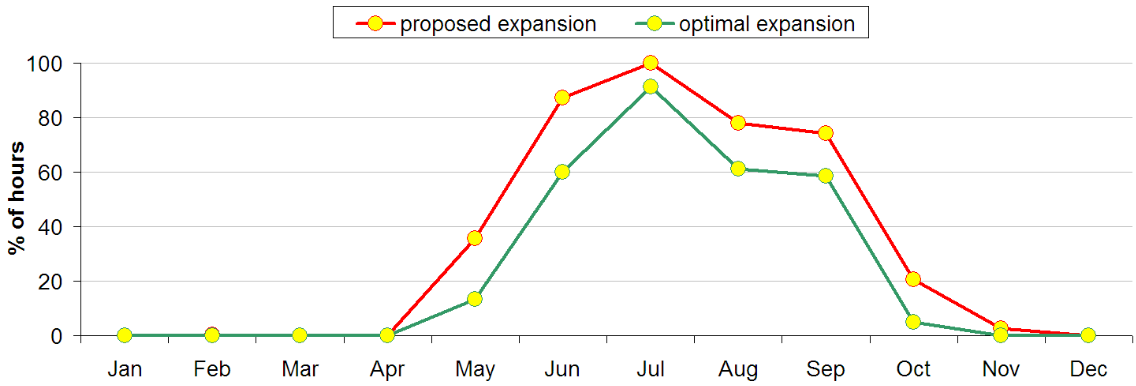

Figure 48: Percentages of congested hours in the Austria – Italy interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Romania (RO) – Balkan countries (BX)

- *"proposed expansion"*: congestion situation is quite critical between June and October, when the percentage is near full saturation;
- *"optimal expansion"*: congestions situation significantly improves throughout the year and in particular in autumn and winter, when congestion almost disappear.

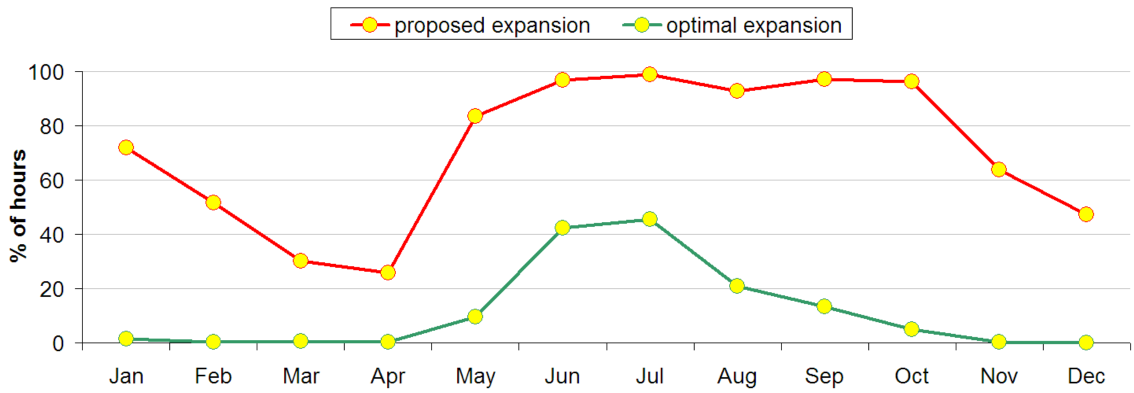

Figure 49: Percentages of congested hours in the Romania – Balkan countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Greece (GR) – Italy (IT)

- *"proposed expansion"*: the interconnection is completely saturated during autumn and winter; congestion situation is less critical in summer, even though the percentage is always greater than about 80%;
- *"optimal expansion"*: congestion situation improves significantly in summer, while in the rest of the year the situation remains critical.

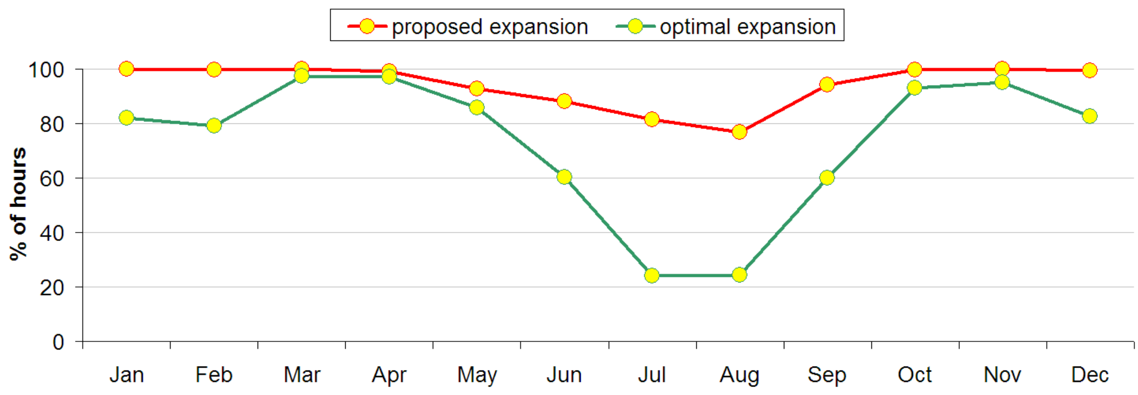

Figure 50: Percentages of congested hours in the Greece – Italy interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Sweden and Denmark East (SE) – Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is fully saturated between June and October and in the other months congestion situation remains critical;
- *"optimal expansion"*: congestion situation improves significantly throughout the year, except in February and in July when it remains quite critical.

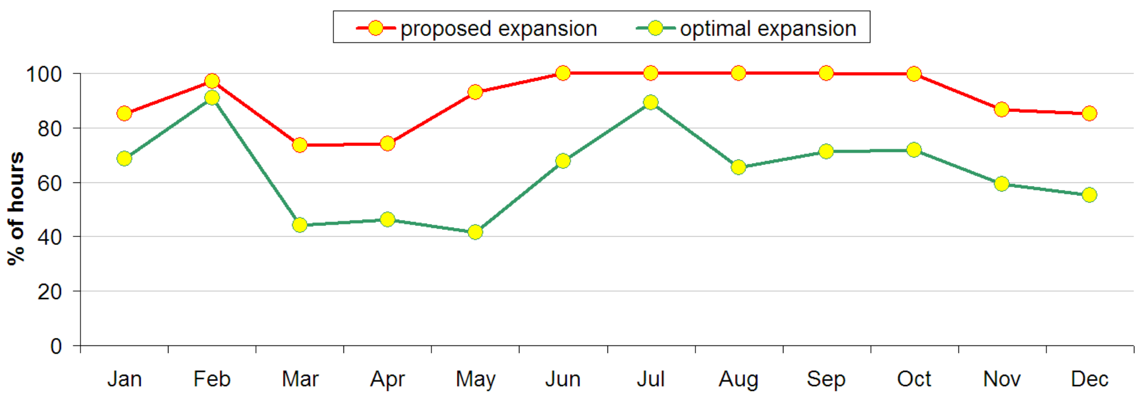

Figure 51: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

<u>Poland (PL) – Sweden and Denmark East (SE)</u>

- *"proposed expansion"*: congestion situation is extremely critical throughout the whole year, with the interconnection almost completely saturated;
- *"optimal expansion"*: congestion situation improves in an almost uniform manner throughout the year.

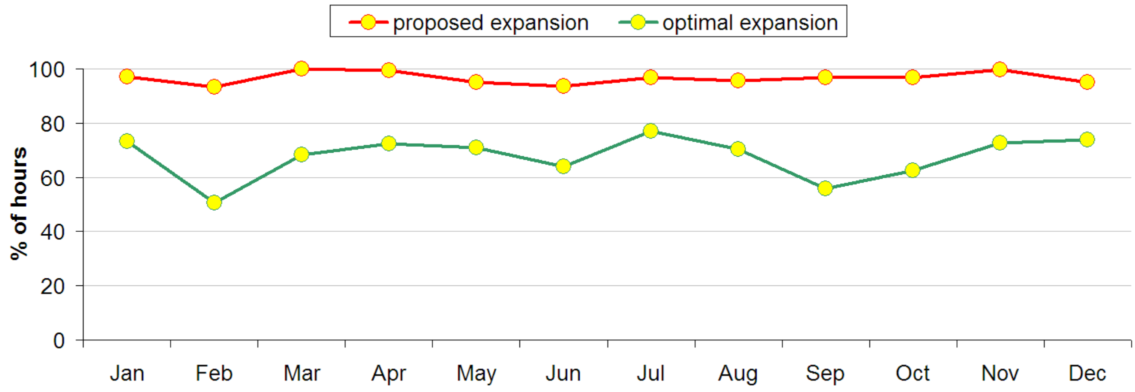

Figure 52: Percentages of congested hours in the Poland – Sweden and Denmark East interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

<u>Poland (PL) – Baltic countries (BT)</u>

- *"proposed expansion"*: congestion situation is extremely critical throughout the whole year, with the interconnection almost always completely saturated;
- *"optimal expansion"*: congestion situation improves in an almost uniform manner throughout the year, even if it remains critical, with percentages around 80%.

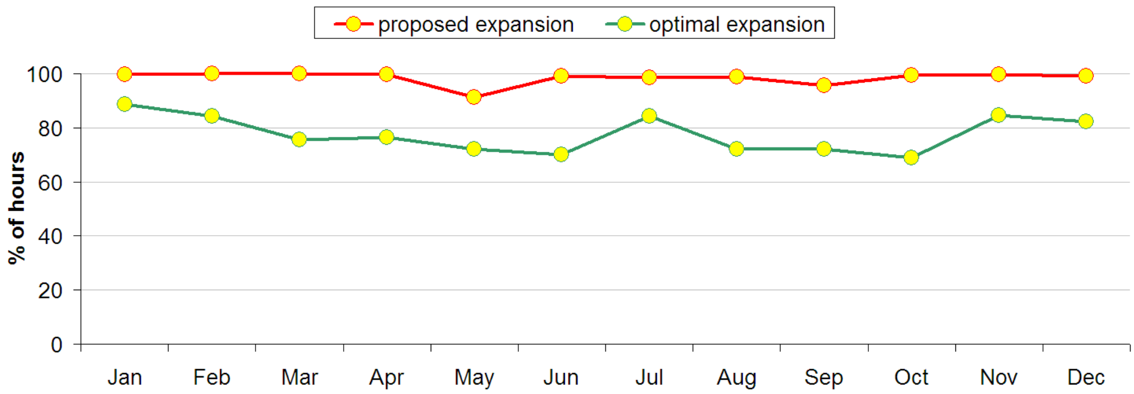

Figure 53: Percentages of congested hours in the Poland – Baltic countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Finland (FI) – Baltic countries (BT)

- *"proposed expansion"*: congestion situation is extremely critical throughout the whole year, with the interconnection almost always completely saturated;
- *"optimal expansion"*: congestion situation improves slightly throughout the year, but it remains quite critical, since that the percentage remains around 90%.

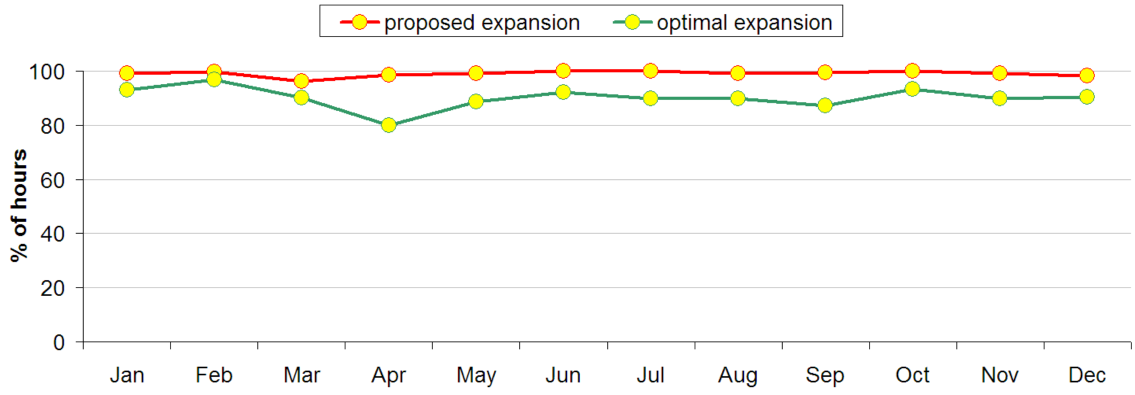

Figure 54: Percentages of congested hours in the Finland – Baltic countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios.

Impact on electricity prices

Similarly to paragraph 0, in Figure 55 we report the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.

It can be noted that the main "winners" in this scenario are United Kingdom, Germany, Baltic countries, Belgium, Ireland, The Netherlands and Switzerland while the main "losers" are Romania, Poland, Bulgaria, Ukraine West and Greece.

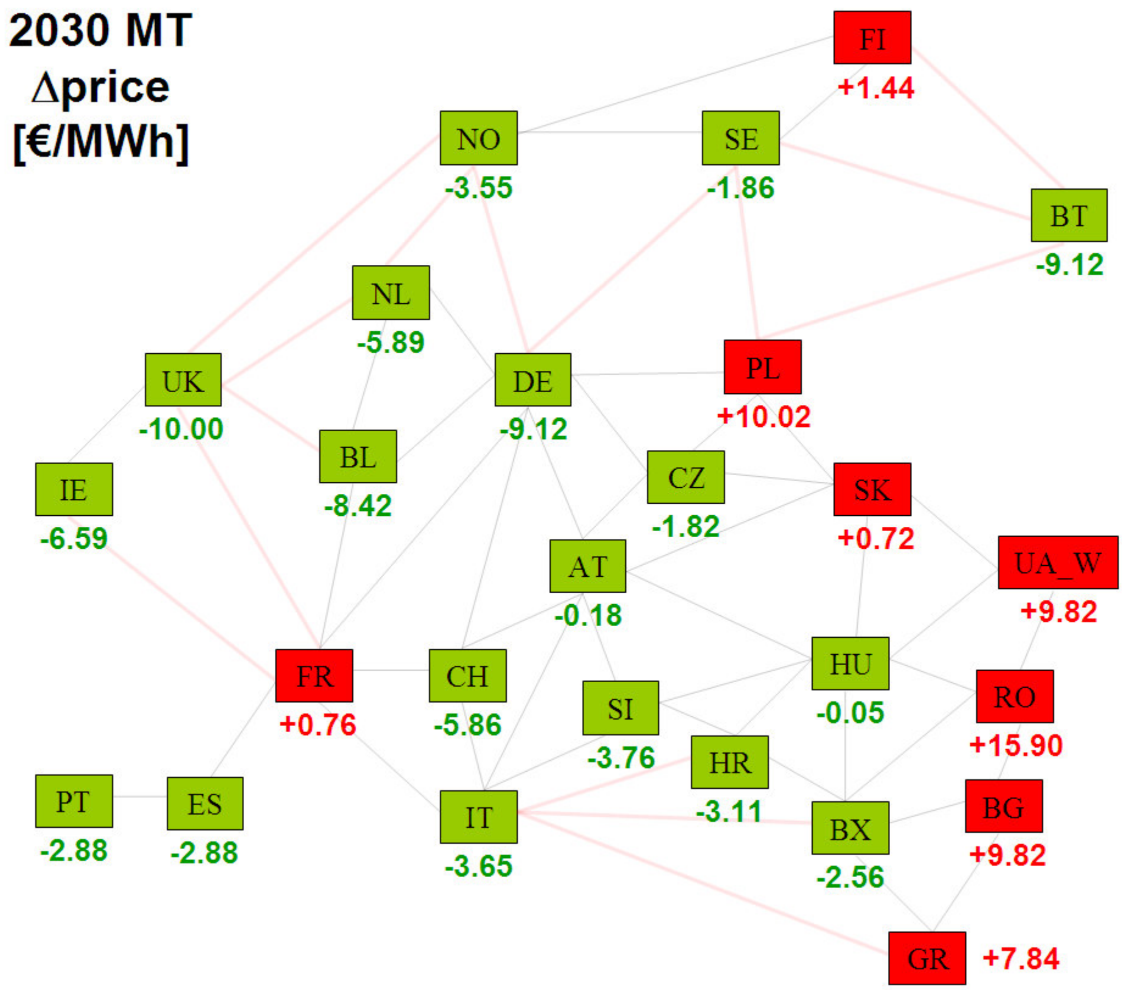

Figure 55: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2030 MT scenarios.

Impact on fuel consumption

In the following Table 130, a comparison between electricity production by different fuels of non-CHP power plants in the "proposed expansion" and in the "optimal expansion" scenarios is reported.

The consequence of the "optimal expansion" (that reduces network constraints) is an increase of production by cheaper base-load power plants (nuclear, hard coal, lignite and power plants equipped with CCS technology) at the expense of mid-merit / peak-load natural gas and fuel oil fired power plants.

In Table 131 the corresponding data in terms of fuel consumption are reported: the greater use of less efficient generation technologies slightly increases total fuel consumption.

Fuel	"proposed expansion" [GWh]	"optimal expansion" [GWh]	Δ [GWh]	Δ%
Nuclear	842515	843056	541	0.1
Hard coal	1187927	1222786	34859	2.9
Lignite	219024	229668	10644	4.9
Natural gas	268503	223198	-45305	-16.9
Fuel oil	902	241	-661	-73.3
Coal CCS	41381	41460	79	0.2
Gas CCS	4307	4334	27	0.6

Table 130: Comparison between electricity generation by different fuels of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios (GWh).

Fuel	"proposed expansion" [PJ]	"optimal expansion" [PJ]	Δ [PJ]	Δ%
Nuclear	8673.3	8679.2	5.9	0.1
Hard coal	9777.6	10064.9	287.3	2.9
Lignite	2267.5	2376.1	108.6	4.8
Natural gas	1948.9	1579.9	-369	-18.9
Fuel oil	10.7	5.3	-5.4	-50.5
Coal CCS	334.0	334.7	0.7	0.2
Gas CCS	28.2	28.4	0.2	0.7
Total	**23040.2**	**23068.5**	**28.3**	**0.1**

Table 131: Comparison between fuel consumption of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios (PJ).

Impact on CO_2 emissions

In the following Table 132 a comparison between CO_2 emissions by different fuels of non-CHP power plants in the "proposed expansion" and in the "optimal expansion" scenarios is reported.
Due to substitution of natural gas fired generation with less efficient and more emissive (apart from nuclear) power plants, overall CO_2 emissions increase, by about **16.9 $MtCO_2$**.

Fuel	"proposed expansion" [$MtCO_2$]	"optimal expansion" [$MtCO_2$]	Δ [$MtCO_2$]	Δ%
Hard coal	919.10	946.10	27.00	2.9
Lignite	229.20	240.18	10.98	4.8
Natural gas	109.14	88.48	-20.66	-18.9
Fuel oil	0.82	0.41	-0.41	-50.0
Coal CCS	3.14	3.15	0.01	0.3
Gas CCS	0.24	0.24	-	-
Total	**1261.64**	**1278.56**	**16.92**	**1.3**

Table 132: Comparison between CO_2 emissions of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios ($MtCO_2$).

Impact on costs

In the following Table 133 a comparison between each cost item of the modelled power system in the "proposed expansion" and in the "optimal expansion" scenarios is reported.
It can be noted that a significant reduction of fuel costs (about 1650 M€) is partially compensated by CO_2 emissions allowances and by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **728 millions of Euros**.

Cost item	"proposed expansion" [M€]	"optimal expansion" [M€]	Δ [M€]	Δ%
Fuel consumption	41789	40139	-1650	-3.9
CO_2 emissions allowances	30611	31022	411	1.3
Investments / O&M AC lines	-	199	199	-
Investments / O&M DC lines	-	312	312	-
TOTAL COSTS	**72400**	**71672**	**-728**	**-1.0**

Table 133: Comparison between costs of the modeled power system in the "proposed expansion" and in the "optimal expansion" 2030 MT scenarios (M€).

2030 “EA – Europe Alone” scenario

Impact on congestion

In the 2030 EA scenario, the simulation determined the optimal expansion (w.r.t. the *“proposed expansion”*) of cross-border transmission network reported in the following Table 134.

It can be noted that the expansion of the France – Germany and Denmark West interconnection is extremely high in this scenario, being around 17 GW, that could be unrealistic. In any case we remark that the objective of this study is not to determine the realistic cross-border network expansion potentials on each frontier (that would require an analysis site by site of a multitude of other factors outside the scope of this project), but the definition of “optimal” expansion levels to be considered as targets to which it would be convenient to go as near as possible.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
FR→DE	17019	19919	20069
DE→PL	6795	9295	9195
ES→FR	2178	6178	6178
SE→PL	2000	2600	2600
SK→UA_W	1949	2349	2349
BX→RO	1736	2236	2586
RO→UA_W	1415	1815	1815
DE→NO	1000	5000	5000
DE→SE	1000	3490	3430
FI→BT	1000	2000	2000
PL→BT	1000	2000	2000
FR→BL	804	4804	3904
CZ→SK	695	2695	2695
IT→AT	614	2814	2814
RO→BG	554	1504	1504
BX→BG	399	1149	1499
HU→RO	308	908	1708
HU→BX	261	861	861
FR→IT	211	4411	2806
CH→AT	71	1471	1471
BG→GR	40	1540	1440
UK→NO	3	1403	1403

Table 134: Optimal expansion values (additional capacity) and corresponding new NTC values (MW) in the 2030 EA scenario.

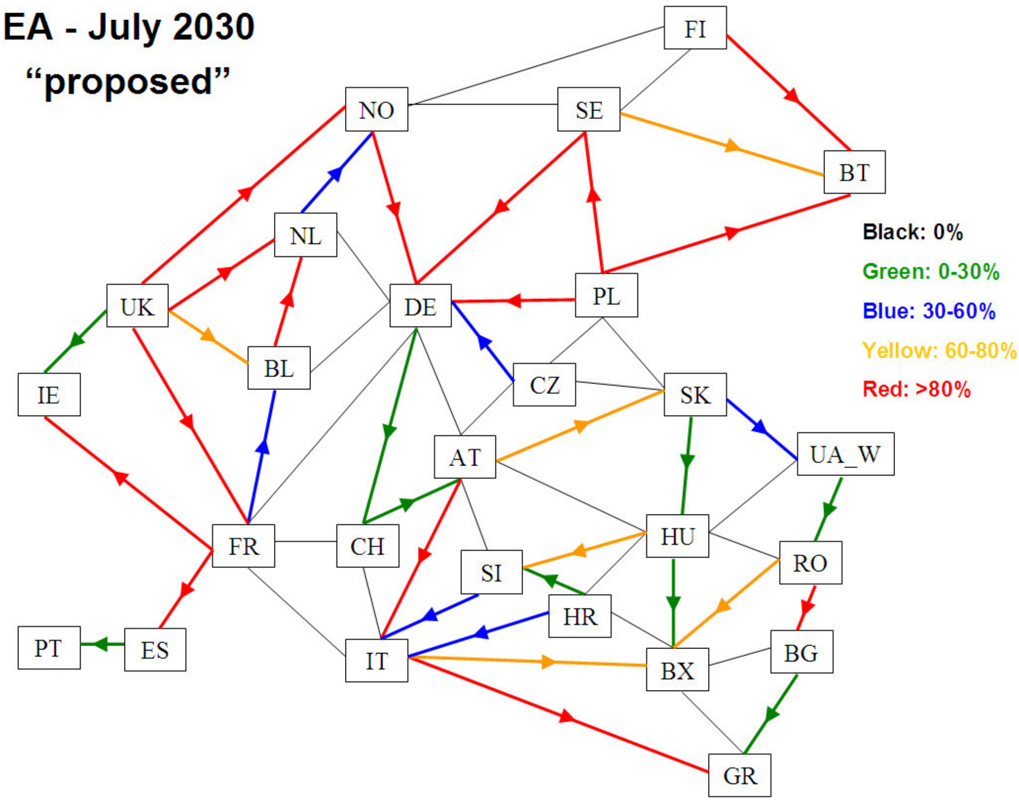

Figure 56: Percentages of hours with congestion in July 2030 with the "proposed expansion".

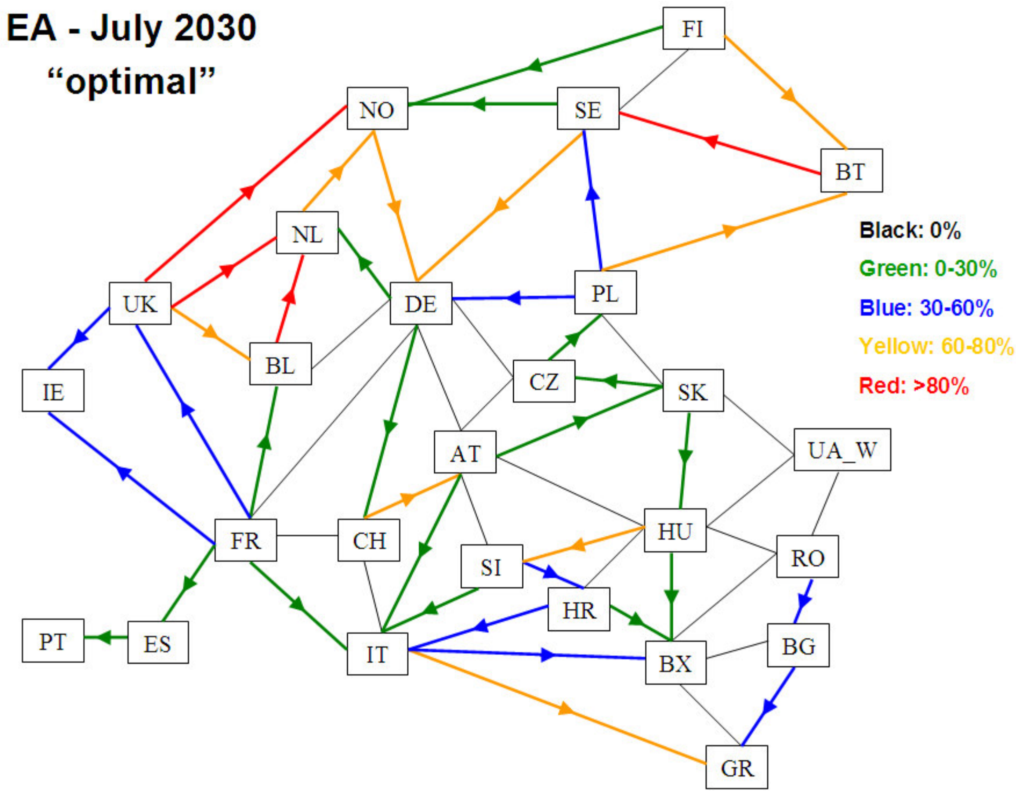

Figure 57: Percentages of hours with congestion in July 2030 with the "optimal expansion".

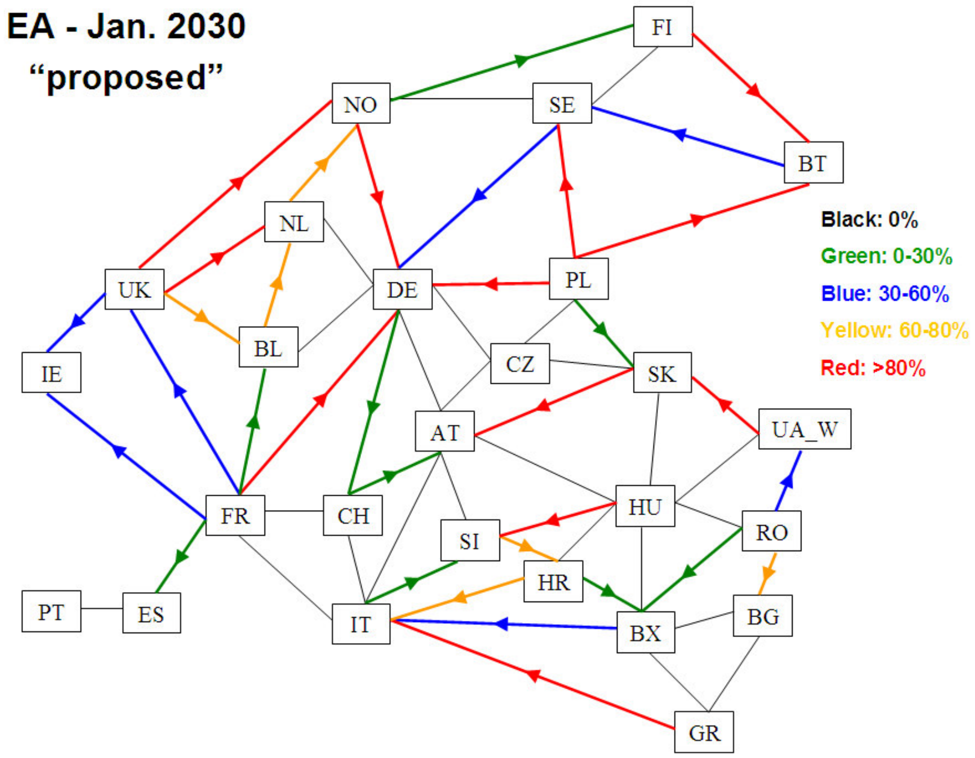

Figure 58: Percentages of hours with congestion in January 2030 with the "proposed expansion".

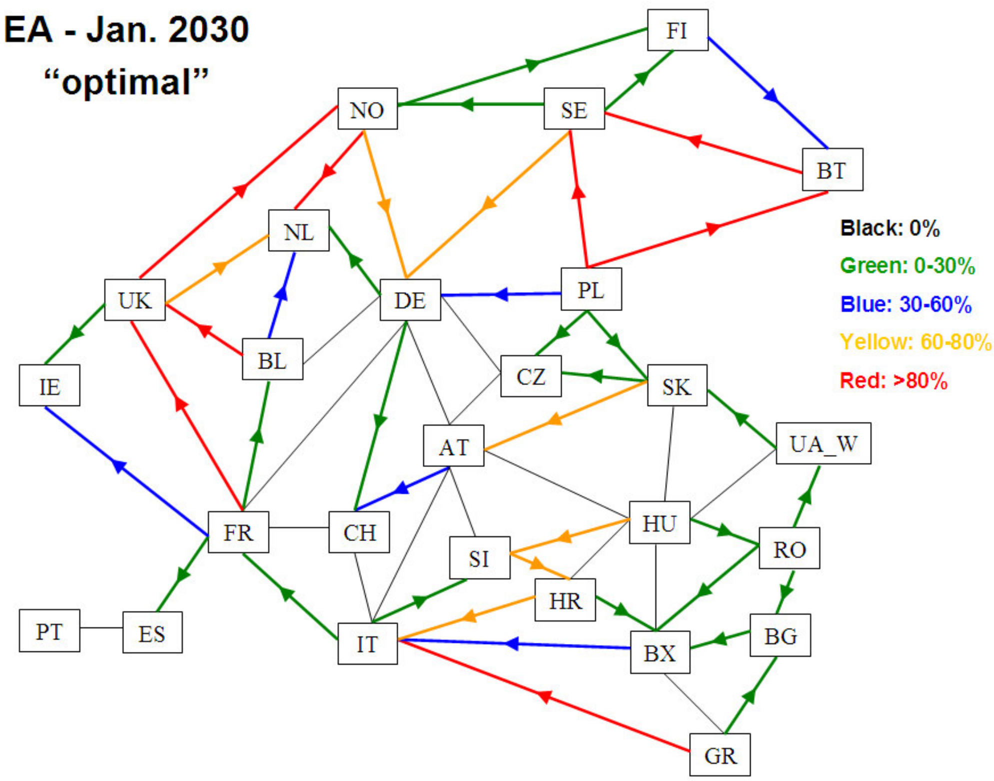

Figure 59: Percentages of hours with congestion in January 2030 with the "optimal expansion".

In Figure 56, Figure 57, Figure 58 and Figure 59 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the "proposed expansion" and with the "optimal expansion" is reported.

In the July 2030 "optimal expansion" scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is reduced to one third.

In the January 2030 "optimal expansion" scenario, congestion is still reduced, even if in a less significant way than in July 2030.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

France (FR) – Spain (ES)

- *"proposed expansion"*: congestion situation is particularly critical between May and September, when the interconnection is almost completely saturated;
- *"optimal expansion"*: congestion dramatically decreases, with percentages below 20% throughout the year.

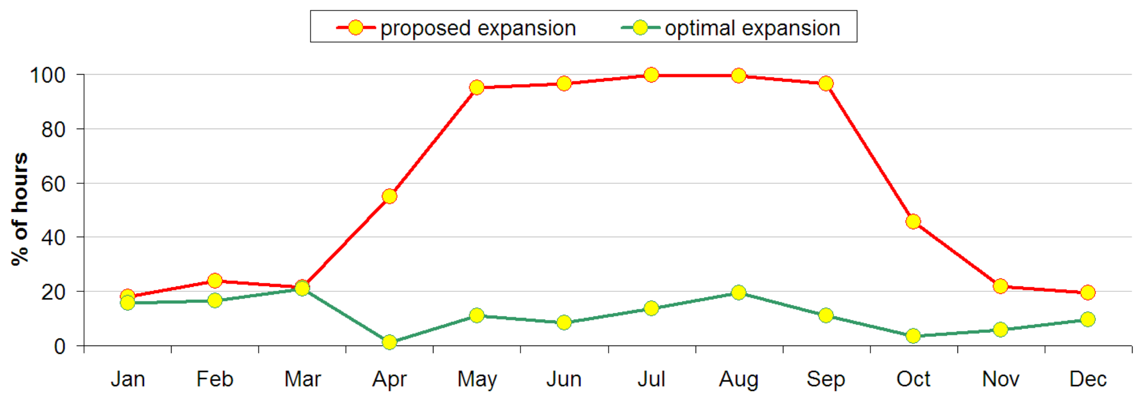

Figure 60: Percentages of congested hours in the France – Spain interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

France (FR) – Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is highly congested only between January and April and in October and November; from May to September there is no congestion at all;
- *"optimal expansion"*: in the previously congested months, congestion dramatically decreases, with percentages below 20%.

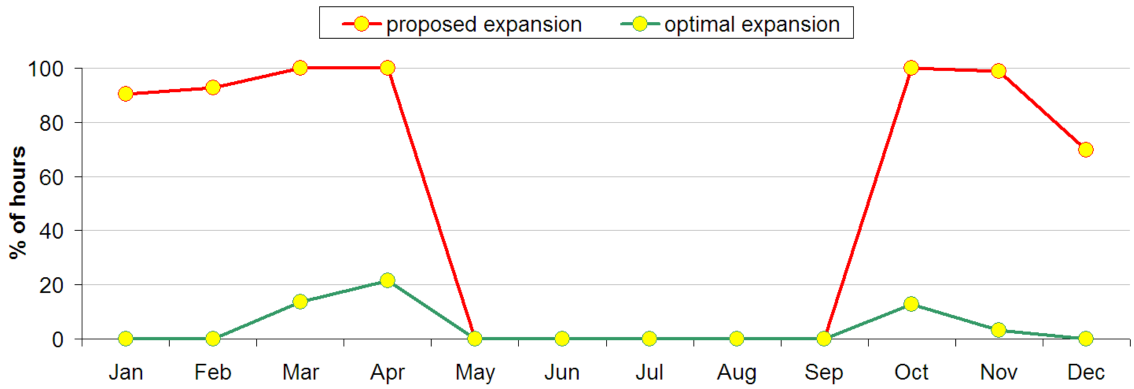

Figure 61: Percentages of congested hours in the France – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Belgium and Luxembourg (BL) – The Netherlands (NL)

- *"proposed expansion"*: congestion situation is quite critical throughout the year, with an almost complete saturation in several months, but with a slight improvement in winter;
- *"optimal expansion"*: congestion situation improves significantly; only in July and August percentages remain critical, around 80%.

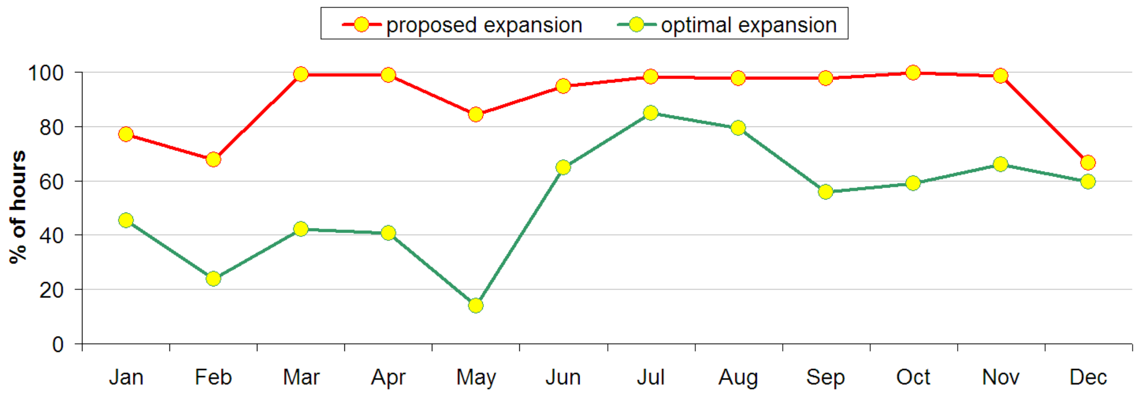

Figure 62: Percentages of congested hours in the Belgium and Luxembourg – The Netherlands interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Poland (PL) - Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is completely saturated throughout the entire year, except December;
- *"optimal expansion"*: congestion situation improves significantly, with percentages around 40% or below.

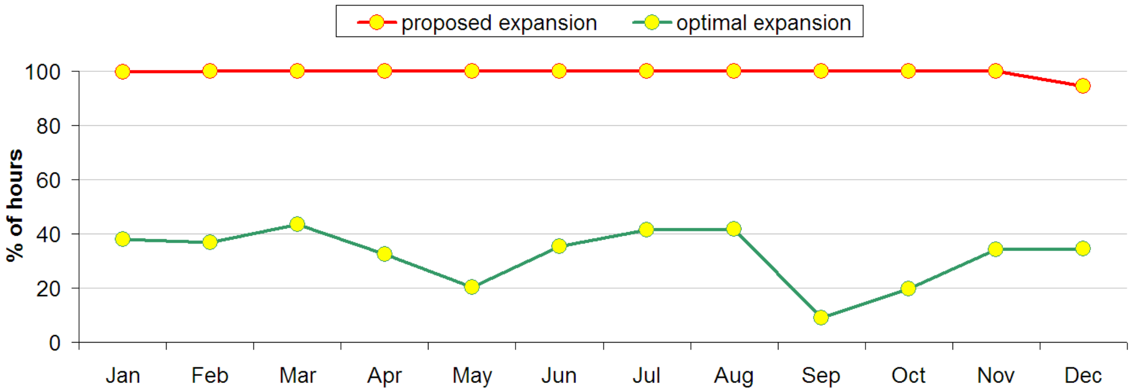

Figure 63: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Romania (RO) – Balkan countries (BX)

- *"proposed expansion"*: congestions situation is relatively critical from April to October, with a peak in May and in June, when the interconnection is almost completely saturated;
- *"optimal expansion"*: congestion dramatically decreases, with percentages below 20% throughout the year.

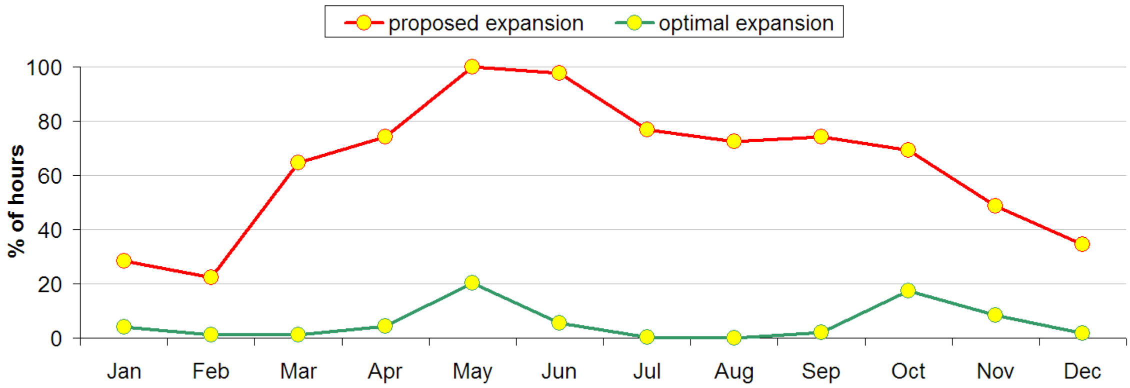

Figure 64: Percentages of congested hours in the Romania – Balkan countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

United Kingdom (UK) - Norway (NO)

- *"proposed expansion"*: congestion situation is quite critical throughout the year, with percentages almost always higher than 90%;
- *"optimal expansion"*: congestion situation improves a little, but it remains critical, with percentages higher than 80% throughout the year.

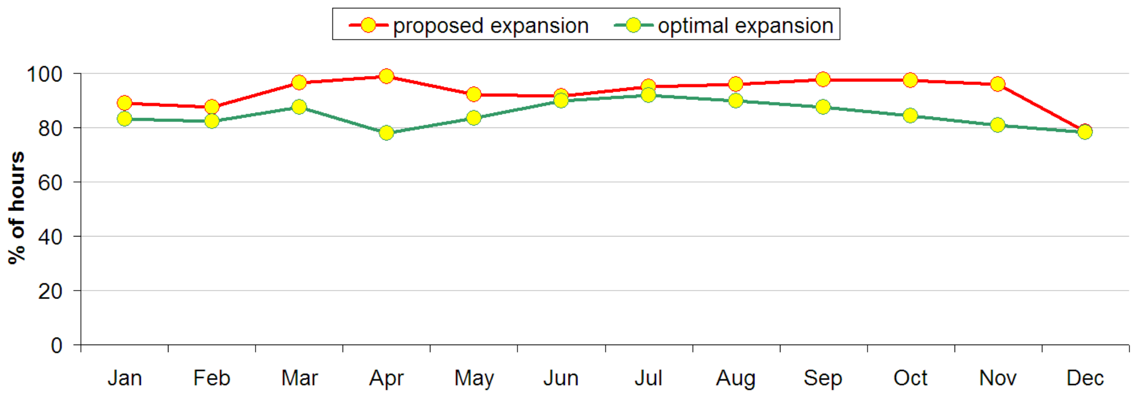

Figure 65: Percentages of congested hours in the United Kingdom – Norway interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

France (FR) - Republic of Ireland (IE)

- *"proposed expansion"*: congestion situation is highly critical in spring and in summer, with an almost complete saturation from May to August;
- *"optimal expansion"*: congestion situation improves in an almost uniform manner throughout the year, with percentages between 40% and 80%.

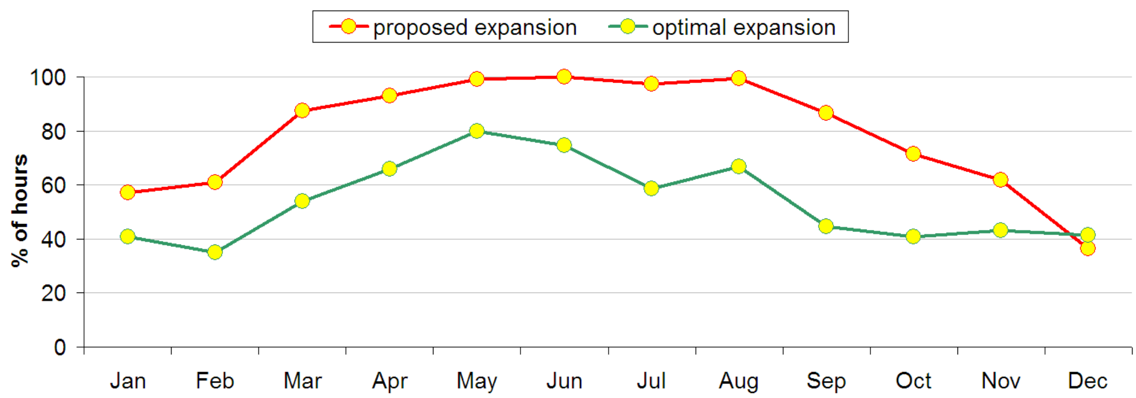

Figure 66: Percentages of congested hours in the France – Ireland interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

United Kingdom (UK) - France (FR)

- *"proposed expansion"*: congestion situation is very critical between May and August, when the interconnection is almost completely saturated;
- *"optimal expansion"*: congestion situation improves in spring and in summer, but worsen in autumn and in winter; percentages are almost always in the range 60% ÷ 85% throughout the year.

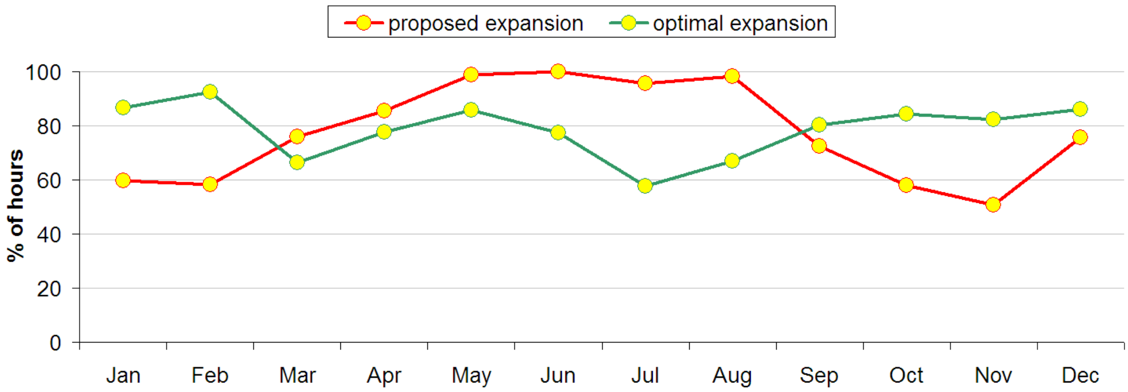

Figure 67: Percentages of congested hours in the United Kingdom – France interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Norway (NO) - Germany and Denmark West (DE)

- *"proposed expansion"*: congestion situation is extremely critical throughout the year, with the interconnection almost always saturated;
- *"optimal expansion"*: congestion situation improves significantly, with percentages always below 80%.

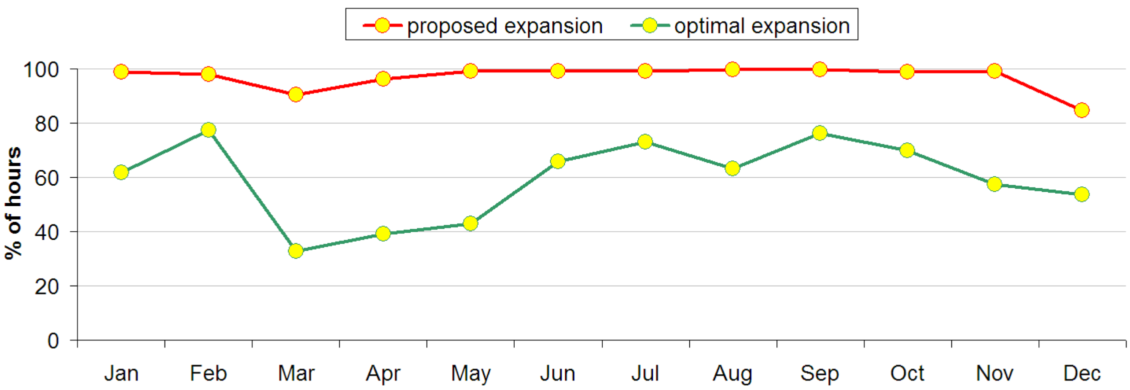

Figure 68: Percentages of congested hours in the Norway – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Sweden and Denmark East (SE) - Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is completely saturated between June and September; in the remaining months, except February and October (90%), congestion situation is not critical;
- *"optimal expansion"*: congestion situation improves when it was more critical and worsen when it was less critical; percentages remain in the range 60% ÷ 80% throughout the year.

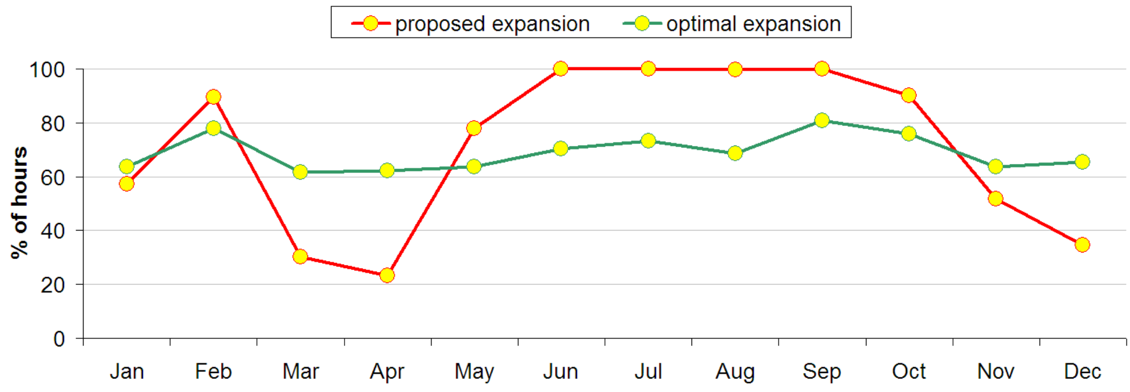

Figure 69: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Poland (PL) - Sweden and Denmark East (SE)

- *"proposed expansion"*: congestion situation is extremely critical, since the interconnection is completely saturated throughout the entire year;
- *"optimal expansion"*: congestion situation improves significantly, but only in spring and in summer.

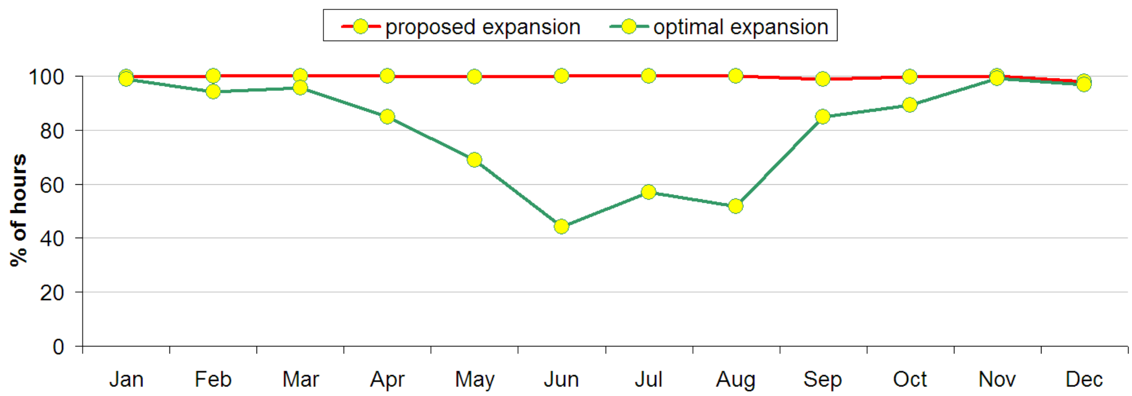

Figure 70: Percentages of congested hours in the Poland – Sweden and Denmark East interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Poland (PL) – Baltic countries (BT)

- *"proposed expansion"*: congestion situation is extremely critical, since the interconnection is almost completely saturated throughout the entire year;
- *"optimal expansion"*: congestion situation improves a little especially in summer, but percentages remain always over 80%.

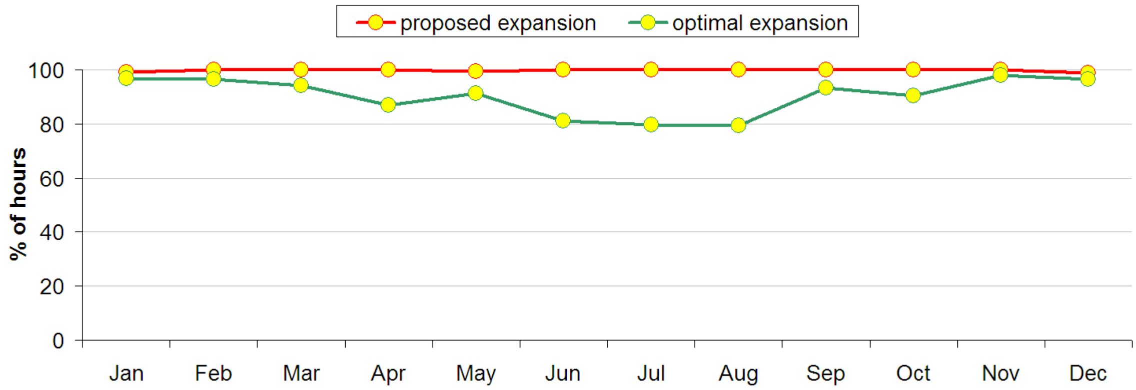

Figure 71: Percentages of congested hours in the Poland – Baltic countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Finland (FI) – Baltic countries (BT)

- *"proposed expansion"*: congestion situation is highly critical throughout the year, since the interconnection is almost completely saturated;
- *"optimal expansion"*: congestion situation improves significantly with only a few months around 80%.

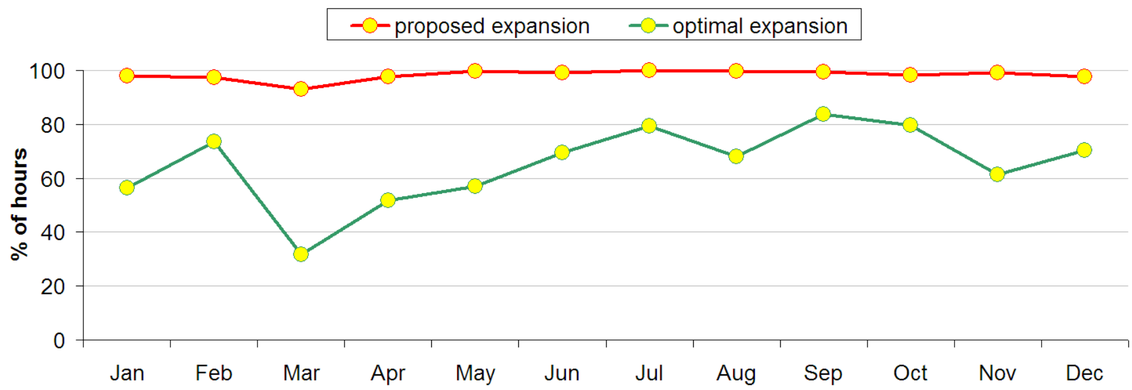

Figure 72: Percentages of congested hours in the Finland – Baltic countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios.

Impact on electricity prices

Similarly to paragraph 0, in Figure 55 we report the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.

It can be noted that the main "winners" in this scenario are Germany, Baltic countries, Norway, Sweden, Finland and The Netherlands while the main "losers" are Romania, France, Ukraine West, Poland, Bulgaria, and Greece.

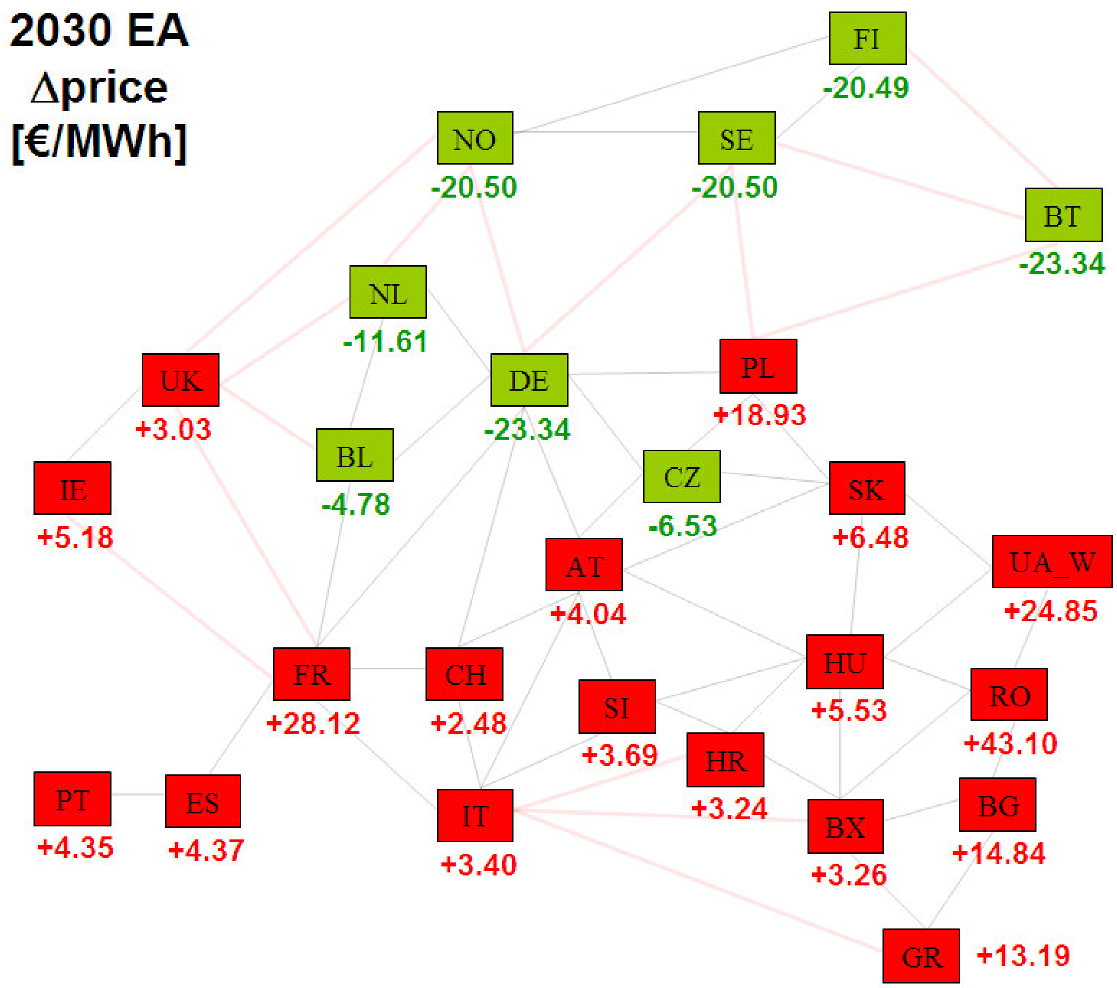

Figure 73: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2030 EA scenarios.

Impact on fuel consumption

In the following Table 135, a comparison between electricity production by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

The consequence of the “optimal expansion” (that reduces network constraints) is an increase of production by power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology) at the expense of the more emissive ones (hard coal, lignite and fuel oil). In fact, the “Europe Alone” scenario is characterized by a very high CO_2 emissions value (about 90 €/tCO_2: see paragraph 0).

In Table 136 the corresponding data in terms of fuel consumption are reported: the greater use of less emissive generation technologies slightly decreases total fuel consumption.

Fuel	“proposed expansion” [GWh]	“optimal expansion” [GWh]	Δ [GWh]	Δ%
Nuclear	982103	1000961	18858	1.9
Hard coal	178057	133354	-44703	-25.1
Lignite	63056	43406	-19650	-31.2
Natural gas	317887	340532	22645	7.1
Fuel oil	11	0	-11	-100
Coal CCS	302703	319779	17076	5.6
Gas CCS	123269	128521	5252	4.3

Table 135: Comparison between electricity generation by different fuels of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios (GWh).

Fuel	“proposed expansion” [PJ]	“optimal expansion” [PJ]	Δ [PJ]	Δ%
Nuclear	10064.1	10262.6	198.5	2.0
Hard coal	1581.5	1099.3	-482.2	-30.5
Lignite	649.3	448.0	-201.3	-31.0
Natural gas	2201.5	2329.0	127.5	5.8
Fuel oil	2.1	0	-2.1	-100
Coal CCS	2472.2	2611.8	139.6	5.6
Gas CCS	806.8	841.2	34.4	4.3
Total	**17777.5**	**17591.9**	**-185.6**	**-1.0**

Table 136: Comparison between fuel consumption of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios (PJ).

Impact on CO_2 emissions

In the following Table 137 a comparison between CO_2 emissions by different fuels of non-CHP power plants in the "proposed expansion" and in the "optimal expansion" scenarios is reported.

Due to substitution of more emissive generation with less emissive one, overall CO_2 emissions significantly decrease, by about **57 MtCO$_2$**.

Fuel	"proposed expansion" [MtCO$_2$]	"optimal expansion" [MtCO$_2$]	Δ [MtCO$_2$]	Δ%
Hard coal	148.66	103.34	-45.32	-30.5
Lignite	65.63	45.29	-20.34	-31.0
Natural gas	123.28	130.52	7.24	5.9
Fuel oil	0.16	0	-0.16	-100
Coal CCS	23.24	24.55	1.31	5.6
Gas CCS	6.78	7.07	0.29	4.3
Total	**367.75**	**310.77**	**-56.98**	**-15.5**

Table 137: Comparison between CO_2 emissions of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios (MtCO$_2$).

Impact on costs

In the following Table 138 a comparison between each cost item of the modelled power system in the "proposed expansion" and in the "optimal expansion" scenarios is reported.

It can be noted that the very high reduction of CO_2 costs (5145 M€) is only partially compensated by the increase of fuel costs and by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **4362 millions of Euros**.

Cost item	"proposed expansion" [M€]	"optimal expansion" [M€]	Δ [M€]	Δ%
Fuel consumption	34802	35039	237	0.7
CO_2 emissions allowances	33200	28055	-5145	-15.5
Investments / O&M AC lines	-	257	257	-
Investments / O&M DC lines	-	289	289	-
TOTAL COSTS	**68002**	**63640**	**-4362**	**-6.4**

Table 138: Comparison between costs of the modeled power system in the "proposed expansion" and in the "optimal expansion" 2030 EA scenarios (M€).

2030 “GR-FT – Global Regime with Full Trade” scenario

Impact on congestion

In the 2030 GR-FT scenario, the simulation determined the optimal expansion (w.r.t. the *“proposed expansion”*) of cross-border transmission network reported in the following Table 139.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
FR→DE	13596	16496	16646
DE→PL	7464	9964	9864
SK→UA_W	1818	2218	2218
ES→FR	1639	5639	5639
BX→RO	1357	1857	2207
RO→UA_W	1216	1616	1616
DE→NO	1000	5000	5000
FI→BT	1000	2000	2000
FR→IE	1000	2000	2000
PL→BT	1000	2000	2000
SE→PL	1000	1600	1600
FR→BL	578	4578	3678
RO→BG	570	1520	1520
CZ→SK	461	2461	1461
HU→BX	237	837	837
HU→RO	215	815	1615
BG→GR	189	1689	1589
BX→BG	132	882	1232

Table 139: Optimal expansion (additional capacity) values and corresponding new NTC values (MW) in the 2030 GR-FT scenario.

In Figure 74, Figure 75, Figure 76 and Figure 77 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the “proposed expansion” and with the “optimal expansion” is reported.

In the July 2030 “optimal expansion” scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.

More or less the same happens in the January 2030 “optimal expansion” scenario.

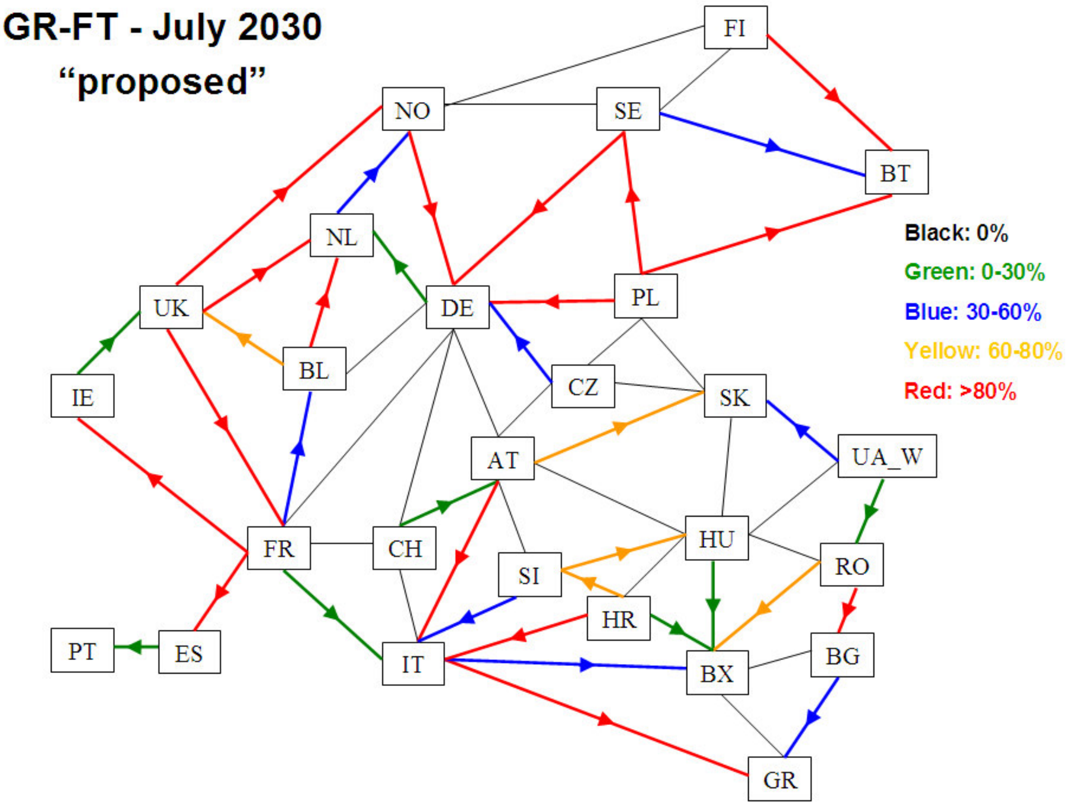

Figure 74: Percentages of hours with congestion in July 2030 with the "proposed expansion".

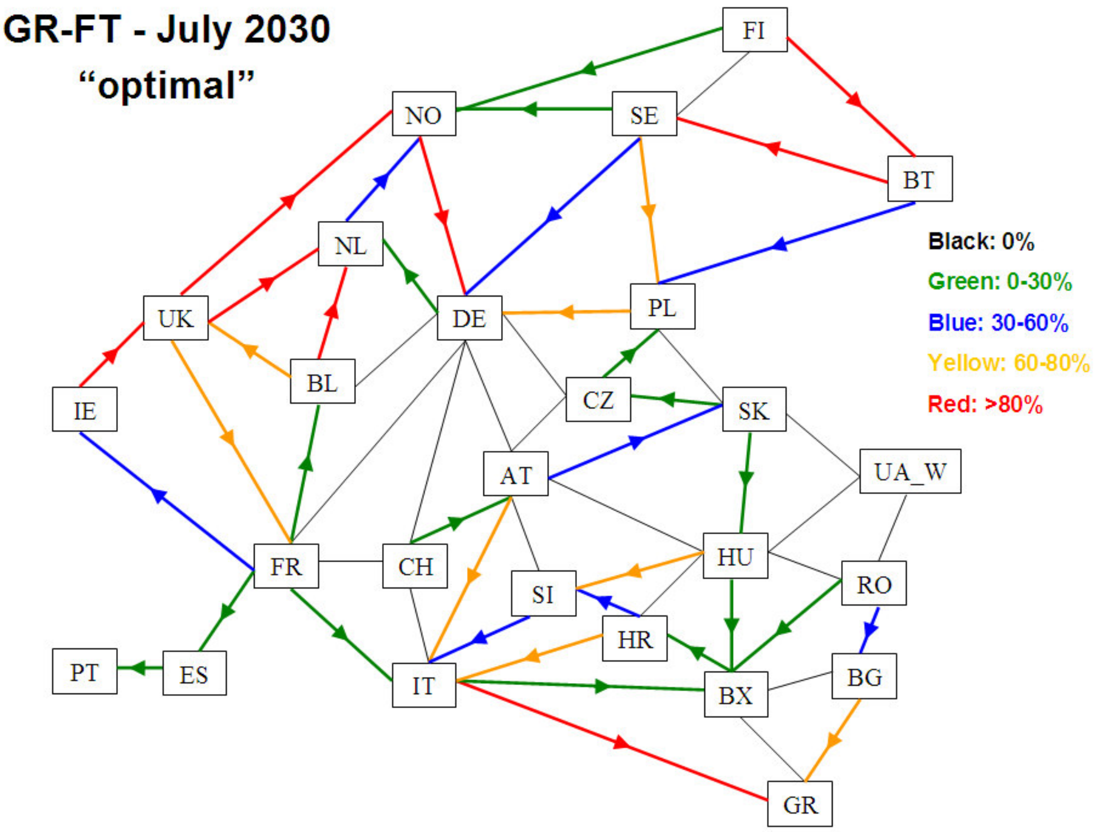

Figure 75: Percentages of hours with congestion in July 2030 with the "optimal expansion".

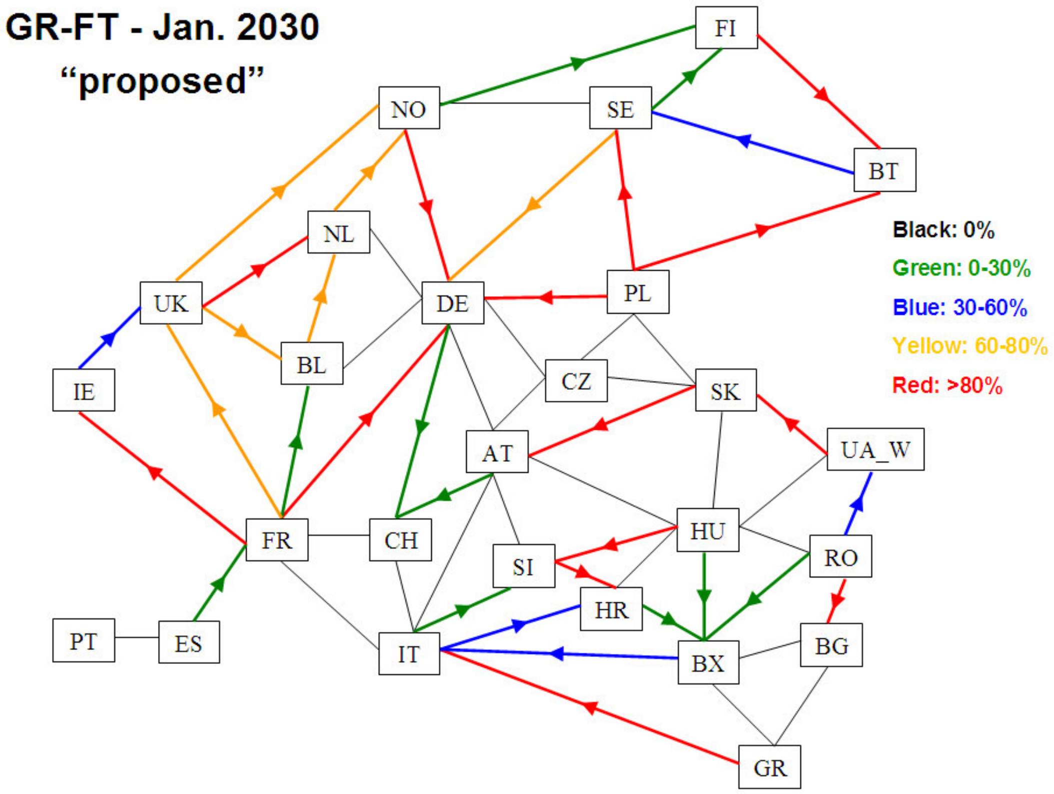

Figure 76: Percentages of hours with congestion in January 2030 with the “proposed expansion”.

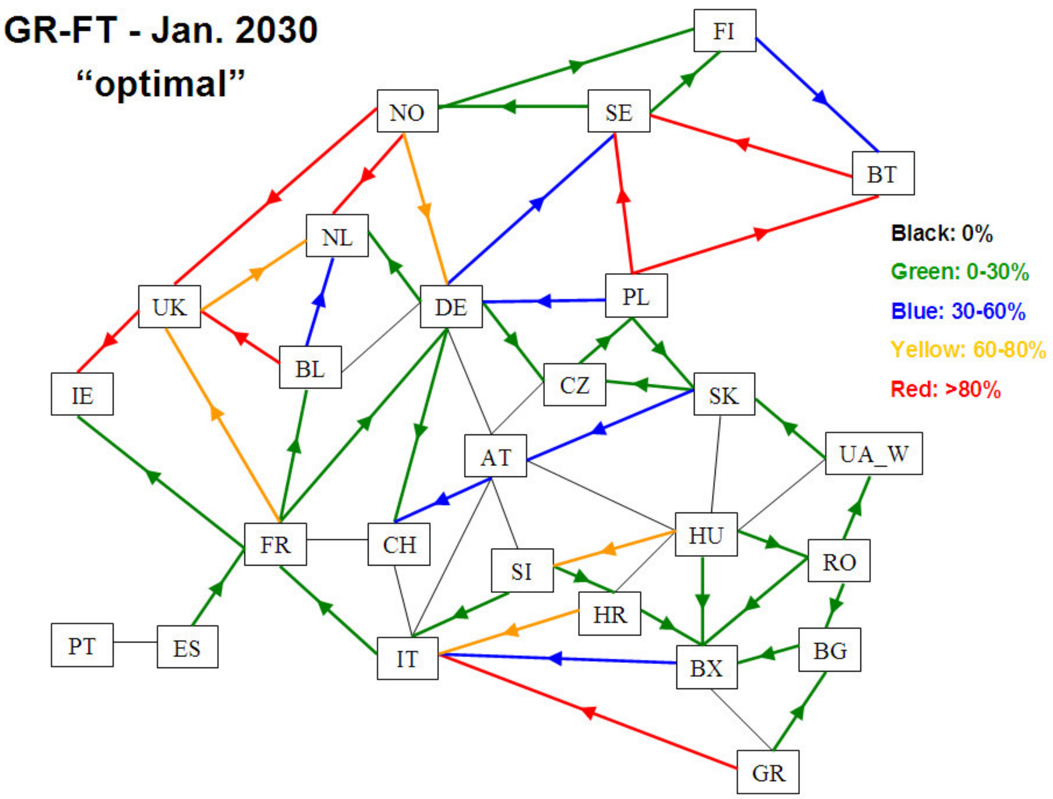

Figure 77: Percentages of hours with congestion in January 2030 with the “optimal expansion”.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

France (FR) – Spain (ES)

- *"proposed expansion"*: congestion situation is particularly critical between May and September, when the interconnection is almost completely saturated;
- *"optimal expansion"*: congestion dramatically decreases, with percentages below 20% throughout the year (except March).

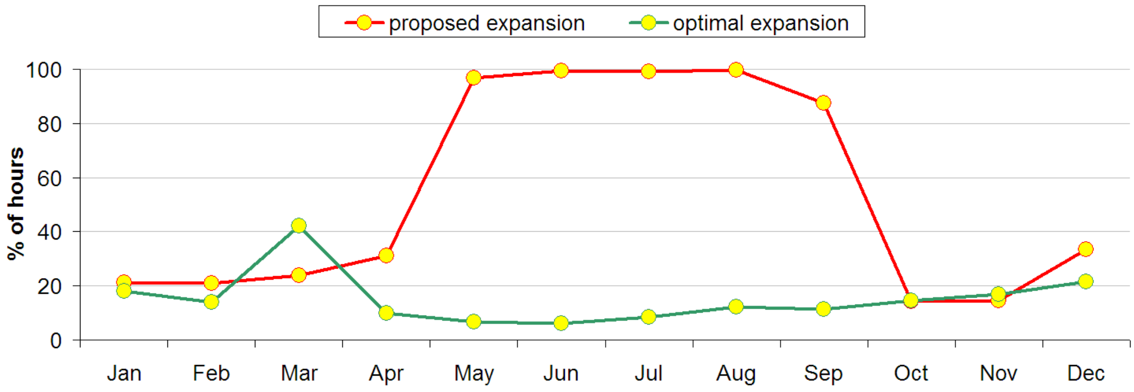

Figure 78: Percentages of congested hours in the France – Spain interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

France (FR) – Germany and Denmark West (DE)

- *"proposed expansion"*: congestion situation is particularly critical between October and April, while no congestion occurs between May and September;
- *"optimal expansion"*: congestion dramatically decreases in the critical period, with percentages almost always below 30%.

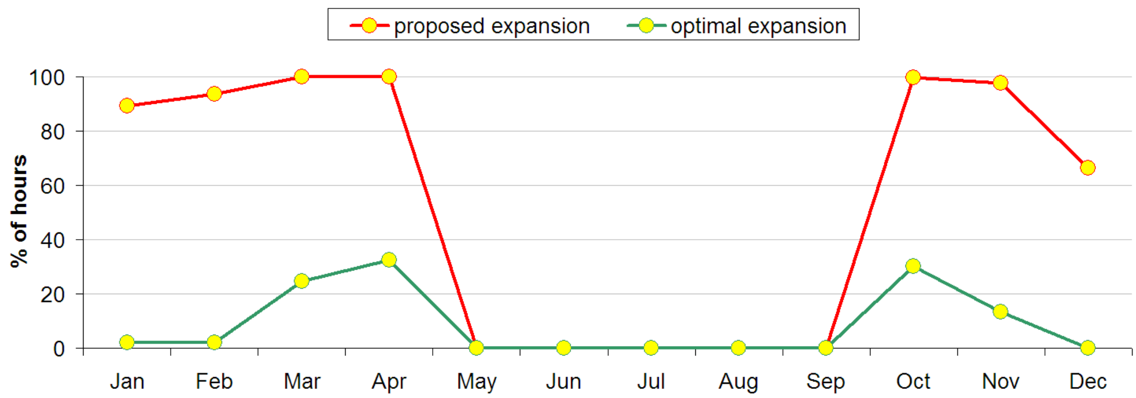

Figure 79: Percentages of congested hours in the France – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Poland (PL) – Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is almost always completely saturated throughout the entire year;
- *"optimal expansion"*: congestion significantly decreases, with percentages almost always below 60%.

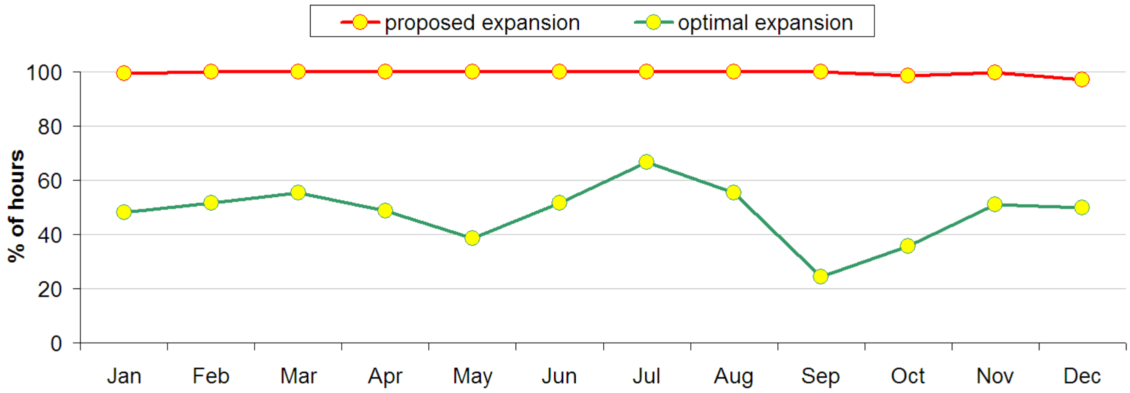

Figure 80: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Romania (RO) – Bulgaria (BG)

- *"proposed expansion"*: the interconnection is almost completely saturated in summer and in the rest of the year percentages are almost always over 60%;
- *"optimal expansion"*: congestion dramatically decreases, with very low percentages except in July and in August (51% and 35%, respectively).

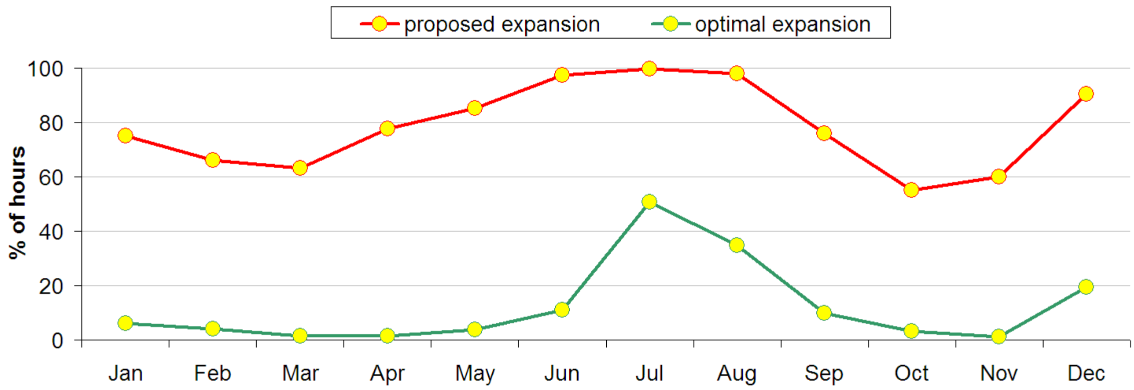

Figure 81: Percentages of congested hours in the Romania – Bulgaria interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

France (FR) – Republic of Ireland (IE)

- *"proposed expansion"*: the interconnection is highly congested throughout the year, and especially between April and August;
- *"optimal expansion"*: congestion dramatically decreases, with very low percentages between September and April, while between May and August they are in the range 40%÷60%.

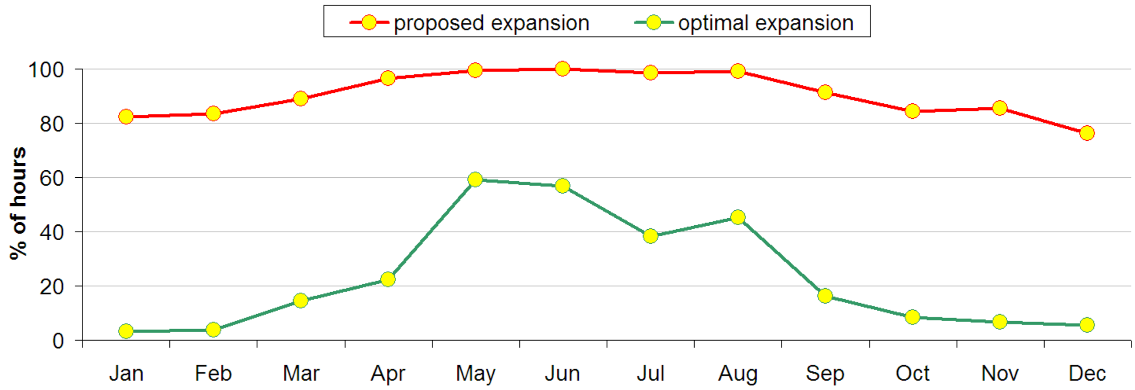

Figure 82: Percentages of congested hours in the France – Ireland interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

United Kingdom (UK) – France (FR)

- *"proposed expansion"*: the interconnection is highly congested especially in spring and in summer;
- *"optimal expansion"*: congestion decreases, but it remains in the range 60%÷80% throughout the year.

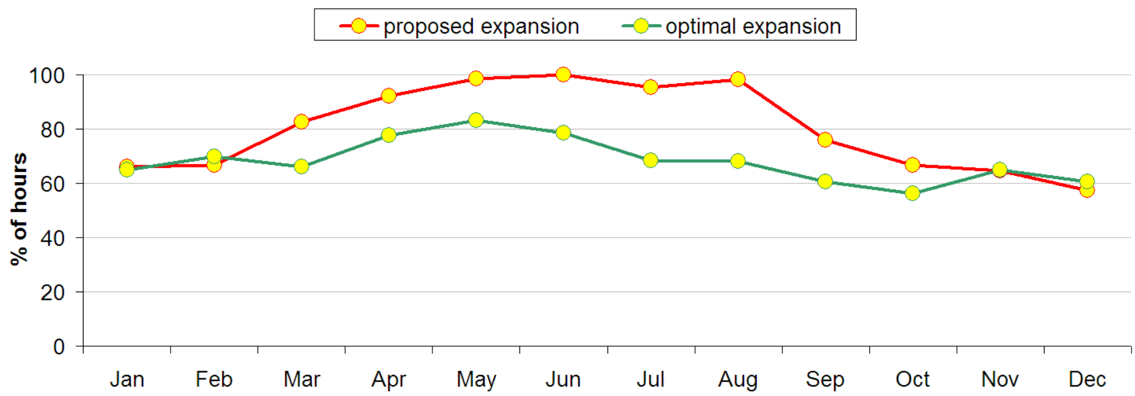

Figure 83: Percentages of congested hours in the United Kingdom – France interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Norway (NO) – Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is almost always completely saturated;
- *"optimal expansion"*: congestion significantly decreases between November and January and between March and May.

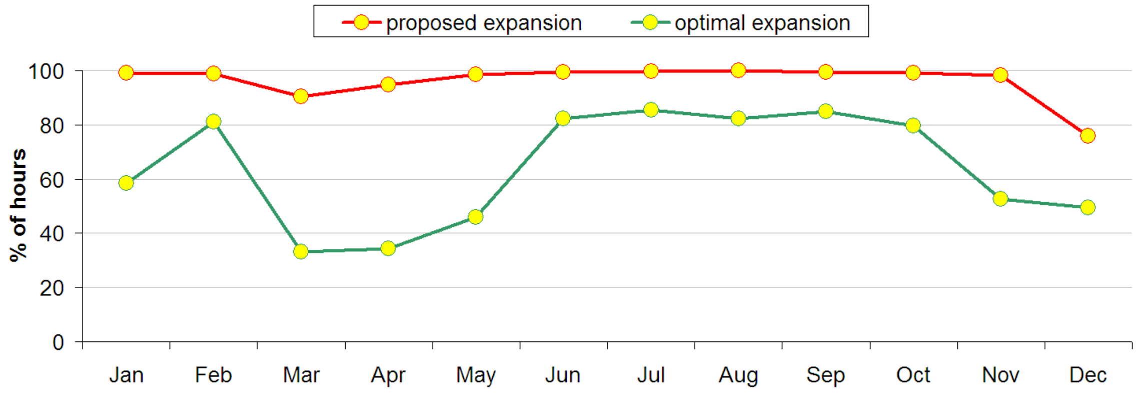

Figure 84: Percentages of congested hours in the Norway – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Sweden and Denmark East (SE) – Germany and Denmark West (DE)

- *"proposed expansion"*: the interconnection is highly congested between June and October and in February;
- *"optimal expansion"*: congestion significantly decreases in the most critical period, but increases in March and in April, that are not critical in the "proposed expansion" scenario.

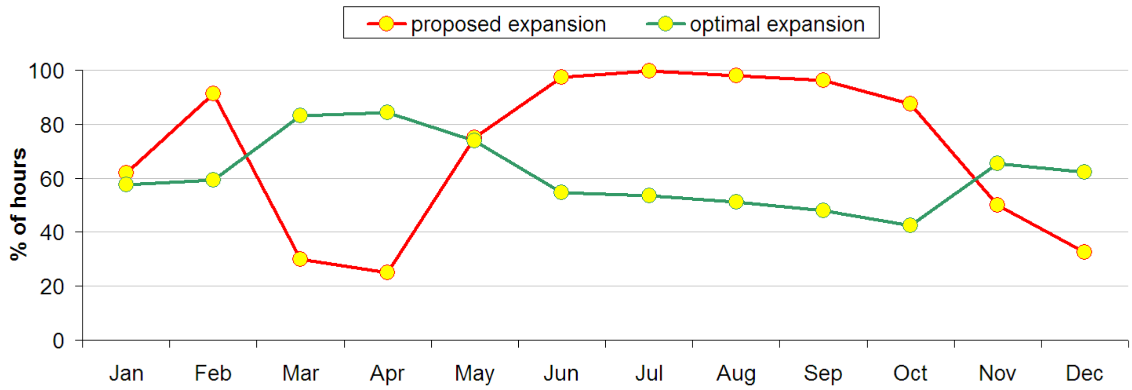

Figure 85: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Poland (PL) – Sweden and Denmark East (SE)

- *"proposed expansion"*: the interconnection is almost completely saturated throughout the entire year;
- *"optimal expansion"*: congestion decreases especially in summer, but it remains critical in the rest of the year.

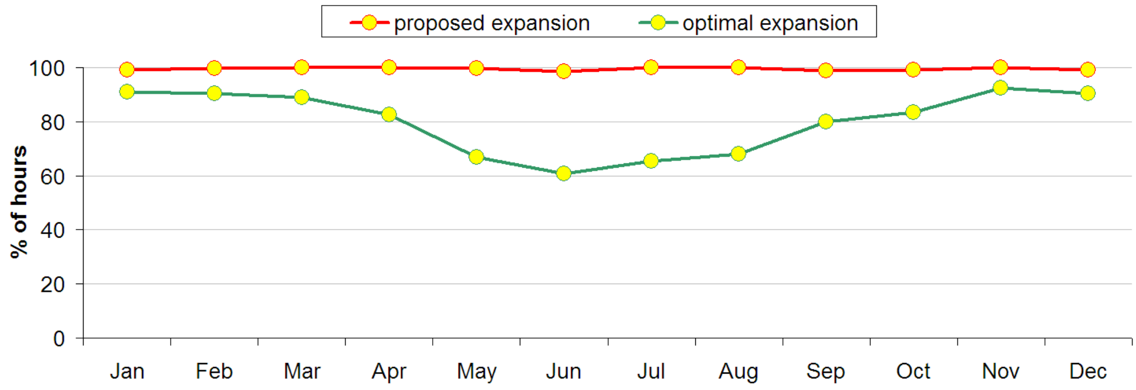

Figure 86: Percentages of congested hours in the Poland – Sweden and Denmark East interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Poland (PL) – Baltic countries (BT)

- *"proposed expansion"*: the interconnection is almost completely saturated throughout the entire year;
- *"optimal expansion"*: congestion decreases especially in summer, but it remains critical in the rest of the year.

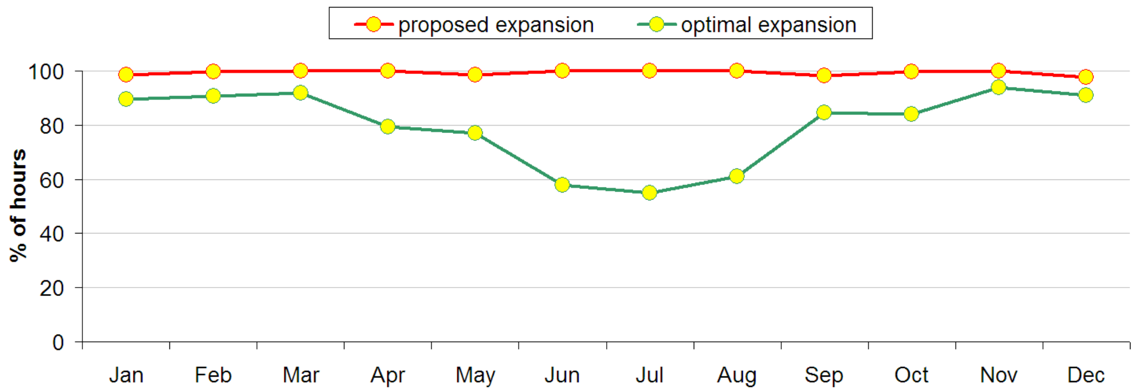

Figure 87: Percentages of congested hours in the Poland – Baltic countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Finland (FI) – Baltic countries (BT)

- *"proposed expansion"*: the interconnection is almost completely saturated throughout the entire year;
- *"optimal expansion"*: congestion decreases especially in winter and in spring, but it remains critical in the rest of the year.

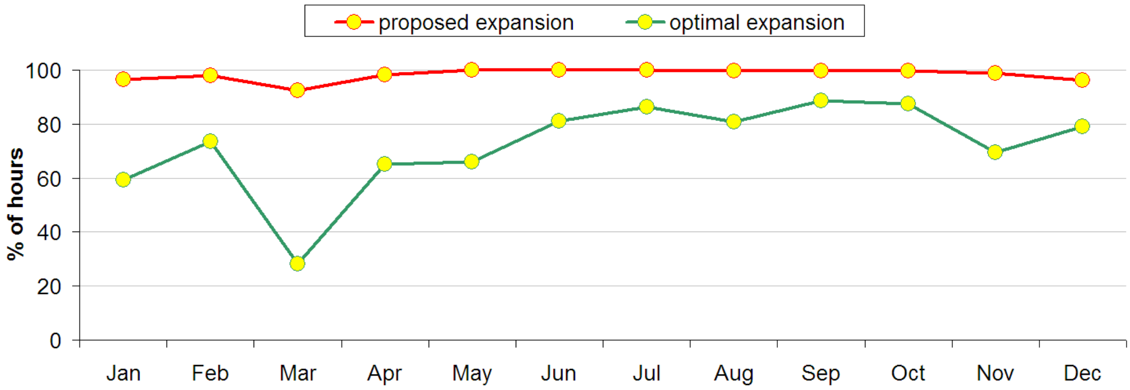

Figure 88: Percentages of congested hours in the Finland – Baltic countries interconnection in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios.

Impact on electricity prices

Similarly to paragraph 0, in Figure 55 we report the differences between the annual average zonal prices in the "optimal expansion" and in the "proposed expansion" scenarios.

It can be noted that the main "winners" in this scenario are Germany, Baltic countries, Norway, Sweden, Finland and The Netherlands while the main "losers" are Romania, Ukraine West, France, Poland, Bulgaria, and Greece.

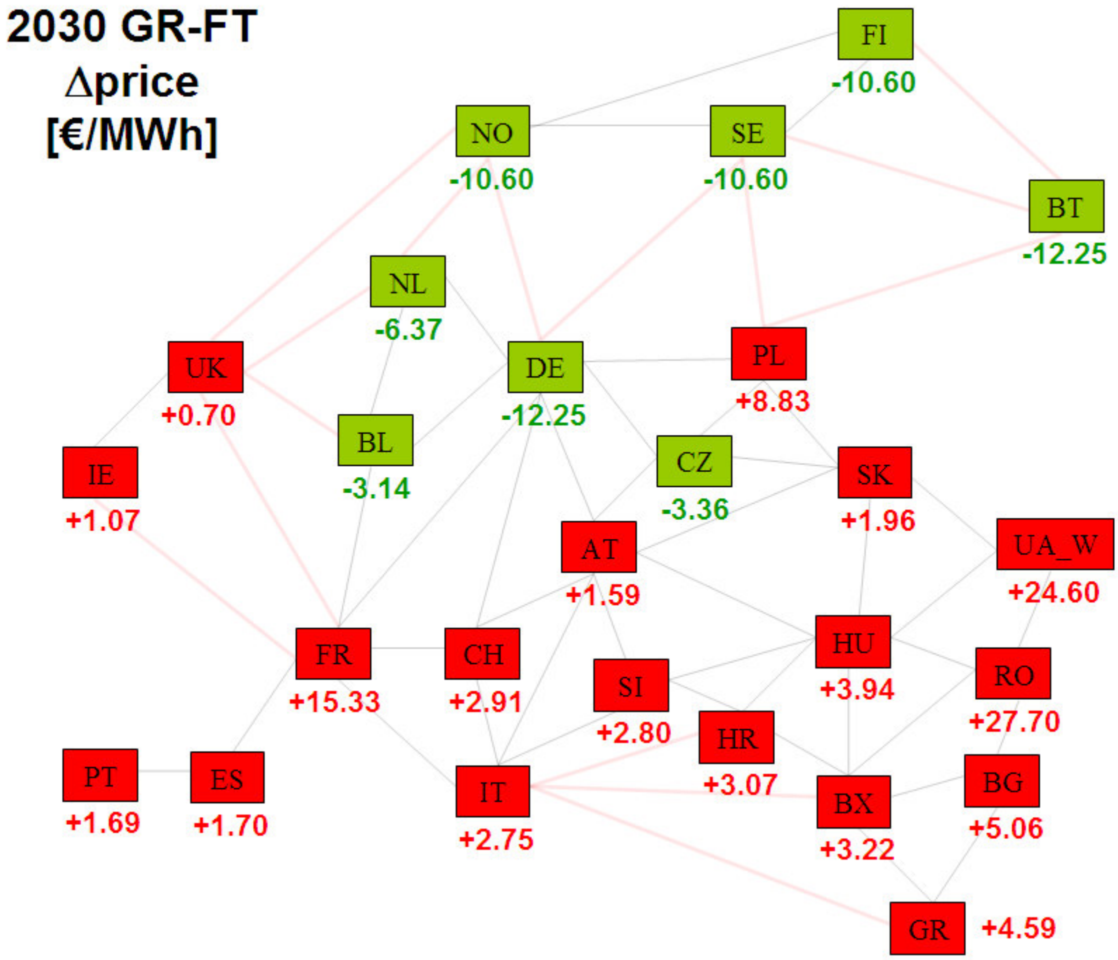

Figure 89: Zonal price differences between the "optimal expansion" and the "proposed expansion" 2030 GR-FT scenarios.

Impact on fuel consumption

In the following Table 140, a comparison between electricity production by different fuels of non-CHP power plants in the "proposed expansion" and in the "optimal expansion" scenarios is reported.

The consequence of the "optimal expansion" (that reduces network constraints) is an increase of production by power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology) at the expense of the more emissive ones (hard coal, lignite and fuel oil). In fact, the "Global Regime with Full Trade" scenario is characterized by a quite high CO_2 emissions value (about 63 €/tCO_2: see paragraph 0).

In Table 141 the corresponding data in terms of fuel consumption are reported: the greater use of less emissive generation technologies slightly decreases total fuel consumption.

Fuel	**"proposed expansion" [GWh]**	**"optimal expansion" [GWh]**	**Δ [GWh]**	**Δ%**
Nuclear	981360	989951	8591	0.9
Hard coal	371722	364287	-7435	-2.0
Lignite	70723	54427	-16296	-23.0
Natural gas	344337	345805	1468	0.4
Fuel oil	19	0	-19	-100
Coal CCS	293031	302181	9150	3.1
Gas CCS	86879	91175	4296	4.9

Table 140: Comparison between electricity generation by different fuels of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios (GWh).

Fuel	**"proposed expansion" [PJ]**	**"optimal expansion" [PJ]**	**Δ [PJ]**	**Δ%**
Nuclear	10060.6	10151.7	91.1	0.9
Hard coal	3059.8	2886.3	-173.5	-5.7
Lignite	729.3	562.3	-167	-22.9
Natural gas	2376.1	2353.8	-22.3	-0.9
Fuel oil	1.3	0	-1.3	-100
Coal CCS	2393.0	2467.8	74.8	3.1
Gas CCS	568.7	596.8	28.1	4.9
Total	**19188.8**	**19018.7**	**-170.1**	**-0.9**

Table 141: Comparison between fuel consumption of non-CHP plants in the "proposed expansion" and in the "optimal expansion" 2030 GR-FT scenarios (PJ).

Impact on CO_2 emissions

In the following Table 142 a comparison between CO_2 emissions by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

Due to substitution of more emissive generation with less emissive one, overall CO_2 emissions significantly decrease, by about **33.6 $MtCO_2$**.

Fuel	“proposed expansion” [$MtCO_2$]	“optimal expansion” [$MtCO_2$]	Δ [$MtCO_2$]	Δ%
Hard coal	287.62	271.31	-16.31	-5.7
Lignite	73.72	56.84	-16.88	-22.9
Natural gas	133.06	131.84	-1.22	-0.9
Fuel oil	0.10	0	-0.1	-100
Coal CCS	22.49	23.20	0.71	3.2
Gas CCS	4.78	5.01	0.23	4.8
Total	**521.77**	**488.2**	**-33.57**	**-6.4**

Table 142: Comparison between CO_2 emissions of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios ($MtCO_2$).

Impact on costs

In the following
Table 143 a comparison between each cost item of the modelled power system in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

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

Cost item	“proposed expansion” [M€]	“optimal expansion” [M€]	Δ [M€]	Δ%
Fuel consumption	35445	35196	-249	-0.7
CO_2 emissions allowances	33006	30882	-2124	-6.4
Investments / O&M AC lines	-	216	216	-
Investments / O&M DC lines	-	241	241	-
TOTAL COSTS	**68451**	**66535**	**-1916**	**-2.8**

Table 143: Comparison between costs of the modeled power system in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios (M€).

Comparison among scenarios

First of all, as far as security of supply is concerned, it must be noted that in no one of the considered scenarios there is Energy Not Supplied (ENS): this means that the modelled generation / transmission system is always able to supply the load.

As for cross-border network expansions, in the following Table 144, the first five interconnections with the greatest increases of transmission capacity in the “optimal expansion” w.r.t. the “proposed expansion” scenarios are reported (see also Table 124, Table 129, Table 134 and Table 139).

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

Table 144: Interconnections with the greatest increases of transmission capacity in the “optimal expansion” w.r.t. the “proposed expansion” scenarios (interconnections that occur in different scenarios are highlighted with the same color).

It can be noted that the interconnections between **France and Spain** and between **France and Germany** are among the most expanded both in the 2015 and in the 2030 scenarios.

Moreover, as far as 2030 scenarios are concerned, the interconnections between **Slovak Republic and Ukraine West** and between **Balkan countries and Romania** are among the most expanded, too.

Other interconnections that are often significantly expanded in the optimal w.r.t. the proposed expansion scenarios are the ones between **Germany and Norway**, **Germany and Sweden**, **Sweden and Poland, Romania and Ukraine West, Finland and Baltic countries** and **Poland and Baltic countries**.

This means that, for the aforementioned interconnections, the proposed expansion levels seem to be far from the optimal ones under the assumptions of the considered scenarios.

Concerning the electricity price differences between the “optimal expansion” and the “proposed expansion” scenarios, the main 2015 “winner” (i.e. countries where the average price decreases) countries (i.e. **Poland**, **Portugal** and **Spain**) do not maintain their positions in the 2030 scenarios, where the main “winners” are **Germany**¸ **Baltic countries**, **The Netherlands** and **Belgium**,

together with **Norway**, **Sweden** and **Finland** especially in the two most environmentally friendly scenarios (EA and GR-FT).
On the other hand, the main "losers" (i.e. countries where the average price increases) are most often **Romania**, **Poland**, **Bulgaria**, **Ukraine West**, **France** and **Greece**.

In the following Table 145, the variations of fuel consumption of non-CHP plants in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios are reported.
It can be noted that in the 2015 and in the MT 2030 scenarios, characterized by relatively low CO_2 emissions values (respectively, about 13 and 24 €/MtCO_2) the "optimal expansion" causes an overall increase of fuel consumption, by reducing natural gas and increasing coal and lignite (as well as nuclear in 2015) consumptions.
On the other hand, in the two most environmentally friendly scenarios (EA 2030 and GR-FT 2030), where CO_2 emissions values are quite high (respectively 90 and 63 €/MtCO_2), the "optimal expansion" causes an overall decrease of fuel consumption, by increasing consumption of power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology), but significantly reducing consumption of the more emissive ones (hard coal and lignite).
In any case, the variations of fuel consumption between the optimal and the proposed expansion scenarios are not very high, ranging from +1.9 to -4.4 Mtoe.

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

Table 145: Variations of fuel consumption of non-CHP plants in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios.

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

Table 146: Variations of CO_2 emissions of non-CHP plants in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios.

The aforementioned fuel consumption data have a direct consequence on the variations of CO_2 emissions, reported in Table 146. It can be noted that, while variation of the 2015 scenario is almost negligible (due to the increase of nuclear production that compensates the greater hard coal and lignite productions), the MT 2030 scenario is characterized by a slight increase of CO_2 emissions. On the contrary, the more environmentally friendly EA and GR-FT 2030 scenarios show more significant CO_2 emissions reductions.

As for the variations of the costs of the modeled power system, reported in Table 147, it can be noted that in the two scenarios (2015 and MT 2030) characterized by low CO_2 emissions values the main component of cost reduction is fuel cost, while in the two more environmentally friendly scenarios (EA and GR-FT 2030) the main component is by far the reduction of costs related to CO_2 emissions allowances.
In this latter case, cost savings due to the "optimal expansion" w.r.t. the "proposed expansion" can be significant, ranging from 1.9 to 4.4 billions Euros.

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

Table 147: Variations of the costs of the modeled power system in the "optimal expansion" w.r.t. the "proposed expansion" in the different scenarios.

Step 5: remedies assessment

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

Short-term remedies

- *Dispatch more expensive generation in the importing countries*

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

- *Reduce demand*

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

Long-term remedies

- *Increase cross-border transmission capacity*

Needless to say, the main remedy to a non optimal development of the European cross-border electricity transmission network is to invest in new interconnections, so that the reduction of bottlenecks makes easier to transport cheaper energy where it is needed, increasing security of supply, but also allowing for a more optimized operation of the generation set and for an increase of competition in the market, with significant economic benefits.
This remedy is of course not so easy to implement, neither by TSOs, nor by private investors interested in merchant lines projects. In fact, such investments are typically affected by several uncertainties (see [17]), mainly due to:

- o complex legal and regulatory contexts, especially for permitting procedures (see [44]), stemming from a multitude of different authorities, with different administrative levels (European, national, local) that may differ from one country to another and that may have different priorities;
- o the lack of social acceptance that severely delays or jeopardizes the realisation of such projects;
- o due to the long-term time horizon that characterizes network projects, the inherent uncertainty in predicting the future location and amount of generation and consumption, as well as the changes over time in the way electricity is generated and consumed, also due to the impact of different policies (and of different policy implementation options) such as energy demand reduction and efficiency, renewable energy sources integration, CO_2 emissions reduction, decommissioning of polluting units, etc.

To reduce such uncertainties[36]:

- o the establishment of the *Agency for the Cooperation of Energy Regulators – ACER* foreseen by the 3rd Energy Package (see [45]) should be a significant step towards a more harmonized regulatory framework at the European level;
- o as for the several other authorities involved in the permitting procedures, ENTSO-E in [2] states that *"competing priorities are one of the major sources of slow development processes, requiring guidelines with a strong influence on national and also local governments in a way that all involved stakeholders are able to unambiguously prioritise projects"*;
- o to speed-up permitting procedures, ENTSO-E in [44] provides the following recommendations:
  - ⇨ *The public interest of important electricity infrastructure projects shall be stated in law. The need for the development of these projects shall be stated "objectively" (e.g. in a list of high priority projects) and therefore the justification does not always need to be argued by TSOs during the proceedings.*
  - ⇨ *There should be clear and explicit linkage between TEN-E projects and national law (recognition of TEN-E projects in national law). The public interest of TEN-E projects should a priori be recognised by their definition.*
  - ⇨ *Authorisation procedures for strategic infrastructure projects should be centralised at one (national) level.*
  - ⇨ *The number of permits required should be reduced by creating an integrated procedure for infrastructure projects or for projects subject to an environmental impact assessment including the connection to substations with the same requirements in all regions of the country.*

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[36] The reported recommendations are to be further deepened within the EC REALISEGRID project [18].

- ⇨ *The result of the procedure for transmission lines and for substations should be a building permit with the right of way that allows construction to start immediately.*
- ⇨ *There should be simplified procedures with a shorter duration for the upgrading of existing lines (e.g. to a higher voltage).*
- ⇨ *There should be effective and compulsory time limits to grant the TSOs legal certainty as regards the timely completion of permitting procedures (including the closing-off of submissions of allegedly new statements and evidence opposing the construction of an infrastructure project).*
- ⇨ *There should be a clear definition of what documents are needed during the authorisation procedures (e.g. during EIA).*
- ⇨ *Effective consultation mechanisms are vital especially at the very beginning of a project. Duplication of such time-consuming mechanisms shall be avoided if their purpose can be achieved through only one single consultation, otherwise there must be a coordination between different consultations (e.g. between the Environmental Evaluation for the whole Grid Plan and the Environmental Evaluation for the single project of the Grid Plan).*
- ⇨ *A Region should not have the right to stop strategic national and cross border infrastructure: it should be stated that the final permitting decision should remain with the National Authorities.*
- ⇨ *It should still be possible to build necessary infrastructure projects in protected areas (e.g. Natura 2000) if the environmental effects of these projects can be mitigated and compensation measures are taken.*
- ⇨ *There should be a simplified procedure for the assessment of the effects on the environment of certain Plans approved on annual basis (e.g. Grid Transmission Plans).*
- ⇨ *It should be possible to reserve so-called "infrastructure corridors" for high priority infrastructure projects.*
- ⇨ *Common agreement with involved parties concerning corridors and in particular common dedicated corridors for different types of infrastructure (pipelines, highways, railways, high voltage lines, etc.) would be desirable.*
- ⇨ *The relevant authorities should define new infrastructure corridors for high priority infrastructure projects.*
- ⇨ *For new infrastructure and/or upgrading of the existing infrastructure existing routes should preferably be used.*
- ⇨ *Sufficient and specialized manpower is necessary to deal with infrastructure projects in an effective and timely manner in the TSOs as also in external resources (e.g. authorities).*

- as for the lack of social acceptance, a correct and complete information provided to the involved populations by all the concerned bodies is of paramount importance; in particular, concerns about the environmental impact of the projects (e.g. impact on natural areas, visual impact, alleged health effects of electromagnetic fields, etc.) must be discussed on a clear and sound scientific basis, in order to allow for an informed comparison between such "cons" and the "pros" of the projects;
- as for the "pros", the public benefits of the projects must be clearly stated and quantified, especially from the security of supply, from the sustainability (in particular when renewable energy flows are involved) and from the economic points of view; also, the strategic importance that characterizes cross-border transmission projects must be highlighted with the support of the highest political decision levels;
- the economic side of the problem is very important to gain consensus among the involved populations: they must know that the realization of the projects will reduce their electricity bills (either by imports of cheaper energy or by direct compensations), otherwise the *nimby* attitude would be their first and easiest choice;
- as for the uncertainties concerning the future developments of generation and demand, they can be effectively tackled by carrying out adequate *scenario analyses*, just like it has been done in the present study on the basis of POLES scenarios; this approach is supported also by ENTSO-E that in [2] states that *"scenario analyses at national, regional and pan-European levels are key elements in order to decide on grid extensions and to adequately assist political reasoning"* taking into account *"fuel prices, economic and monetary conditions, geopolitical developments, meteorological conditions, technological breakthroughs, market mechanisms, regulatory and legal frameworks"*.

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

Again, this is exactly what has been done in the present study, following an approach supported also by ENTSO-E, that in its recent *"Research and Development Plan" [46]* foresees the development of *"Advanced tools for analyzing the pan-European network expansion options according to energy scenarios for Europe (i.e. expansion optima that must be searched to maximize European welfare)"*, specifying that optima are to be searched at EU level and no longer at national level.

- *Increase energy efficiency in electricity consumption*

A greater end use electric energy efficiency would entail a demand reduction that would decrease the criticalities related to the impossibility to import cheaper energy.

EU is supporting this process with some Directives (e.g. 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 EU countries are implementing them within the framework of their National Energy Efficiency Action Plans (see also [14]).

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

Step 6: how remedies should be financed / paid for

Short-term remedies

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

Long-term remedies

Investments in new cross-border transmission capacity can be carried out either by TSOs or by private investors building the so-called "merchant lines".
Investments by TSOs are remunerated with a fair return through transmission tariffs defined by regulators.
Due to the strategic importance of cross-border lines, regulators may acknowledge to such projects a rate of return higher than for normal transmission lines: for example, in Italy, investments that increase cross-border Net Transfer Capacity are acknowledged an increase of the rate of return of 3% for 12 years (see [47]).
As for investments in "merchant lines", they are basically remunerated by electricity price differentials between the markets they interconnect.
In fact, due to Regulations no. 1228/2003 [48] and 714/2009 [49], such projects may be exempted for a limited period of time (by the regulatory authorities of the Member States concerned) from Third Party Access requirement, established by Directive 2003/54/EC [50] and confirmed by Directive 2009/72/EC [51]. Such exemption may cover all or part of the capacity of the new interconnector, or of the existing interconnector with significantly increased capacity.
As for financing issues, apart from banks, a key role is often played by the European Investment Bank (EIB), especially concerning the Trans-European Energy Networks (TENs) projects.
EIB's contribution typically does not exceed 50% of the total investment cost, in order to capitalize on its first-rate lending terms to attract other sources of financing. This enables the borrowers to set up a diversified finance plan in partnership with other financial institutions and banks. As for the

borrowers, they can be public authorities or private entities, including special purpose vehicles, as well as banks and financial institutions.

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

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

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

Conclusions

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

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

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

The impact assessment of the considered “threat” has been carried out by developing and running a model of the European power system (based on the MTSIM simulator, developed by ERSE) and has been focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO_2 emissions).

In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal (least cost) developments determined by MTSIM. The reference years considered in the study are 2015 and 2030.

The reference framework within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security: *Muddling Through (MT)*, *Europe Alone (EA)* and *Global Regime with Full Trade (GR-FT)*.

The results of the simulations show that in no one of the considered scenarios there is Energy Not Supplied (ENS), therefore there are no problems in terms of security of supply due to insufficient cross-border transmission capacity or to available generation capacity.

Moreover, the proposed cross-border network expansions are clearly sub-optimal: in the considered scenarios, for example, the interconnections between France and Germany, France and Spain, Slovak Republic and Ukraine West, Balkan countries and Romania, as well as several others, in the “optimal expansion” case are expanded significantly more than in the “proposed expansion” case.

In the “optimal expansion”, the countries where the average electricity price decreases (w.r.t. the “proposed expansion” case) are Poland, Portugal and Spain in the 2015 scenario, while in the 2030 scenarios they are replaced by Germany¸ Baltic countries, The Netherlands and Belgium, together with Norway, Sweden and Finland especially in the two most environmentally friendly scenarios (EA and GR-FT).

On the other hand, the countries where the average price increases are most often Romania, Poland, Bulgaria, Ukraine West, France and Greece.

It can also be noted that in the 2015 and in the MT 2030 scenarios, characterized by relatively low CO_2 emissions values (respectively, about 13 and 24 €/MtCO_2) the "optimal expansion" causes an overall increase of fuel consumption, by reducing natural gas and increasing coal and lignite (as well as nuclear in 2015) consumptions.

On the other hand, in the two most environmentally friendly scenarios (EA 2030 and GR-FT 2030), where CO_2 emissions values are quite high (respectively 90 and 63 €/MtCO_2), the "optimal expansion" causes an overall decrease of fuel consumption, by increasing consumption of power plants characterized by the lowest CO_2 emission rates (nuclear, natural gas and plants equipped with CCS technology), but significantly reducing consumption of the more emissive ones (hard coal and lignite).

In any case, the variations of fuel consumption between the optimal and the proposed expansion scenarios are not very high, ranging from +1.9 to -4.4 Mtoe.

The aforementioned fuel consumption data have a direct consequence on the variations of CO_2 emissions: while variation of the 2015 scenario is almost negligible (due to the increase of nuclear production that compensates the greater hard coal and lignite productions), the MT 2030 scenario is characterized by a slight increase of CO_2 emissions (about 17 MtCO_2). On the contrary, the more environmentally friendly EA and GR-FT 2030 scenarios show more significant CO_2 emissions reductions (respectively, about 57 and 34 MtCO_2).

As for the variations of the costs of the modeled power system, it can be noted that in the two scenarios (2015 and MT 2030) characterized by low CO_2 emissions values the main component of cost reduction is fuel cost, while in the two more environmentally friendly scenarios (EA and GR-FT 2030) the main component is by far the reduction of costs related to CO_2 emissions allowances.

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

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

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

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

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

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

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

APPENDIX I

MTSIM MATRIX: TRADITIONAL MODALITY

	P(G1,t1)	P(G2,t1)	P(GN,t1)	ENP(Z1,t1)	ENP(ZN,t1)	EIE(Z1,t1)	EIE(ZN,t1)	V(H1,t1)	V(H2,t1)	V(HN,t1)	W(H1,t1)	W(H2,t1)	W(HN,t1)
4(t1,L1)	$PDTF_{L1,Z(G1)}$	$PDTF_{L1,Z(G2)}$	$PDTF_{L1,Z(GN)}$	$PDTF_{L1,Z1}$	$PDTF_{L1,ZN}$	$-PDTF_{L1,Z1}$	$-PDTF_{L1,ZN}$	0	0	0	0	0	0
4(t1,L2)	$PDTF_{L2,Z(G1)}$	$PDTF_{L2,Z(G2)}$	$PDTF_{L2,Z(GN)}$	$PDTF_{L2,Z1}$	$PDTF_{L2,ZN}$	$-PDTF_{L2,Z1}$	$-PDTF_{L2,ZN}$	0	0	0	0	0	0
4(t1,LN)	$PDTF_{LN,Z(G1)}$	$PDTF_{LN,Z(G2)}$	$PDTF_{LN,Z(GN)}$	$PDTF_{LN,Z1}$	$PDTF_{LN,ZN}$	$-PDTF_{LN,Z1}$	$-PDTF_{LN,ZN}$	0	0	0	0	0	0
5(t1)	1	1	1	1	1	-1	-1	0	0	0	0	0	0
3(t1,H1)	0	0	0	0	0	0	0	-1	0	0	$-\Delta T_1$	0	0
3(t1,H2)	0	0	0	0	0	0	0	0	-1	0	0	$-\Delta T_1$	0
3(t1,HN)	0	0	0	0	0	0	0	0	0	-1	0	0	$-\Delta T_1$
3(t2,H1)	0	0	0	0	0	0	0	1	0	0	0	0	0
3(t2,H2)	0	0	0	0	0	0	0	0	1	0	0	0	0
3(t2,HN)	0	0	0	0	0	0	0	0	0	1	0	0	0
1	$K\Delta T_t$ gen. e tempi rilevanti			0	0	0	0	0	0	0	0	0	0
2	$\pi_{gf} B_{1gtf} \Delta T_t$ gen. e tempi rilevanti			0	0	0	0	0	0	0	0	0	0
3	$\pi_{gf} f_{CO_2 fg} B_{1gtf} \Delta T_t$ gen. e tempi rilevanti			0	0	0	0	0	0	0	0	0	0
6				0	0	0	0	0	0	0	0	0	0
F	$c_{G1,t1}\Delta T_1$	$c_{G2,t1}\Delta T_1$	$c_{GN,t1}\Delta T_1$	$VOLL\,\Delta T_1$	$VOLL\,\Delta T_1$	$VOEE\,\Delta T_1$	$VOEE\,\Delta T_1$	0	0	0	0	0	0
lb	P_{min}(G1,t1)	P_{min}(G2,t1)	P_{min}(GN,t1)	0	0	0	0	V_{min}(H1,t1)	V_{min}(H2,t1)	V_{min}(HN,t1)	0	0	0
ub	P_{max}(G1,t1)	P_{max}(G2,t1)	P_{max}(GN,t1)	Inf	Inf	Inf	Inf	V_{max}(H1,t1)	V_{max}(H2,t1)	V_{max}(HN,t1)	W_{max}(H1,t1)	W_{max}(H2,t1)	W_{max}(HN,t1)

$$-\sum_{\Phi i} \pi_{\Phi i(g)} f_{CO2\,\Phi i(g)} B_{1gt\Phi i} \Delta T_t$$

P(H1,t1)	P(H2,t1)	P(HN,t1)	Q(H1,t1)	Q(H2,t1)	Q(HN,t1)	X(H1,t1)	XH2,t1)	X(HN,t1)	Y(H1,t1)	Y(H2,t1)	Y(HN,t1)
$PDTF_{L1,Z(H1)}$	$PDTF_{L1,Z(H2)}$	$PDTF_{L1,Z(HN)}$	$-PDTF_{L1,Z(H1)}$	$-PDTF_{L1,Z(H2)}$	$-PDTF_{L1,Z(HN)}$	0	0	0	0	0	0
$PDTF_{L2,Z(H1)}$	$PDTF_{L2,Z(H2)}$	$PDTF_{L2,Z(HN)}$	$-PDTF_{L2,Z(H1)}$	$-PDTF_{L2,Z(H2)}$	$-PDTF_{L2,Z(HN)}$	0	0	0	0	0	0
$PDTF_{LN,Z(H1)}$	$PDTF_{LN,Z(H2)}$	$PDTF_{LN,Z(HN)}$	$-PDTF_{LN,Z(H1)}$	$-PDTF_{LN,Z(H2)}$	$-PDTF_{LN,Z(HN)}$	0	0	0	0	0	0
1	1	1	-1	-1	-1	0	0	0	0	0	0
$-\frac{\Delta T_1}{\lambda_{H1}}$	0	0	$\frac{\eta_{H1}\Delta T_1}{\lambda_{H1}}$	0	0	1	0	0	-1	0	0
0	$-\frac{\Delta T_1}{\lambda_{H2}}$	0	0	$\frac{\eta_{H2}\Delta T_1}{\lambda_{H2}}$	0	0	1	0	0	-1	0
0	0	$-\frac{\Delta T_1}{\lambda_{HN}}$	0	0	$\frac{\eta_{HN}\Delta T_1}{\lambda_{HN}}$	0	0	1	0	0	-1
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	10^6	10^6	10^6	10^6	10^6	10^6
0	0	0	0	0	0	0	0	0	0	0	0
P_{max}(H1,t1)	P_{max}(H2,t1)	P_{max}(HN,t1)	Q_{max}(H1,t1)	Q_{max}(H2,t1)	Q_{max}(HN,t1)	Inf	Inf	Inf	Inf	Inf	Inf

I(L1,t1)	I(L2,t1)	I(LN,t1)	EGT*	WGT*	Emiss	GCBuyET	GCBuyCDM	MargCO2	beq
-1	0	0	0	0	0	0	0	0	$\sum_z PTDF_{L1,z} C_{z,t1}$
0	-1	0	0	0	0	0	0	0	$\sum_z PTDF_{L2,z} C_{z,t1}$
0	0	-1	0	0	0	0	0	0	$\sum_z PTDF_{LN,z} C_{z,t1}$
0	0	0	0	0	0	0	0	0	$\sum_z C_{z,t1}$
0	0	0	0	0	0	0	0	0	$-n_{H1,t1}\Delta T_1 - V_{0H1}$
0	0	0	0	0	0	0	0	0	$-n_{H2,t1}\Delta T_1 - V_{0H2}$
0	0	0	0	0	0	0	0	0	$-n_{HN,t1}\Delta T_1 - V_{0HN}$
0	0	0	0	0	0	0	0	0	$-n_{H1,t2}\Delta T_2$
0	0	0	0	0	0	0	0	0	$-n_{H2,t2}\Delta T_2$
0	0	0	0	0	0	0	0	0	$-n_{HN,t2}\Delta T_2$
0	0	0	-1	0	0	0	0	0	0
0	0	0	0	-1	0	0	0	0	$-\sum_{T^*}\sum_{\Gamma}\pi_{gf}B_{0gtf}s_{gt}\Delta T_t$
0	0	0	0	0	-1	0	0	0	$\sum_{T^*}\sum_{\Gamma}\sum_{\Phi i(g)}\pi_{\Phi i(g)} f_{CO2\Phi i(g)} B_{0gt\Phi t} s_{gt}\Delta T_t - M$
0	0	0	0	0	0	1	1	-1	$\sum_{t}\sum_{g}\sum_{\Phi i(g)}\pi_{\Phi i(g)} f_{CO2\Phi i(g)} B_{0gt\Phi t} s_{gt}\Delta T_t - \overline{PCO2}_{Italy}$

I(L1,t1)	I(L2,t1)	I(LN,t1)	EGT*	WGT*	Emiss	GCBuyET	GCBuyCDM	MargCO2
0	0	0	0	0	0	c_{ET}	c_{CDM}	0
$I_{min}(L1,t1)$	$I_{min}(L2,t1)$	$I_{min}(LN,t1)$	EGT^*_{min}	WGT^*_{min}	0	ET_{min}	CDM_{min}	0
$I_{max}(L1,t1)$	$I_{max}(L2,t1)$	$I_{max}(LN,t1)$	EGT^*_{max}	WGT^*_{max}	*M*	Et_{max}	CDM_{max}	Inf.

In realtà limitato dall'equazione che lo definisce

MTSIM MATRIX: PLANNING MODALITY

	P(G1,t1)	P(G2,t1)	P(GN,t1)	ENP(Z1,t1)	ENP(ZN,t1)	EIE(Z1,t1)	EIE(ZN,t1)	V(H1,t1)	V(H2,t1)	V(HN,t1)	W(H1,t1)	W(H2,t1)	W(HN,t1)
4(t1,L1)	$PDTF_{L1,Z(G1)}$	$PDTF_{L1,Z(G2)}$	$PDTF_{L1,Z(GN)}$	$PDTF_{L1,Z1}$	$PDTF_{L1,ZN}$	$-PDTF_{L1,Z1}$	$-PDTF_{L1,ZN}$	0	0	0	0	0	0
4(t1,L2)	$PDTF_{L2,Z(G1)}$	$PDTF_{L2,Z(G2)}$	$PDTF_{L2,Z(GN)}$	$PDTF_{L2,Z1}$	$PDTF_{L2,ZN}$	$-PDTF_{L2,Z1}$	$-PDTF_{L2,ZN}$	0	0	0	0	0	0
4(t1,LN)	$PDTF_{LN,Z(G1)}$	$PDTF_{LN,Z(G2)}$	$PDTF_{LN,Z(GN)}$	$PDTF_{LN,Z1}$	$PDTF_{LN,ZN}$	$-PDTF_{LN,Z1}$	$-PDTF_{LN,ZN}$	0	0	0	0	0	0
5(t1)	1	1	1	1	1	-1	-1	0	0	0	0	0	0
3(t1,H1)	0	0	0	0	0	0	0	-1	0	0	$-\Delta T_1$	0	0
3(t1,H2)	0	0	0	0	0	0	0	0	-1	0	0	$-\Delta T_1$	0
3(t1,HN)	0	0	0	0	0	0	0	0	0	-1	0	0	$-\Delta T_1$
3(t2,H1)	0	0	0	0	0	0	0	1	0	0	0	0	0
3(t2,H2)	0	0	0	0	0	0	0	0	1	0	0	0	0
3(t2,HN)	0	0	0	0	0	0	0	0	0	1	0	0	0
1	$K\Delta T_t$ gen. e tempi rilevanti			0	0	0	0	0	0	0	0	0	0
2	$\pi_{gf} B_{1gtf} \Delta T_t$ gen. e tempi rilevanti			0	0	0	0	0	0	0	0	0	0
3	$\pi_{gf} f_{CO_2 fg} B_{1gtf} \Delta T_t$ gen. e tempi rilevanti			0	0	0	0	0	0	0	0	0	0
6				0	0	0	0	0	0	0	0	0	0

$$\boxed{-\sum_{\Phi i} \pi_{\Phi i(g)} f_{CO2\,\Phi i(g)} B_{1gt\Phi i} \Delta T_t}$$

F	$c_{G1,t1}\Delta T_1$	$c_{G2,t1}\Delta T_1$	$c_{GN,t1}\Delta T_1$	$VOLL\,\Delta T_1$	$VOLL\,\Delta T_1$	$VOEE\,\Delta T_1$	$VOEE\,\Delta T_1$	0	0	0	0	0	0
lb	$P_{min}(G1,t1)$	$P_{min}(G2,t1)$	$P_{min}(GN,t1)$	0	0	0	0	$V_{min}(H1,t1)$	$V_{min}(H2,t1)$	$V_{min}(HN,t1)$	0	0	0
ub	$P_{max}(G1,t1)$	$P_{max}(G2,t1)$	$P_{max}(GN,t1)$	Inf	Inf	Inf	Inf	$V_{max}(H1,t1)$	$V_{max}(H2,t1)$	$V_{max}(HN,t1)$	$W_{max}(H1,t1)$	$W_{max}(H2,t1)$	$W_{max}(HN,t1)$

P(H1,t1)	P(H2,t1)	P(HN,t1)	Q(H1,t1)	Q(H2,t1)	Q(HN,t1)	X(H1,t1)	XH2,t1)	X(HN,t1)	Y(H1,t1)	Y(H2,t1)	Y(HN,t1)
$PDTF_{L1,Z(H1)}$	$PDTF_{L1,Z(H2)}$	$PDTF_{L1,Z(HN)}$	$-PDTF_{L1,Z(H1)}$	$-PDTF_{L1,Z(H2)}$	$-PDTF_{L1,Z(HN)}$	0	0	0	0	0	0
$PDTF_{L2,Z(H1)}$	$PDTF_{L2,Z(H2)}$	$PDTF_{L2,Z(HN)}$	$-PDTF_{L2,Z(H1)}$	$-PDTF_{L2,Z(H2)}$	$-PDTF_{L2,Z(HN)}$	0	0	0	0	0	0
$PDTF_{LN,Z(H1)}$	$PDTF_{LN,Z(H2)}$	$PDTF_{LN,Z(HN)}$	$-PDTF_{LN,Z(H1)}$	$-PDTF_{LN,Z(H2)}$	$-PDTF_{LN,Z(HN)}$	0	0	0	0	0	0
1	1	1	-1	-1	-1	0	0	0	0	0	0
$-\frac{\Delta T_1}{\lambda_{H1}}$	0	0	$\frac{\eta_{H1}\Delta T_1}{\lambda_{H1}}$	0	0	1	0	0	-1	0	0
0	$-\frac{\Delta T_1}{\lambda_{H2}}$	0	0	$\frac{\eta_{H2}\Delta T_1}{\lambda_{H2}}$	0	0	1	0	0	-1	0
0	0	$-\frac{\Delta T_1}{\lambda_{HN}}$	0	0	$\frac{\eta_{HN}\Delta T_1}{\lambda_{HN}}$	0	0	1	0	0	-1
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	10^6	10^6	10^6	10^6	10^6	10^6
0	0	0	0	0	0	0	0	0	0	0	0
P_{max}(H1,t1)	P_{max}(H2,t1)	P_{max}(HN,t1)	Q_{max}(H1,t1)	Q_{max}(H2,t1)	Q_{max}(HN,t1)	Inf	Inf	Inf	Inf	Inf	Inf

I(L1,t1)	I(L2,t1)	I(LN,t1)	EGT*	WGT*	Emiss	GCBuyET	GCBuyCDM	MargCO2	X(L1,t1)	X(L2,t1)	X(LN,t1)
-1	0	0	0	0	0	0	0	0	0	0	0
0	-1	0	0	0	0	0	0	0	0	0	0
0	0	-1	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	-1	0	0	0	0	0	0	0	0
0	0	0	0	-1	0	0	0	0	0	0	0
0	0	0	0	0	-1	0	0	0	0	0	0
0	0	0	0	0	0	1	1	-1	0	0	0

0	0	0	0	0	0	c_{ET}	c_{CDM}	0	K1	K2	KN
-Inf.	-Inf.	-Inf.	EGT^*_{min}	WGT^*_{min}	0	ET_{min}	CDM_{min}	0	0	0	0
Inf.	Inf.	Inf.	EGT^*_{max}	WGT^*_{max}	M	Et_{max}	CDM_{max}	Inf.	X1	X2	XN

In realtà limitato dall'equazione che lo definisce

beq
$\sum_{z} PTDF_{L1,z} C_{z,t1}$
$\sum_{z} PTDF_{L2,z} C_{z,t1}$
$\sum_{z} PTDF_{LN,z} C_{z,t1}$
$\sum_{z} C_{z,t1}$

$-n_{H1,t1}\Delta T_1 - V_{0H1}$
$-n_{H2,t1}\Delta T_1 - V_{0H2}$
$-n_{HN,t1}\Delta T_1 - V_{0HN}$
$-n_{H1,t2}\Delta T_2$
$-n_{H2,t2}\Delta T_2$
$-n_{HN,t2}\Delta T_2$
0
$-\sum_{T^*}\sum_{\Gamma} \pi_{gt} B_{0gtf} s_{gt} \Delta T_t$
$\sum_{T^*}\sum_{\Gamma}\sum_{\Phi i(g)} \pi_{\Phi i(g)} f_{CO2\Phi i(g)} B_{0gt\Phi i} s_{gt} \Delta T_t - M$
$\sum_{t}\sum_{g}\sum_{\Phi i(g)} \pi_{\Phi i(g)} f_{CO2\Phi i(g)} B_{0gt\Phi t} s_{gt} \Delta T_t - \overline{\mathrm{PCO2}}_{Italy}$

Matrice A	I(L1,t1)	I(L2,t1)	I(LN,t1)
0	1	0	0
0	-1	0	0
0	0	1	0
0	0	-1	0
0	0	0	1
0	0	0	-1

EGT *	WGT *	Emiss	GCBuyET	GCBuyCDM	MargCO2
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0

X(L1)	X(L2)	X(LN)
-1	0	0
-1	0	0
0	-1	0
0	-1	0
0	0	-1
0	0	-1

b
I1max
-I1min
I2max
-I2min
INmax
-INmin

Tutta la matrice A
fino a questa
colonna contiene

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