A cost-benefit analysis of transmission network reinforcement driven by generation capacity expansion

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***Abstract*—This paper assesses the effects of the future European power generation system with strict CO_2 emission reduction targets on the planning of cross-border interconnection lines. Results from a techno-economic energy systems model have been used as input to this work, regarding the development of the European power generation system until the year 2050, meeting the EU 2020 CO_2 target and a 85% emissions reduction until the year 2050. A simplified UCTE power system model was developed in order to analyze how the cross-border interconnections in continental Europe are affected by the generation plans using an iterative method. The paper also attempts to identify the congestion points and proposes solutions based on nodal price modeling. A cost-benefit analysis (CBA) is used to evaluate the appropriate transmission planning strategy, with the costs being the long-term investment costs and the benefits being both the avoided environmental costs and the total congestion costs. The effects of new investments on the nodal prices are also studied. The results show that the profitability of the investments is influenced by the available production mix and the forecasted CO_2 prices. The avoided congestion costs participate rather insignificantly in the CBA, which means that congestions are not relieved, showing that many interconnections are insufficient for nodal pricing market structure.**

***Index Terms*—Future electric power systems, generation capacity expansion, transmission planning, CO_2 emission cost-benefit analysis.**

I. INTRODUCTION

Often the generation capacity expansion studies do not take into account the capacity of the transmission network, which frequently becomes weaker and more vulnerable under competitive market conditions. The coordination of generation and transmission planning has turned into a very complicated exercise to solve based on strategic behavior, many uncertainties and political decisions. This paper deals with the interaction between new installed production capacity and transmission investments, as a result of a cooperative work between the ”Pathways to Sustainable European Energy Systems” project (hereafter called the ”Pathways project”) at Chalmers University of Technology and the ”Towards future electricity networks” project initiated by the power systems laboratory at ETH Zurich.

The goal is to identify common investment strategies for supporting the power plants of the future with appropriate electricity network plans building a sustainable power system. The Pathways project aims at investigating possible pathways for the stationary energy sector which can meet strict requirements of CO_2 emission targets in line with what has been proposed by the EU. Typically, the stationary energy system (electricity and heat) contribute to at least a third of the total European CO_2 emissions. Looking at the energy mix of the future, many options are available. A large share of the European electricity is generated in large centralized power plants and cost efficient options for reducing CO2 emissions from these plants are fuel shift (coal to gas), application of CO2 capture and storage and co-firing of biomass. This is of course assuming there is a cost to emit CO2 such as from the EU Emission Trading Scheme (EU-ETS). In addition, new renewable technologies such as biomass combined heat and power and wind power are important CO2 mitigation technologies as is demand side efficiency measures. Another option is introduction of poly-generation plants for co-production of power, heat and transportation fuels. It also seems possible to electrify the transportation sector by use of plug-in hybrid electric vehicles (PHEVs), which may be a cost efficient way to reduce CO_2 emissions from the transportation sector. Thus, the two latter options represent technologies which increase the interaction between the transportation sector and the stationary sector (heat and power).

Increased integration of the electric power system and the transportation sector as well as an increased use of fluctuating power generation (most notably wind power) imposes new challenges on the electricity network. As indicated above, a central part of the Pathways-project is to analyze development paths for the power generation sector under various constraints and targets concerning renewable energy based power generation and CO_2 emissions reductions. The analysis is typically carried out by so called techno-economic modeling which gives the mix of technologies until the year 2050, minimizing the overall system cost fulfilling the targets specified.

The example in Figure 1 depicts the German production mix as modeled by Odenberger et al. [1]. Results from such models give valuable information on the overall possibilities for developing the power generation system. However, the

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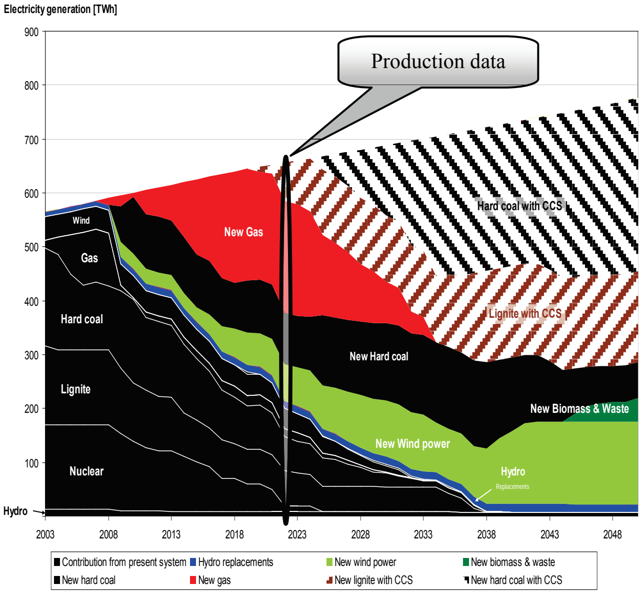

Fig. 1. An example of output from the energy system model - example is the German electricity generation: 75% Reduction in CO2 by 2050, relative to 1990.

techno-economic modeling applied does not include any detailed analysis on the requirements imposed by the physical constraints of the electricity network. Thus, this work attempts to consider the interactions of the network constraints on the generation expansion plans and identify the needs for new investments in transmission systems.

The paper is organized as follows: Section II presents a brief overview of the transmission system planning methods and its importance in the evolution of the generation system. Section III discusses the proposed method used in this paper. Section IV introduces the simplified EU 20-node system and the snapshots in different years in the planning horizon. Section V presents the results. Finally, conclusions are drawn in Section VI.

II. EFFECTS OF GENERATION SYSTEM ON TRANSMISSION NETWORK PLANNING

Transmission system expansion planning has been performed with various techniques and algorithms as summarized in [2]. In general, the objectives of transmission planning is to provide cost-effective, safe and reliable transmission system in a socially and environmentally responsible manner, so that the system loads are satisfied. The transmission planning should also be able to manage various uncertainties in power systems such as uncertainties in future power generation, fuel costs, load variations, as well as time for design, approval and construction of new high voltage transmission lines [3]. Typically new transmission lines may take 7-10 years to go through the process of planning, permitting and construction, however one should also consider policy and terminology differences among the European countries that makes the completion of network expansion projects hard to forecast [4]. Lead times considerably longer than these mentioned above can sometimes be encountered.

Recently, the conditions for transmission network planning have changed due to deregulation of the energy markets.

Under regulated conditions the responsible authority for network expansion has a better overview of the planned generation capacity, the locations of new power plants and based on demand forecasting the planning process can be optimized aiming mainly to the minimization of overall costs, i.e. reliability costs or operating costs [5].

In deregulated systems generation expansion and transmission planning are separated, driven by market based initiatives. The latter implies many risks due to diversified interest of stakeholders, exercise of market power and lack of transparency. The investments in transmission and generation depend on market signals, that sometimes are inaccurate neglecting many externalities, e.g. production external costs and loop flows of transmitted power. Therefore, misleading price signals may force developments towards to suboptimal system expansion in favor of some generators over others [6].

Accordingly, transmission expansion planning based only either on congestion relief or on minimization of consumer costs should be avoided in a power market. The minimization of total congestion costs and total production costs should be the objective in order to obtain the optimal solution, as claimed by Stoft in [7]. Additionally, the problems of climate change have been fully recognized in the EU directives with the CO_2 emission reduction targets in EU member countries. This, calls for new ways of planning both future generation and transmission systems taking into account also the emissions reduction targets.

In this paper, results from generation planning model considering environmental constraints, are used in the evaluation of transmission planning scenarios. On the one hand, the generation capacity planning has already taken into account the CO_2 emission constraints, the transmission model on the other hand generates the dispatch of power, taking into account changes in generation technologies, marginal costs and lines capacities using a multi-period optimal power flow model as explained in the following.

III. PROPOSED METHODOLOGY

A. Iterative process

In this paper, an integrated iterative process for generation and transmission system planning is proposed. The applied methodology is presented in the flowchart of Figure 2.

It has been assumed that the generation capacity expansion takes place first and a centralized entity is responsible for the optimization of the transmission planning based on proposed strategies of all system stakeholders. With the generation scenarios, which were produced by the GEP, a DC-OPF run in order to identify possible bottlenecks in the network. Since the model used is a simplified 20-bus system model which approximately represents 20 EU countries, we will focus on the interconnections between the nodes rather than on the bottlenecks within each country.

B. Optimal power flow model

A modified version of the sustainability based optimal power flow (SOPF) [8] has been used. The model is an

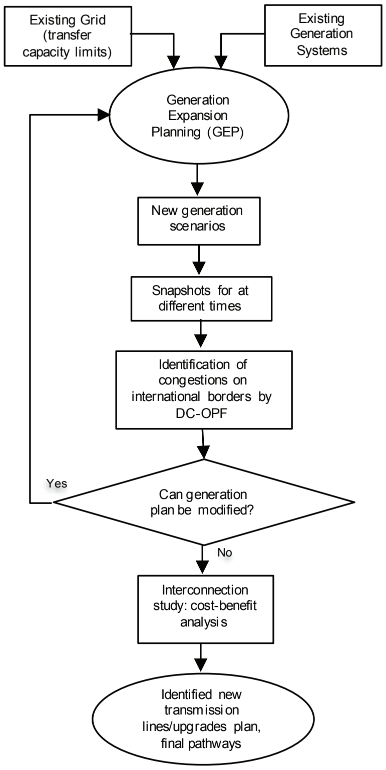

Fig. 2. The applied iterative process

equilibrium model, simulating the concept of implicit auctions for a single market in Europe. The market participants, e.g. consumers and producers, bid and offer until a single system price has been reached, taking into account power exchanges and the physical limits of the transmission network. Merit-order curves are considered for producers and the demand is considered inelastic, however, it would be rather straightforward to model a price responsive load. Thus, the problem of maximization of social welfare (SW) becomes a problem of minimization of system operating cost.

$$max\{SW\} \Rightarrow min\{\sum_{i=1}^{n} MPC_i\} \Rightarrow \tag{1}$$

$$min\{\sum_{i=1}^{n}(\Pi_i) * P_i\} \tag{2}$$

s.t.

equalities	inequalities
$P_i - L_i - \sum Pf_{ij} = 0$ $L_i = inelastic$	$P_i, L_i > 0$ $P_{i_{min}} < P_i < P_{i_{max}}$ $-TCL_{ij_{min}} \leq Pf_{ij} \leq TCL_{ij_{max}}$

where

i	number of nodes
MPC_i	marginal production cost for a node i (€/MWh)
Π_i	marginal price (€/MWh) for a specific level of injected power
L_i	demanded power at node i (MW)
P_i	injected power at node i (MW)
TCL_{ij}	the transmission capacity limit from node i to node j (MW)
Pf_{ij}	power exchanges from node i to node j

As it will be presented, congestions on the transmission lines prevent the system from providing a common price to all the participants and consequently different nodal prices are assigned to each one of the nodes. Based on this price differentiation, the transmission network utilization is given a price, which means additional costs for power exchanges, the so called congestion costs.

C. Cost-benefit analysis (CBA)

In traditional least cost planning method, the optimal project is selected based on its minimum cost. However, this is only an economic criterion, and the project still might not be able to provide satisfactory profit. In this paper, a cost benefit analysis method is applied instead. The method will help to select the project with the discounted benefit greater than its discounted cost. This is an indication of profitability of the project.

The benefits from a proposed transmission project consist of a societal and a market based element as in equation 3. The first element is assigned to environmental benefits, if any, and the other to the reduction of congestion surplus in the network.

$$benefits_k = (AEC_k + ACC_k) \tag{3}$$

a) Avoided environmental costs (AEC): when new capacity in generation and transmission is available, the dispatch of the power plants changes as well, which means that the output power of some conventional power plants will change consequently. In order to calculate the environmental benefits derived from a proposed project, the difference of the generation output with and without the new transmission capacity has been used as shown in equation 4:

$$AEC_k = \sum_{i=1}^{nodes} \Delta Q_i * EC_i \tag{4}$$

where

EC_i	is the external cost per MWh associated with each type of production fuel. In this paper only CO_2 costs are taken into account, but other costs can also be included.

b) Avoided congestion costs (ACC): This cost represents the congestion costs that could be avoided by the use of the new transmission line. The congestion costs are calculated as the product of the nodal price difference between two nodes and the amount of power transfer between these two nodes. This method is widely used for congestion management in pool markets, e.g. PJM [9]. The avoided congestion cost is calculated for each candidate lines for all the years considered, equation 5.

$$ACC_k = \sum_{i,j=1}^{nodes} (\Pi_i - \Pi_j) * Pf_{ij} \tag{5}$$

The benefits are discounted to the present year using an appropriate discount rate. Economically, an investment is made when the overall benefits of the investment are greater than all the costs, i.e. initial investment and operation and maintenance costs. In this study, a discount rate of 8% has been applied and only aggregated investment costs are taken into account.

The costs of new investment for a double circuit 380kV overhead line based on a European study [10], differ from country to country as presented in the Table I (base case cost has been considered 401 k€/km):

TABLE I
TRANSMISSION INVESTMENT COSTS 380KV OVERHEAD LINE

	kEuro/km	Specific cost factors
Finland, Sweden	200 - 300	Flat land(fewer towers), less populated
Greece, Portugal	200 - 300	Low costs (land, labour)
Denmark, Norway, Spain	300 - 400	Close to base case
Belgium, Netherlands, Italy	400 - 500	Close to base case, heavily populated
France, Germany	500 - 600	Heavily populated, high labour costs
UK(England & Wales)	600 - 800	n-2 standard applied, more towers/km, high right-of-way costs, heavily populated
Austria, Switzerland	600 - 800	High environmental issues, topography, high wind pressure limits, high labour costs

The CBA process is described in the flowchart shown in Figure 3. The ”business as usual” (BAU) case considers changes in available generation mix, however without any transmission network reinforcements. First of all the congested lines are identified for the whole period k in BAU, divided in permanent and non-permanent. The permanent congestions are the final candidates for expansion. Due to the size of the system the proposed scenarios consist of more than one candidate line.For each one of the scenarios the results are compared with the (BAU) case in order to calculate the benefits in every year. The process ends when all the scenarios have been assessed and ranked.

For the assessment of the investment plans a benefit-to-cost-index (BCI) is used, described in equation 7. The average BCI for the whole planning horizon provides a ranking representation of the results.

$$avgBCI = (\sum_{k=1}^{years} BCI)/years \tag{6}$$

$$BCI = \frac{benefits_k}{(1+r)^k * IC_k}, BCI > 1 \rightarrow profitable \tag{7}$$

where ,

IC_k is the hourly cost in year k of the transmission line investment (IC) calculated using appropriate capital recovery factor (CRF) taking into account the fixed discount rate and the number of years in the transmission project [10]. It is assumed that the transmission line is used whole year round.

$$IC_k = (IC * CRF)/8760 \tag{8}$$

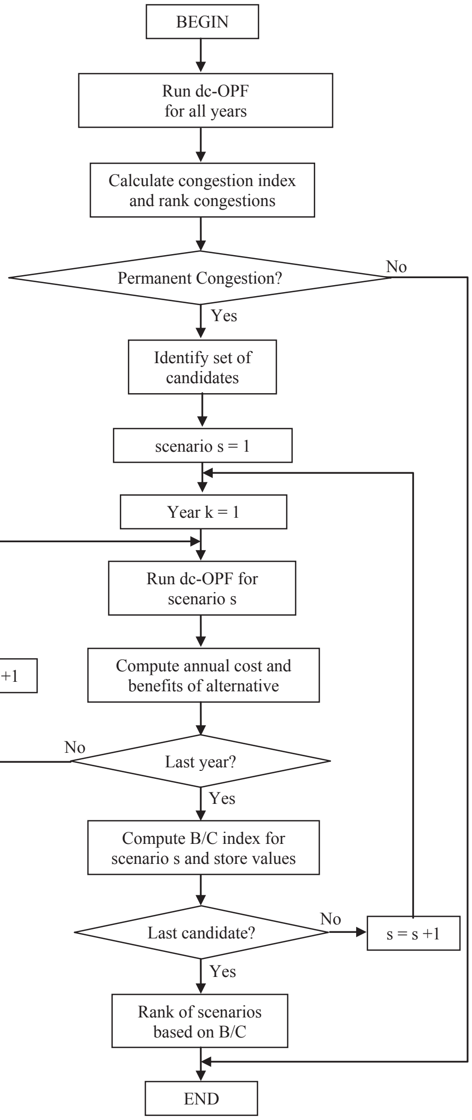

Fig. 3. The applied methodology for BCI calculation

CRF the capital recovery factor distributes a present value to annuities, for a fixed discount rate r and period [11].

$$CRF(r, years) = \frac{r(1+r)^{years}}{(1+r)^{years}-1}, years \geq 1 \tag{9}$$

A sensitivity analysis is also carried out, evaluating the projects using different levels of CO_2 prices, in order to provide better information on the project ranking. As the policy issues have an impact on electricity prices and generation dispatch, it may happen that a new transmission line is no more profitable when the environmental costs are assumed lower. Forecasts of CO_2 high - low costs have been generated from ELIN model [12].

IV. SIMPLIFIED UCTE MODEL

A. 20-node System

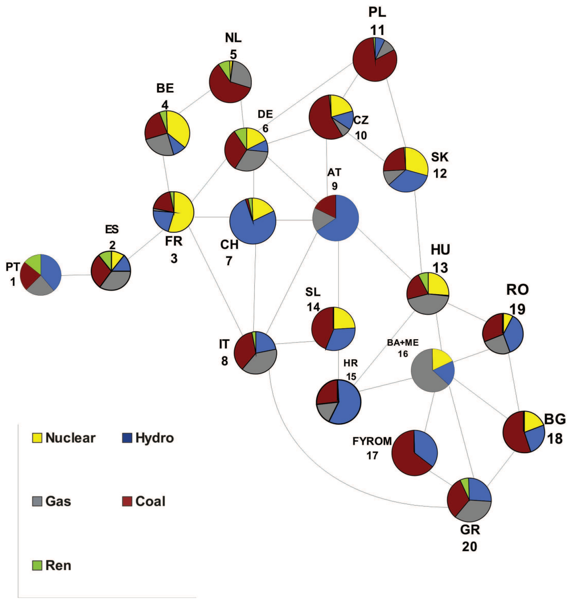

Fig. 4. Simplified 20-nodes European system

The model used in this paper is a static representation of December 2007 of the European interconnected system consisting of 20 nodes, as in Figure 4. Production and consumption is assigned to each node, while six types of production technologies are considered, nuclear, coal, gas, hydro, renewables and carbon capture and storage for thermal power plants. Generation and demand are based on public available data from EnTSO-E [13]. The option of carbon capture and storage (CCS) technology is added in the planning process after some years using the input of the ”Pathways” project. A value for the marginal cost of CCS integration has been assumed according to the IEA report [14]. The CO_2 cost, different each year, is assigned to the fossil fuelled technologies, according to the CO_2 prices (€/tonne) obtained from the ELIN, i.e. corresponding to the Pathway shown in figure 1.

The economic model of the 20-bus system is composed of some other assumptions as well, as economic data for power plants, e.g. marginal production costs, are not available. It has been assumed that renewable technologies produce at the lowest price level and then follows nuclear power plants, fossil fuels and hydro, although electricity price differences among countries have been taken into account and thus, this order may differ in some cases. For instance, hydro power in Switzerland is cheaper than in Italy and hard coal cheaper in Germany than in France, except for nuclear power that has the same price Europe-wide. Among fossil fuels only gas is considered separately associated with higher price than the single price of coal, hard coal and lignite. Price disparities and the aggregated merit-order curve of the system are presented in Figure 5.

Regarding transmission lines, the transfer capacities are collected from EnTSO-E [13], equal to the net transmission capacities, assumed as equal for both directions. Physical data on the interconnections, e.g. line reactances, are obtained from typical values according to Table II [15], based on estimated line lengths.

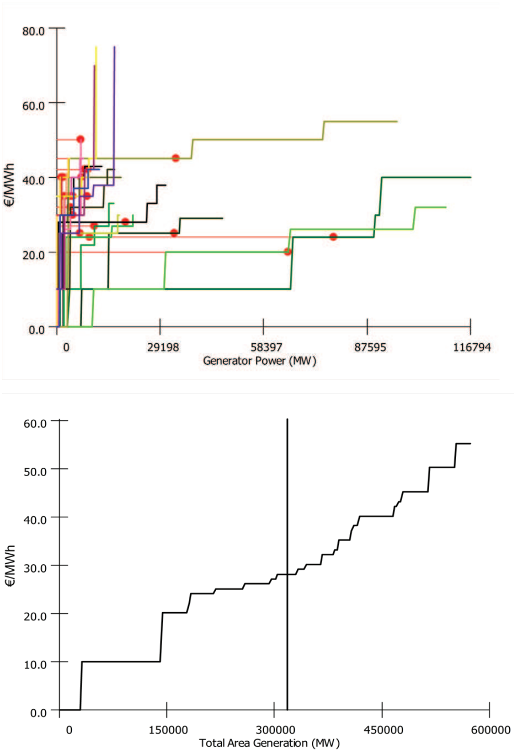

Fig. 5. Merit-order supply curves

TABLE II
TYPICAL VALUES FOR OVERHEAD TRANSMISSION LINES

Nominal Voltage	230kV	345kV	500kV	765kV	1100kV
R (Ω/km)	0.05	0.037	0.028	0.012	0.005
$x_L=\omega L$ (Ω/km)	0.488	0.367	0.325	0.329	0.292
bc=ωC (mS/km)	3.371	4.518	5.2	4.978	5.544
Zc (Ω)	380	285	250	257	230
SIL(MW)	140	420	1000	2280	5260

V. RESULTS

The generation case that has been applied is described in [12]. According to this case the future available generation mix until 2050 is calculated based on marginal cost effective solutions. In the simulations starting point is the year 2008 and only the first 25 years have been used. The results are obtained by comparing the different scenario cases with the BAU scenario.

- In the so called BAU scenario increasing demand by 1.06% in average and CO_2 emissions reduction by 30% by 2020 are considered. Therefore, renewable technologies are promoted and also carbon capture and storage (CCS) is introduced for coal fired power plants mainly after the year 2020, i.e after 12 simulated periods.

In Figure 8, the initial situation of the BAU case is presented. During the total period of 25 years only some minor changes in congestions appear, and so the scenarios are based on this picture. Due to congested lines there is not a common price for the whole system, however 3 prices zones are obviously identified, e.g. red for expensive, blue for cheap and green for middle price zone. The most expensive node appears to be node 8, that corresponds to Italy. For that reason a large amount of power is transferred to the south from the neighboring nodes, influencing the direct interconnections to Italy as well as other interconnections, through the produced loop-flows.

The trilateral market coupling of Belgium, Netherlands and France is also very clearly recognized, as these 3 nodes belong to the same price zone and no congestions appear between them. The most critical lines of the network seem to be the cross-border connections of node 6 that corresponds to Germany. Germany, together with France (node 3), is the major exporter of the system, providing a large amount of power mainly to the east. Another important and active exporter of the system turns out to be node 14 (Slovenia), although its production capability is rather limited. The strategic position of Slovenia makes it a significant arbitrator, facilitating the flows form the north to Italy and to the south Eastern Europe.

According to the aforementioned observations the following transmission expansion scenarios have been proposed and assessed:

TABLE III
PROPOSED TRANSMISSION INVESTMENT SCENARIOS

	From	To	actual tran. capacity (MW)	additional tran. capacity (MW)	Inv. costs (M€)
scenario 1	7 (CH)	9 (AT)	1200	1800	500
	7 (CH)	8 (IT)	3890	1110	
	6 (DE)	9 (AT)	2000	2000	
	1 (PT)	2 (ES)	1300	700	
scenario 2	6 (DE)	9 (AT)	2000	1000	365
	14 (SL)	15 (HR)	900	1100	
	6 (DE)	10 (CZ)	2300	1700	
scenario 3	9 (AT)	14 (SL)	650	650	400
	6 (DE)	5 (NL)	3000	1000	
	6 (DE)	10 (CZ)	2300	1700	
	1 (PT)	2 (ES)	1300	700	
scenario 4	6 (DE)	10 (CZ)	2300	1700	620
	6 (DE)	11 (PL)	1200	1800	
	1 (PT)	2 (ES)	1300	700	
scenario 5	9 (AT)	14 (SL)	650	850	300
	11 (PL)	12 (SK)	550	950	
	6 (DE)	9 (AT)	2000	2000	

In Figure 6, the calculated cash flows of the five scenarios are presented. From the form of the curve derives that the avoided environmental benefits contribute more than the avoided congestion costs to the cost-benefit analysis. During the first 5-6 years, while still old, inefficient technologies are in charge, but also the integration of renewable technologies increases, the avoided environmental costs thanks to the additional transmission capacity are higher than at the end of the period when new production technologies have been installed and own a higher fraction in the energy mix. It means that through the additional transmission capacity more ”green” power flows. In the middle of the period a peak appears due to the dispatch of new CCS power plants. As the demand increases and the dispatched generators do not change significantly, the benefits become negative.

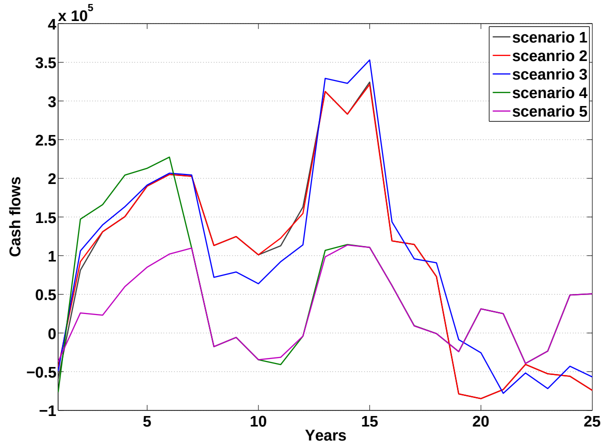

Fig. 6. Cash flows of the scenarios

However, from Figure 7, all the scenarios are profitable during the whole period. The average BCI is greater than 1 for all of them, which means that the benefits are higher than the costs. Referring to this index the second scenario seems to be the most profitable for the pessimistic case of high CO_2 price development, e.g. from 17 up to 32 €per tonne in the year 2035, although this scenario considers only three transmission lines and it’s not the cheapest one. For the optimistic case of lower carbon dioxide prices development, e.g. from 17 up to 27.5 €per tonne, the index provides approximately the same results, despite the lower BCI values. A major difference is that the fourth scenario is in a critical position as the benefits turned out to be almost equal to the costs, and that the fifth scenario is not profitable any more, although in the previous case it was more advantageous than the fourth one.

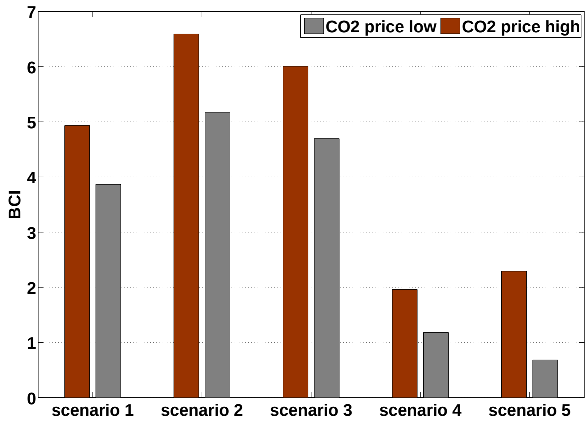

Fig. 7. BCI ranking for low and high CO_2 prices

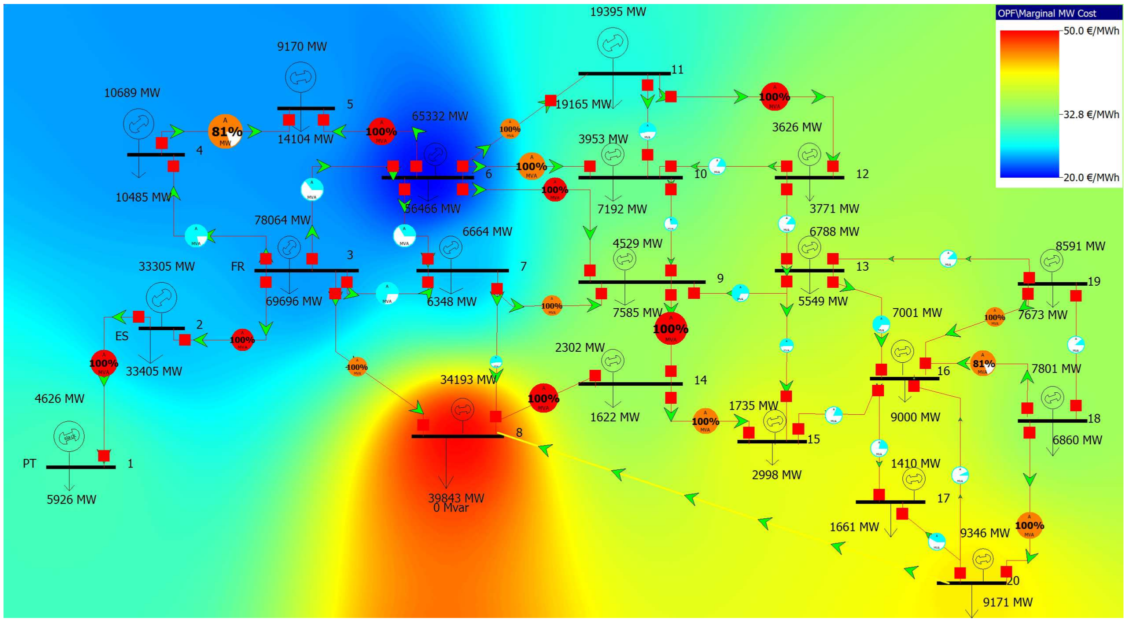

Fig. 8. Price zones and congested lines

VI. CONCLUSION

In this paper two models have been combined in order to study the effectiveness of new transmission plans, regarding environmental and market aspects. One was the generation expansion model (ELIN), that calculates the optimal future generation mix satisfying 30% CO_2 emissions reduction by 2020 and the other the modified sustainability based optimal power flow model that considers transmission network constraints, providing price signals under nodal pricing market structure.

The proposed iterative cost-benefit analysis method has been applied on a 20-bus simplified European ”cooper-plate” system model. The results have shown that the profitability of the investments is influenced by the available production mix and the forecasted CO_2 prices, as obtained from ELIN. The avoided congestion costs participate rather insignificantly in the CBA, which means that despite the additional transmission capacity, congestions are not relieved. Therefore, many interconnections are insufficient for nodal pricing market structure, as exchanges between the participants are highly promoted and stronger reinforcement of the transmission lines is needed if the target is the reduction of congestion costs. Regarding environmental issues the proposed investments are beneficial under both cases of CO2 price development for the period of 25 years, supporting generation strategies for greenhouse gas emissions mitigation, except for scenario 5 that is unprofitable for the case of low CO_2 price development.

Nevertheless, due to limited data availability, the internal bottlenecks within countries are neglected. More detailed models are needed for the representation of inland congestions, subject to future work.

APPENDIX A
NODES - COUNTRIES

TABLE IV

Node	abbr.	Country
1	PT	Portugal
2	ES	Spain
3	FR	France
4	BE	Belgium
5	NL	Netherlands
6	DE	Germany
7	CH	Switzerland
8	IT	Italy
9	AT	Austria
10	CZ	Czech Republic
11	PL	Poland
12	SK	Slovakia
13	HU	Hungary
14	SL	Slovenia
15	HR	Croatia
16	BA+ME	Bosnia / Serbia
17	MK	F.Y.R.O.M.
18	BG	Bulgaria
19	RO	Romania
20	GR	Greece

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