LONG TERM MARGINAL PRICES – SOLVING THE REVENUE RECONCILIATION PROBLEM OF TRANSMISSION PROVIDERS

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Abstract – This paper describes a model to perform transmission expansion planning studies together with the computation of Long Term Marginal Prices along the planning horizon. The model includes four criteria and adopts a Simulated Annealing based algorithm to solve the problem. The algorithm also provides Long Term Marginal Prices reflecting both investment and operation costs, thus being able to conveniently address the Revenue Reconciliation Problem that would arise if short-term approaches were used. The paper includes a case study based on the 400/220/150 kV Portuguese transmission system to illustrate the application of the proposed algorithm and highlight its potential.

Keywords – Transmission Expansion Planning, Long Term Marginal Prices, Marginal Remuneration, Revenue Reconciliation, Simulated Annealing.

1. INTRODUCTION

The liberalization and restructuring of the electricity sector lead to the unbundling of traditional vertical utilities in a number of new agents devoted to specific activities as generation and retailing, network both in transmission and distribution, coordination regarding market management and system operation and regulation. This new structure lead to new relations between agents, to a progressive decoupling between the flow of electricity and the flow of money, and it requires an unbundling of traditional tariff schemes, namely with the creation of specific tariffs to remunerate network providers for their costs. These tariffs should be established using robust methods, while leading to transparent and fair systems and transmitting economic signals to the grid users to improve efficiency.

In particular, tariffs for the use of transmission networks must be set so that they remunerate costs incurred along two time scales. A short-term one in which one takes into account operation costs (as loss and congestion costs) and a longer term one to consider investment and expansion costs. If these two time scales are not properly considered, investments will certainly be reduced with the well-known consequences in terms of the degradation of quality of service and an increase of the risk of blackouts.

In recent years these issues got particularly serious in view of the problems experienced by power systems in a wide number of geographical areas. Apart from the need to maintain security and reliability standards, transmission networks are the places were electricity markets are physically established and therefore should not impose bottlenecks to dispatch strategies arising from centralized markets or from bilateral contracts. In Europe, the Directive 2003/54/EC Concerning the Common Rules for the Internal Market in Electricity states in article 9 that "each transmission system operator shall be responsible for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity". This text turns transmission expansion planning into a more challenging and difficult exercise than in the past since it emerges a new type of uncertainty regarding the location and the size of new generation. If one has in mind the difficulties usual in several countries in licensing new lines, one clearly has a picture of an increasingly complex problem. In this context, more than in the past, flexible approaches able to deal with risk are clearly needed.

Transmission costs, both in the short-term and in the long-term, have to be evaluated and properly allocated to network users. The literature describes a large number of cost allocation methods typically classified in average cost methods (as the postage stamp, contract path method, for instance) [1, 2], incremental approaches, and marginal approaches [3, 4, 5]. Marginal methods are the most robust ones both from a technical and an economic point of view, namely given the economic signals they can transmit to network users to induce more efficient uses of the networks. They can only reflect short-term operation costs, leading to Short-Term Marginal Prices, STMP, or they can include investment costs leading to the computation of Long-Term Marginal Prices, LTMP. STMP are more easily computed but they usually lead to a Revenue Reconciliation Problem since they are typically able to recover a small percentage of transmission-regulated costs. LTMP inherently address this problem but they are more difficult to compute since they require solving a long-term transmission expansion problem.

This paper describes a multicriteria long-term transmission expansion planning problem and an approach to compute LTMP. The formulation considers four criteria: operation costs, investment costs, a reliability index corresponding to the Expected Energy Not Supplied and a risk index represented by the Exposure Index as a way to deal with uncertainties in demand along the planning horizon. This multicriteria problem is solved by formulating an auxiliary single objective problem considering that all criteria but one are converted into constrains using aspiration levels specified by the Decision-Maker. This allows one to identify a non-dominated solution of the complete problem to be presented to the Decision-Maker. If not satisfied with the current solution, the Decision-Maker can modify the aspiration levels and solve the problem again.

The auxiliary single objective problem still retains a large degree of complexity given its discrete multiperiod nature. To take this into account, the developed formulation uses a list of possible investments from which it will be built an expansion plan by selecting investments and their locating in a particular period. In order to retain this discreteness and to deal with the combinatorial nature of the problem we used Simulated Annealing.

The paper is organized as follows. In Sections 2 and 3 we review traditional transmission expansion concepts and models, regulatory issues and cost allocation methods. Sections 4 and 5 describe in detail the mathematical formulation of the problem and the developed solution algorithm. Section 6 presents a Case Study based on the Portuguese 400 /220 /150 kV transmission network for which we executed a 6-year planning exercise and performed a cost recovery analysis in order to check if the referred Revenue Reconciliation Problem was adequately addressed when using Long Term Marginal Prices. Finally, Section 7 draws the most relevant conclusions.

2. TRANSMISSION EXPANSION PLANNING

Transmission expansion planning problems are very complex ones due to a number of aspects:

- they have a multiperiod dynamic nature in the sense that it is crucial to adopt an holistic view over the entire horizon although this horizon can be discretized in a number of periods, for instance annual ones. This means that an expansion planning exercise over np periods does not correspond to run np independent exercises in a sequential way. On the contrary, the whole horizon should be treated at one time in the sense that an expansion is commissioned for a period taking not only in consideration the requirements of that period but also its impact in the future;
- they exhibit a geographic coupling in the sense that the planner shouldn't restrict himself to build new installations as answers to local problems. In meshed networks as transmission ones, solving a problem can also address bottlenecks in other locations, so that there is a global nature that shouldn't be lost;
- they are discrete problems due to the nature of investment decisions;
- they are affected by load uncertainty over the horizon. A plan should be adequate not only for a given load evolution but the decision maker shouldn't feel any significative regret if the future will not be exactly as expected. This immediately leads to risk analysis under which flexible solutions are most welcome.

The available literature on this area can be grouped in two large sets of publications and approaches:

- in the first set we include approaches and commercial tools to analyze pre-prepared expansion plans that evaluate reliability and security indices, for instance;
- in the second set, we consider models and algorithms typically developed in an academic environment that, according to several simplifying assumptions, aim at building expansion plans. They can be linear or non-linear models, they can use dynamic programming, non-linear optimization approaches, branch & bound techniques or metaheuristics [6-11], but for some reason they fail in addressing in a complete way the issues referred in the previous paragraphs.

3. REGULATORY ISSUES AND COST ALLOCATION METHODS

As part of the unbundling process, transmission networks are operated by independent entities, the ISO. In several countries, these entities are also the owners or at least they have the concession of transmission networks leading to Transmission System Operators, TSO.

Transmission providers have a number of costs for which they must be remunerated through tariffs for the use of networks. These costs include operation, investment and depreciation costs as well as administrative and other fixed costs. Despite the crucial role transmission companies have in providing the physical infrastructure to establish power flows resulting from market relations, the share of their costs in the end user tariffs is typically small, around 5%. These companies are usually very efficient and they typically achieved high automation levels. For that reason, Regulatory Agencies adopted in several countries Cost of Service / Rate of Return, CoS/RoR, approaches to regulate them. Under this approach, a regulated company submits an estimate of its costs for next year as well as its assets. The regulated costs result from adding the approved estimated cost plus a term resulting from the application of a remuneration rate over the assets. This amount will then be converted into tariffs for the use of the network.

The above reasoning implies that expansion investments must be carefully evaluated by Regulatory Agencies since they have a direct impact on tariffs. While the new installations are built, investment costs are considered as regulated ones and, once commissioned, they are converted into assets and remunerated using the referred rate. In view of this, Regulatory Agencies should approve the least costly expansion plan that, in any case, adequately meets security and reliability criteria.

The regulated remuneration of a transmission company can be converted into tariffs for the use of the network using a variety of methods usually grouped in three sets:

- embedded approaches based on average cost methods – these approaches can be very simple as the Postage Stamp or they can eventually require solving power flow studies as the MW.mile, the Modulus or the Zero Counterflow approaches. In general, they suffer from a lack of technical robustness and they fail in transmitting economic signals to network users;
- incremental methods – they compare a base operation point of the system with another one that considers a new transaction. The variation of the costs leads to Incremental Prices. They may be easily applied if the number of transactions is reduced, but they are unpractical in modern power systems;
- marginal methods – in this case one aims at evaluating the impact on the cost function of the system from varying the load in a given node (1). The resulting prices typically display a geographic differentiation due to congested lines, losses and to the existence of predominantly generation areas and predominantly demand areas. According to (1) this means we are computing nodal marginal prices.

$$\rho_k(t) = \frac{\partial f(t)}{\partial Pl(t)_k} \qquad (1)$$

Among these three classes, marginal methods are the most robust ones from a technical point of view and are able to transmit economic signals to grid users. Marginal approaches can lead to the calculation of Short Term

Marginal Prices, STMP, or Long Term Marginal Prices, LTMP. The first ones only reflect short-term operation costs, as losses and congestion costs. STMP are easily computed as subproducts of a short-term dispatch problem but are generally very volatile. LTMP are computed in the scope of an expansion-planning problem in which assets are allowed to vary along the planning horizon. They are more stable since they include a long-term trend reflecting the remuneration of investments. However, their computation is far more complex since it is performed within a transmission expansion-planning problem.

As a consequence, a major difference between Short and Long Term Marginal Prices is related with the Revenue Reconciliation Problem. Typically, the Marginal Remuneration corresponds to a small percentage (usually 10 to 20%) of the regulated costs if we use Short Term Prices [12, 13]. However, if we use Long Term Marginal Prices, the Revenue Reconciliation Problem is inherently addressed since investment costs are also considered.

4. TRANSMISSION EXPANSION PLANNING MODEL

4.1 Short Term Operation Costs

The transmission expansion model integrates four criteria that will be defined in the next paragraphs. The first one corresponds to operation costs, OC, along the planning horizon. OC costs are evaluated using the linearized DC dispatch model (2-6) that is run for each period in the horizon. In each of them, one considers the installations commissioned in that and in previous periods and the load forecast specified by the planner. In this model:

- c_k, Pg_k and Pl_k - variable generation cost, generation and load connected to node k;
- G - penalty assigned to Power Not Supplied, PNS;
- a_{bk} - sensitivity coefficient of the active power flow in branch b regarding the injected power in node k;
- Pg_k^{min}, Pg_k^{max} - minimum and maximum output of the generator connected to node k;
- P_b^{min}, P_b^{max} - minimum and maximum active power flow in branch b.

$$\min f = \sum c_k.Pg_k + G.\sum PNS_k \quad (2)$$

$$\text{subj} \quad \sum Pg_k + \sum PNS_k = \sum Pl_k \quad (3)$$

$$Pg_k^{min} \le Pg_k \le Pg_k^{max} \quad (4)$$

$$PNS_k \le Pl_k \quad (5)$$

$$P_b^{min} \le \sum a_{bk}.(Pg_k + PNS_k - Pl_k) \le P_b^{max} \quad (6)$$

In order to turn the dispatch more realistic, we can include an estimate of branch losses in it. The next algorithm details the approach used to obtain this estimate.

Algorithm

i) Run an initial dispatch using (2) to (6);
ii) Compute voltage phases using the DC model;
iii) Estimate active losses in branch m-n using (7). In this expression, g_{mn} is the conductance of branch m-n and θ_{mn} is the phase difference across it;

$$Loss_{mn} \approx 2.g_{mn}.(1-\cos\theta_{mn}) \quad (7)$$

iv) Add half of the losses in branch m-n to the original loads in nodes m and n and run a new dispatch using (2) to (6);
v) Compute voltage phases using the DC model;
vi) End if the difference of voltage phases in all nodes is smaller than a specified threshold. If not, return to iii).

When this algorithm converges, it provides the dispatch required to supply loads as well as an estimate of losses. This means that the objective function of this DC based dispatch reflects generation costs, losses as well as the surplus costs due to congested lines. Once these yearly operation costs are obtained, one can compute total operation costs, TOC, by referring the yearly values to the initial period using a return rate r (8).

$$TOC = \sum_{p=0}^{np-1} \frac{OC_p}{(1+r)^p} \quad (8)$$

4.2 Long Term Investment Costs

Long-term costs directly result from the investments commissioned in each period of the horizon. This means one can evaluate the yearly investment costs as the addition of investment and expansion costs of the installations built in each period. In order to obtain total investment costs, TIC, it is also used a return rate r as indicated in (9).

$$TIC = \sum_{p=0}^{np-1} \frac{IC_p}{(1+r)^p} \quad (9)$$

4.3 Expected Energy Not Supplied, EENS

The Energy Not Supplied is an important reliability index characterizing the ability a power system has to supply loads along a time frame in view of the non-ideal nature of system components. In meshed generation-transmission systems the computation of an estimate of ENS typically requires running a time-consuming chronological Monte Carlo simulation. In our case, the Expected Energy Not Supplied was evaluated for each period in the horizon using the pseudo-chronological Monte Carlo Simulation detailed in [14]. This approach retains the advantages of chronological simulations in terms of assessing the duration of states and the energy not supplied while being computationally very efficient, in fact quite close to sequential non-chronological approaches.

4.4 Exposure Index, Iexp

The Exposure Index is a risk index that aims at evaluating the flexibility of a system in accommodating load uncertainties modeled, for instance, by fuzzy sets. Fuzzy sets are mathematic entities created by L. A. Zadeh back in 1965 and can be defined by sets of ordered pairs, in which the first element in the pair is an element of the universe of discourse and the second is its membership value, also known as the degree of compatibility of that element of the universe with the definition of the fuzzy set. Fuzzy sets have been extensively used in several applications namely to incorporate information about the subjectiveness of human beings or about phenomena regarding which there is not complete information.

Using the model described in [15], loads will be defined by trapezoidal fuzzy numbers. Then for each period in the horizon, it is run a Fuzzy Optimal Power Flow exercise to compute the membership function of Power Not Supplied reflecting the specified uncertainties.

Let us admit that for a period p one obtains the PNS membership function depicted in Figure 1. This figure indicates that the system is robust, that is there is no power not supplied, if load uncertainties occur above level α. However, if load increases for uncertainty levels lower than α, then the system may not be able to accommodate it, thus leading to non-zero PNS values. Therefore, in this case, the system has an Exposure Index of α.

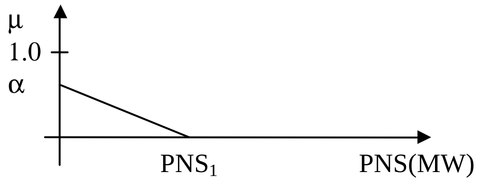

Figure 1: Illustration of PNS membership function.

Once this index is obtained for every period in the horizon using the model detailed in reference [15], we assign the plan under analysis a risk index given by (10) in which $I\exp_p$ is the Exposure Index in period p.

$$I\exp = \frac{1}{np}.\sum_{p=0}^{np-1} I\exp_p \qquad (10)$$

4.5 Mathematical Model

The transmission expansion-planning problem can now be formulated by (11-15). In this formulation, f represents the vector of criteria and X is a set of installations selected to be built or expanded over the horizon. X is in fact a subset of a larger set corresponding to a list of installations, namely including lines and substations, provided by the planner (15) and that one admits to build or expand. Each discrete element of this list is not assigned *a priori* to a particular period of the horizon. The solution algorithm will address this issue when selecting and locating the most adequate installations along the horizon.

In this problem, Y represents operation variables as generations, voltage phases and active flows in each period. Constraints (12) express operation conditions for each period and they join both investment and operation variables since, for a given period, a set of new installations will already be available. These constraints can be related, for instance, with branch flows or generation-load balance equations. Constraints (13) can be used to model financial limitations of the company, namely in order to impose a maximum number of new installations to build or a maximum investment cost, both of them along the entire horizon or on a yearly basis. Constraints (14) express limits on operation variables, for instance related with branch flows or generations.

$$\min f = [TOC, TIC, EENS, I\exp] \qquad (11)$$

$$\text{subj } A.X + B.Y \le d \qquad (12)$$

$$C.X \le c \qquad (13)$$

$$\text{limits on } Y \qquad (14)$$

$$X \in \{x_1, x_2, ..., x_n\} \qquad (15)$$

5. SOLUTION ALGORITHM

5.1 Addressing the Multicriteria Problem

Some of the four criteria incorporated in this problem have contradictory nature in the sense that minimizing investment costs will certainly degrade reliability and risk indices. This means we are facing a decision problem in which the Decision Maker plays an important role. This kind of problems can be addressed in two main ways. In this first case, the Decision Maker is able, *a priori*, that is without having any insight about the problem, to specify weights to compose the criteria into a single function. This function will then be used to drive the selection of the final solution. Another approach aims at identifying non-dominated solutions that will then be presented to the Decision Maker. Using this information together with a trade-off analysis, he will then select the final solution.

In our case and given the complexity of the problem, it would be too time-consuming to build the entire non-dominated set of solutions. Instead, we adopted an interactive procedure according to which it will be identified an initial non-dominated solution to be presented to the Decision-Maker. This solution is built using the ε-constrained method detailed in [16]. According to this approach, all criteria except one are converted into constraints by specifying aspiration levels. In our case, the Decision Maker specifies aspiration levels for the Investment Costs, TIC^{min} and TIC^{max}, for the Expected Energy Not Supplied, $EENS^{max}$, and for the Exposure Index, $I\exp^{max}$. This results into an auxiliary single criteria problem, corresponding in this case to Operation Costs, TOC. The solution of this problem corresponds to a non-dominated solution of the original four-criteria problem. This non-dominated solution will then be presented to the Decision Maker. If the Decision Maker is not satisfied with it, he can change the aspiration levels used previously and solve the single criteria problem again.

5.2 Solving the Single Objective Auxiliary Problem

The single criteria auxiliary problem referred above is still very complex because it has a combinatorial nature due to the discrete nature of investments. To address this problem we adopted Simulated Annealing, SA, [17, 18]. SA is a metaheuristic, that is a search procedure that analysis successive solutions on the solution space. According to an evaluation function, if a new solution is better than a previous one it will be accepted. If it is worse, it can still be accepted depending on a computed probability of accepting worse solutions. This enhanced search mechanism is used to enable the algorithm to escape from local optima, thus contributing to eliminate a well-known problem of gradient-based techniques. This probability is not fixed a priori but it is computed along the iterative procedure. It is typically larger in the beginning of the process so that it becomes more probable to accept worse solutions, as an attempt to introduce diversity in the search procedure, that is, to investigate different areas of the solution space. As the iterative process develops, this probability gets more reduced, namely because the temperature parameter of the algorithm decreases. This means we are already in a promising area of the solution space from where we will hardly move. In any case, even if a worse solution is accepted, the algorithm always retains the best solution identified so far.

It should also be referred that reference [17] demonstrates that, if the cooling process is sufficiently slow and the number of iteration is large, the SA converges to the global optimum. This theoretical support is another point in favor of Simulated Annealing.

The application of SA to the auxiliary single criterium problem includes a first step to identify and completely characterize an initial solution and to initialize some parameters. Then, we sample a new solution in the neighborhood of the previous one either by:

- sampling an installation from the list provided by the planner and a period of the horizon to commission it;
- sampling an installation already present in the current solution to be eliminated.

After analysing this new solution, there is a testing step to compare it with the previous one, and to accept it or not. Finally, there is a set of rules to refresh parameters and to check for convergence. The application of SA to this expansion problem was implemented as follows:

1) Consider the current transmission/generation system as the initial topology and denote it as x^o;
2) Analyze the current solution:
   a. compute TIC, EENS and $Iexp$;
   b. solve problem (2) to (6) to evaluate the short-term operation costs, TOC;
   c. build the evaluation function EF^o as the sum of TOC and penalizations for TIC, EENS and $Iexp$ if they are out of the ranges specified by the Decision Maker;
   d. assign EF^o to EF^{opt} and to $EF^{current}$;
   e. assign x^o to x^{opt} and to $x^{current}$;
   f. set the iteration counter, ITC, to 1;
   g. set the worse solution counter, WSC, at 0;
3) Identify a new plan x^{new}, in the neighbourhood of the current one. To do this, sample one of the periods in the planning horizon, and then sample a new installation to build, among the ones in the list of possible additions, or to decommission, among the existing ones. A new installation will then be available in subsequent periods;
4) Analyze the new plan:
   a. check if the number of installations to build per period exceeds the specified limit. If it does, discard this solution and return to step 3);
   b. compute OC^{new}, IC^{new}, $EENS^{new}$ and $Iexp^{new}$ and obtain the new value for EF^{new};
5) If $EF^{new} < EF^{opt}$ then,
   a. assign EF^{new} to EF^{opt} and to $EF^{current}$;
   b. assign x^{new} to x^{opt} and to $x^{current}$;
   c. set the worse solution counter, WSC, at 0;
6) If $EF^{new} \geq EF^{opt}$ then,
   a. get a random number $p \in [0.0;1.0]$;
   b. compute the probability of accepting worse solutions $p(x^{new})$ by (16);

$$p(x^{new}) = e^{\frac{EF^{current} - EF^{new}}{K.T}} \qquad (16)$$

   c. if $p \leq p(x^{new})$ then assign x^{new} to $x^{current}$ and EF^{new} to $EF^{current}$;
   d. increase the worse solution counter, WSC, by 1;
7) If WSC is larger than a specified maximum number of iterations without improvements, then go to 9);
8) If ITC is larger than the maximum number of iterations per temperature level then:
   a. decrease the current temperature T by a rate α;
   b. if the new temperature level is smaller then the minimum allowed temperature, then go to 9);
   c. set the iteration counter ITC to 1;

   Else, increase the iteration counter ITC by 1;
   Go back to step 3);
9) End.

5.3 Computation of Long Term Marginal Prices

According to the ideas in [19], once an adequate plan is identified, we compute Long Term Marginal Prices using (17). The LTMP in node k is defined as the impact in operation and investment costs due to a change in the demand in node k in period p. In expression (17), ΔEF is the variation of the evaluation function used to characterize the solutions of the SA algorithm if the load in bus k changes by ΔPl_{kp} in period p. This is due to the variation of operation costs, ΔOC, and investment costs, ΔIC.

$$LTMP_{kp} = \frac{\Delta EF}{\Delta Pl_{kp}} = \frac{\Delta OC}{\Delta Pl_{kp}} + \frac{\Delta IC}{\Delta Pl_{kp}} \qquad (17)$$

Once LTMP are obtained for all nodes and periods in the horizon, we can obtain the Marginal Based Remuneration, MBR, using (18). This expression is established admitting that each load pays and each generator is paid the electricity at the marginal price in the node it is connected to. Due to the geographic dispersion of prices and to the distribution of generation and load, this expression leads to a surplus that can be assigned to the transmission provider.

$$MBR = \sum_{p=0}^{np-1} MBR_p = \sum_{p=0}^{np-1} T_p \sum_{k=1}^{nnodes} LTMP_{pk}.(Pl_{pk} - Pg_{pk}) \text{ €} \qquad (18)$$

In this expression, $LTMP_{pk}$ is the long-term marginal price in period p for node k, T_p is the duration of period p and Pl_{pk} and Pg_{pk} are the load and generation in node k for period p. Finally, np is the number of periods in the horizon and nnodes is the number of nodes of the network.

6. CASE STUDY

6.1 The Portuguese Generation Transmission System

In 2001 the Portuguese system had an installed capacity of 10200 MW, from which 4100 MW were run of river and reservoir hydro plants and 4600 MW were coal, combined cycles and fuel thermal stations. There were also 300 MW in wind parks, 400 MW in small hydros and 800 MW in cogeneration plants, mostly connected to distribution networks. The transmission system comprised 160 nodes and 400 kV north-south and east-west lines, 220 kV lines in the center and northeast and 150 kV lines in the northwest and in the south. The peak power was 7540 MW and the demand was 38000 GW.h.

According to current regulations, the Portuguese TSO has to prepare a 6-year expansion plan and submit it to the Regulatory Agency, ERSE. If approved, ERSE gets somewhat committed to remunerate the corresponding costs by including them in the tariff setting procedure. The first 6-year plan covered the period 2002-2007 and since most of the data is public we used it to build a case study.

6.2 Planning Data

The data used to perform the planning expansion study is publicly available in a document prepared by the TSO every year in which it is characterized the generation/ transmission system [20]. This document regarding 2001 details the main technical characteristics of the power stations as well as the technical data for branches. Apart from this information, the algorithm requires a list of possible installations to build or to reinforce. This list is partially reproduced in Table 1 indicating the type of equipment, the extreme nodes, the capacity and the estimated Investment Cost, IC.

no.	extreme nodes		type	$P_{ij}^{máx}$ (MW)	IC ($\times 10^6$€)
1	167	10	400 kV line	1480.0	11.778
2	49	31	220 kV line	344.0	15.313
3	28	164	150 kV line	234.0	1.99335
4	186	108	150 kV line	277.0	1.6401
5	1	191	400 kV line	1386.0	5.208
6	192	31	220 kV line	344.0	3.63
7	102	189	150 kV line	104.0	0.42
8	68	207	220 kV line	377.0	2.16255
9	28	202	150 kV line	234.0	6.9745
10	213	8	400 kV line	1480.0	5.09935
11	210	79	220 kV line	688.0	2.90475
12	214	169	150 kV line	554.0	3.90085
13	217	171	220 kV line	344.0	3.8102
14	106	107	150/60 kV transf.	170.0	5.38275
15	175	35	400/60 kV transf.	170.0	3.2184
16	171	190	220/60 kV transf.	126.0	6.1522
17	169	187	150/60 kV transf.	170.0	9.2306
18	167	200	400/60 kV transf.	170.0	3.817
19	188	201	400/60 kV transf.	170.0	5.2
20	112	213	400/150 kV autotransf.	450.0	5.0
21	210	211	220/60 kV transf.	126.0	6.1522
22	217	218	220/60 kV transf.	126.0	7.2136
23	215	216	220/60 kV transf.	126.0	4.1246

Table 1. Part of the list of possible investments.

Finally, we considered a 10% return rate to refer costs along the horizon back to the initial year and we specified that the maximum number of installations to build or reinforce each year was 36. This was used to simulate financial constraints imposed by the company budget.

6.3 The Selected 6-year Expansion Plan

The developed algorithm selected an expansion plan that integrates 100 new installations to build or to expand. Table 2 partially reproduces this plan, indicating for the investments in Table 1 the ones that were selected as well as their temporal location. It should be referred that in 2002 the complete plan integrates 36 new installations, 12 in 2003, 27 in 2004, 14 in 2005, 7 in 2006 and 4 in 2007.

2002	2003	2004	2005	2006	2007
1	4	5	8	11	13
3		16	9	12	22
14		17	14	20	23
15			18	21	
15			19		

Table 2. Selected investments and their temporal location.

As detailed in section 5.3, the developed approach also outputs the values of the LTMP along the planning horizon. Table 3 presents the values of the prices in €/kW.h for each year of the planning horizon for some 400 kV nodes of the Portuguese transmission system. It can be noticed that the prices have a peak in the first years of the horizon and tend to decrease in the final years. This is due to the concentration of new installations to be built or expanded in the first years of the planning horizon.

node	2002	2003	2004	2005	2006	2007
Alto Lindoso	0.0366	0.0339	0.0296	0.0275	0.0240	0.0233
Riba de Ave 1	0.0369	0.0341	0.0300	0.0279	0.0243	0.0237
Riba de Ave 2	0.0368	0.0341	0.0299	0.0278	0.0242	0.0236
Riba de Ave 3	0.0371	0.0344	0.0302	0.0281	0.0245	0.0238
Setúbal 1	0.0374	0.0342	0.0306	0.0280	0.0246	0.0368
Setúbal 2	0.0376	0.0343	0.0308	0.0282	0.0247	0.0370
Palmela 1	0.0371	0.0340	0.0305	0.0279	0.0222	0.0202
Palmela 2	0.0373	0.0341	0.0305	0.0279	0.0245	0.0367
Sines 1	0.0366	0.0336	0.0301	0.0276	0.0221	0.0213
Sines 2	0.0365	0.0334	0.0301	0.0276	0.0224	0.0228
Sines 3	0.0366	0.0335	0.0301	0.0277	0.0224	0.0229
Mortágua	0.0382	0.0355	0.0315	0.0292	0.0257	0.0250
Pego	0.0372	0.0343	0.0306	0.0281	0.0240	0.0230
Fanhões 1	0.0382	0.0349	0.0312	0.0284	0.0224	0.0222
Fanhões 2	0.0385	0.0351	0.0315	0.0286	0.0261	0.0234
Fanhões 3	0.0390	0.0356	0.0318	0.0289	0.0260	0.0274
Fanhões 4	0.0383	0.0350	0.0312	0.0284	0.0224	0.0222
Cedillo	0.0423	0.0384	0.0345	0.0322	0.0287	0.0291
Rio Maior 1	0.0378	0.0348	0.0310	0.0285	0.0244	0.0234

Table 3. Long Term Marginal Prices (€/kW.h).

6.4 Cost Recovery Analysis

Table 4 presents global results for the four criteria and for the recovery of costs using the Marginal Based Remuneration. These figures are important as they reflect the ability of long-term marginal prices to address the Revenue Reconciliation Problem referred in Section 3.

For each year of the horizon, this Table includes the values of the Expected Energy Not Supplied both in GW.h and in percentage of the yearly demand. It can be seen that the values are very reduced but tend to increase in the final years due to a more reduced investment effort. Table 4 also includes the yearly values of the Exposure Index. This index is 0.0 or very reduced in the first years, but it increases to 1.0 in 2007. This indicates that in 2007 the system is no longer able to cope with load uncertainties and therefore gets completely exposed to uncertainties. This was not taken as sufficiently serious to justify the rejection of this expansion plan because current regulations allow the TSO to update the expansion plan every two years. Therefore, if a higher load increase is confirmed in the final years of the horizon, there is always the possibility of updating the plan closer to those periods. This mechanism illustrates the close relation between risk and flexibility that we think is becoming crucial nowadays.

	2002	2003	2004	2005	2006	2007
EENS (GW.h)	8.51	13.72	12.33	17.64	24.12	31.59
EENS/Load (%)	0.02	0.03	0.03	0.04	0.05	0.06
Iexp	0.0	0.0	0.188	0.0	0.286	1.0
YSTMR (10^6€)	46.07	44.55	42.61	44.86	114.05	39.58
YLTMR (10^6€)	117.89	96.41	104.21	94.31	143.63	247.49
YOC (10^6 €)	46.07	44.55	42.61	44.86	114.05	39.58
YIC (10^6 €)	212.67	45.82	113.14	58.76	29.78	16.47
YTC (10^6 €)	258.74	90.37	155.75	103.62	143.83	56.05
TC (10^6 €)						808.36
TSTMR (10^6 €)						331.72
TSTMR/TC (%)						41.04
TLTMR (10^6€)						803.94
TLTMR/TC (%)						99.45

Table 4. Global results for EENS, Iexp, costs, marginal remuneration and cost recovery.

This Table also includes the yearly short and long-term marginal remunerations (YSTMR and YLTMR), the yearly operation, investment and total costs (YOC, YIC and YTC). The final aggregated values are the total costs TC (sum of the yearly total costs), the total short and long-term marginal remunerations (TSTMR and TLTMR as sums of the yearly values YSTMR and YLTMR) and the recovery percentages of TSTMR over TC and TLTMR over TC. It is important to notice that Total Costs, TC, are almost completely recovered (99,45%) by the long-term marginal remuneration. It should also be referred that LTMP are closely related with the selected plan, in the sense they reflect investment costs. This means that if new installations not included in the plan were built, the cost recovery percentage would certainly get degraded.

7. CONCLUSIONS

This paper presented an integrated approach to the transmission expansion-planning problem considering four criteria and computing nodal long-term marginal prices. The developed model has a number of important features: it addresses the planning problem in a global way (meaning that it does not consider each period for itself, but temporal couplings are adequately considered), it obtains a technically feasible solution (since investments are represented in a discrete way) and it is able to consider in the decision process the impact of reliability data and uncertainty affecting nodal powers. Finally, it computes long-term marginal prices reflecting investment and operation costs.

Long term marginal prices, as indicated by the case study using a real transmission network, are less volatile than short-term ones, and lead to an almost 100% of cost recovery. This way an important disadvantage arising from the use of short-term prices – the Revenue Reconciliation Problem – is eliminated. Apart from this, the developed model clearly shows the close relationship between investments and tariffs. Investments lead to an improved quality of service and the related costs should be adequately recovered by transmission companies.

The above characteristics show that this kind of approaches can be very useful both for transmission companies and for Regulatory Agencies. Transmission companies can use it to help them building more consistent expansion plans while Regulatory Agencies can use this approach to help them in appreciating the submitted plans and in building more robust tariff schemes. This ultimately means that models as the one described can contribute to bridge the gap between Regulatory Agencies and regulated transmission companies, clarifying their roles and turning the planning process more transparent.

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