A Multiyear Dynamic Approach for Transmission Expansion Planning and Long-Term Marginal Costs Computation

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***Abstract*—This paper presents a multicriteria formulation for multiyear dynamic transmission expansion planning problems. This formulation considers three criteria: investment costs, operation costs, and the expected energy not supplied. The solution algorithm adopts an interactive decision-making approach that starts at a nondominated solution of the problem. This solution is identified transforming two of the three criteria in constraints specifying aspiration levels and using afterwards simulated annealing to deal with the integer nature of investment decisions. After obtaining this first solution, the decision maker can alter the aspiration levels and run the application again to obtain a new solution. Once an expansion plan is accepted, the algorithm computes long-term marginal costs, reflecting both investment and operation costs. These costs are more stable than short-term ones and inherently address the revenue reconciliation problem well known in short-term approaches. The developed algorithm is tested using a case study based on the Portuguese 400/220/150-kV transmission network.**

***Index Terms*—Long-term marginal costs, simulated annealing, tariffs for use of networks, transmission expansion planning.**

NOMENCLATURE

The notation used throughout the paper is detailed as follows.

STMC	Short-Term Marginal Cost.
LTMC	Long-Term Marginal Cost.
ρ_k	Short-term marginal price in bus k.
f	Objective function of an optimization problem.
Pl_k, Pg_k	Active load and generation in bus k.
i, p	Index of load scenarios and periods in the planning horizon.
nsc, np	Number of load scenarios and number of periods.
T_i	Duration of scenario i.
nbuses	Number of buses.
MBR	Marginal-Based Remuneration.
MC	Marginal Cost.
PNS	Power Not Supplied.
G	Penalization of PNS.
c_k	Generation variable cost in bus k.
a_{bk}	DC sensitivity coefficient of the active flow in branch b regarding the injected power in bus k.
Pg_k^{min}, Pg_k^{max}	Bounds on generation in bus k.
P_b^{min}, P_b^{max}	Bounds on the flow in branch b.
m and n	Indices for buses.
P_{mn}	Active flow in branch $m - n$.
$Loss_{mn}$	Estimate of active losses in branch $m - n$.
Loss	Estimate of active losses in all branches.
g_{mn}	Conductance of branch $m - n$.
θ_{mn}	Phase difference across branch $m - n$.
$\gamma, \mu_{mn}, \sigma_k$	Dual variables of an optimization problem.
IC, OC, TC	Investment, Operation, and Total Costs.
EENS	Expected Energy Not Supplied.
Δ IC, Δ OC	Variation of the Investment and Operation costs.
ΔPl_k	Variation of the load in bus k.
x	Solution of the Simulated Annealing Algorithm.
ITC, WSC	Iteration counter and worse solution counter.
T, α	Temperature parameter and cooling rate parameter.
K	Boltzman constant.
EF	Evaluation function of the Simulated Annealing.
ΔEF	Variation of the Evaluation Function.
current	Index of the current solution of the Simulated Annealing.
new	Index of a sampled solution of the Simulated Annealing.
opt	Index the optimal solution of the Simulated Annealing.
rp	Random number or probability.
YSTMR	Yearly Short-Term Marginal Remuneration.
YLTMR	Yearly Long-Term Marginal Remuneration.
YOC, YIC, YTC	Yearly Operation, Investment, and Total Costs.
TSTMR	Total Short-Term Marginal Remuneration.
TLTMR	Total Long-Term Margianal Remuneration.
r	Return rate.

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I. INTRODUCTION

FOR THE LAST 25 years, the electric industry has been experimenting with a liberalization and restructuring process that started in Chile, spread to England and Wales in 1990, and then to other European countries, Australia, New Zealand, Latin American countries, and the United States. Initially, there was a strong accent on market mechanisms on the generation sector and on the liberalization of the access to the networks. As this movement developed, there was a new challenge in decoupling distribution network operation from retailing. This finally introduced competition at the extreme activities of the industry—generation and retailing—while keeping network transmission and distribution areas as natural monopolies.

This unbundling process lead to a new organizational paradigm in which one can identify a number of activities with new actors and remuneration mechanisms:

Generation activities—including generation under normal competitive regime, generation under any special tariff regime (namely, including extra payments to renewables), and the supply of ancillary services;
Network activities—comprising both transmission and distribution wiring activities. In Europe, transmission providers are usually merged with system operators leading to transmission system operators. Regarding distribution, the July 2003 EU Directive requires decoupling distribution wiring activities from retailing and the creation of independent distribution system operators;
Transactions—the commercial relationship between generation and demand is performed by centralized pool markets or by bilateral contracts as well as by a number of financial mechanisms aiming at reducing the risk inherent to short-term activities;
Coordination activities—including technical and regulatory aspects. Security of operation is ensured either by independent system operators (ISOs) or by transmission system operators (TSOs). At a regulatory level, network activities are typically not subjected to competition, thus requiring regulatory mechanisms designed and supervised by regulatory agencies.

Electricity markets implemented in several countries suffered from a short-term drawback in the sense that they failed in transmitting long-term signals to induce investments in new generation and transmission capacity. These facts, together with the peculiarities of the product to be marketed and the difficulties in licensing new transmission lines due to environmental constraints, lead to several well-known and discussed problems just illustrating the difficulties in combining short-term approaches with long-term requirements.

Regarding transmission, expansion plans must now be prepared in a decoupled way from generation and distribution. This means that in some way, transmission networks will now have to run after new users both at the generation and the demand side, introducing a new level of uncertainty regarding the location of connection points. The increasing number of wind parks together with their increasing installed capacity leads to power surplus in some distribution networks that now start to inject in transmission. As the installed capacity increases, connection points start to move from distribution to transmission, creating new challenges to transmission planners.

This new environment still has to accommodate some characteristics typical of transmission expansion problems. They are discrete problems due to the integer nature of investment decisions, and one can easily identify a number of criteria to meet leading to multicriteria formulations. Apart from that, expansion plans should display a multiyear dynamic nature. This means they should neither correspond to a set of yearly plans identified in a sequential and an independent way for each year in the horizon nor a set of individual investments selected to address particular problems in the network. In fact, an investment scheduled for a particular year can have a positive impact in years afterward and can also contribute to solve problems elsewhere in the system, given the interconnected nature of transmission networks.

In view of the referred complexities and of the existing models and algorithms, this paper presents a multicriteria formulation for the transmission expansion planning problem considering investment costs, operation costs, and a reliability index, represented by the Expected Energy Not Supplied (EENS). This problem is solved in an interactive way with the decision maker. The algorithm starts by identifying a first nondominated solution of the multicriteria problem. This solution is built by converting two criteria in constraints specifying aspiration levels. The decision maker has the chance to modify the initially used aspiration levels to improve some specific criteria or allow some other to get degraded in some sort of tradeoff analysis. The algorithm proceeds with subsequent changes of the aspiration levels until the decision maker is satisfied with the current nondominated solution. In each run, a nondominated solution corresponding to an expansion plan is built using simulated annealing, given its ability to preserve the discrete nature of the original problem.

Once this phase finishes, one can compute long-term nodal marginal costs reflecting both operation and investment costs. These values are more stable than short-term ones, given that they include a long-term trend based on investment costs, and they inherently address the revenue reconciliation problem that is usual in short-term applications.

The paper includes overviews on transmission expansion planning and on simulated annealing in Sections II and III, Sections IV and V address regulatory issues and concepts about marginal costs, and Section VI details the transmission expansion planning formulation, the adopted algorithm, and the computation of long-term marginal costs. Section VII presents the results obtained with the application of this formulation to a case study based on the Portuguese transmission 400/220/150-kV grid, and Section VIII draws the most relevant conclusions.

II. Overview of Transmission Expansion Planning

The literature on this topic includes a large number of publications that can be gathered in two large groups:

— formulations to analyze preprepared expansion plans. Most of these formulations correspond to software packages developed by utilities or in research centers closely related with them. As examples, they aim at characterizing expansion plans from the point of view of reliability, transient behavior, or stability. Packages such as TRELSS and CREAM developed by EPRI and several others implemented by CEPEL in Brazil, ENEL in Italy, and EDF in France are examples of these approaches;

— optimization models aiming at building expansion plans according to some criteria. In this case, it is important to mention that there is not a common transmission expansion formulation accepted by all researchers. Different publications describe different models as well as solution algorithms. Traditionally, the expansion formulations included continuous variables to represent the capacity of new branches, thus requiring approximations to obtain a final technically feasible solution. For instance, [1]–[4] describe linear and nonlinear approaches to this problem. Such other papers as [5] and [6] adopt Branch and Bound and Benders Decomposition-based methods in a way to preserve the discrete nature of investments. Some others select investments according to a Merit Index or to a tradeoff relation between investment cost and the resulting benefit [7]–[9].

More recently, several emergent techniques, such as simulated annealing, genetic algorithms, tabu search, and game theory, started to be applied to this problem [10]–[17]. References [10] and [12] describe the application of genetic algorithms to the transmission expansion problem. References [15] and [16] detail the use of tabu search, [11] adopts simulated annealing, and [14] uses grasp. All these models have in common the fact that each solution is evaluated by a cost function reflecting investment costs plus a penalty on unserved energy. It comes clear that if this penalty is high, the plan tends to have larger investment costs displaying a tradeoff between investments and unserved energy. This also means that all these approaches combine in a single function two criteria related with investment costs and reliability requiring some prior knowledge of the maximum price that the consumers are willing to pay for electricity. Finally, [17] corresponds to an initial report on the current paper but not yet considering the full multicriteria approach nor the complete application to the Portuguese transmission system, as included in the present paper.

III. Simulated Annealing—An Overview

Simulated annealing [18], [19] is a metaheuristic optimization procedure that, together with genetic algorithms and tabu search, is specially designed to address combinatorial problems. These approaches usually provide good solutions in the sense that they improve a performance index, but it is not usually possible to guarantee global optimality.

Metaheuristic search procedures move away from one solution by sampling another one that is accepted if it improves the selected performance index. If it is worse, it can still be accepted, depending on a small acceptance probability. This is used to escape from local optima and to make a wider search on the solution space until a more promising area is located. This is an important advantage when compared with traditional gradient-based algorithms. The acceptance probability is progressively reduced to avoid oscillation and to make sure that the search is more chaotic in the beginning and concentrated in a promising area as the algorithm proceeds. The simulated annealing algorithm is summarized below.

1) Select an initial solution $\mathrm{x_0}$ in the solution space X and set the iteration counter ITC at 0.
2) Evaluate $\mathrm{x_0}$ computing the evaluation function $\mathrm{EF(x_0)}$.
3) Assign $\mathrm{x_0}$ to $\mathrm{x^{opt}}$ and $\mathrm{EF(x_0)}$ to $\mathrm{EF(x^{opt})}$ The index opt denotes the best solution identified so far.
4) Sample a new solution xin the neighborhood of the current solution $\mathrm{x_{ITC}}$ at iteration ITC.
5) Testing
   a) if $\mathrm{EF(x) \leq EF(x_{ITC})}$ then assign x to $\mathrm{x_{ITC+1}}$;
   b) if $\mathrm{EF(x) \leq EF(x^{opt})}$, then assign x to $\mathrm{x^{opt}}$ and $\mathrm{EF(x)}$ to $\mathrm{EF(x^{opt})}$;
   c) else
      — get a random number rp in $[0.0; 1.0]$;
      — compute the probability of accepting worse solutions at iteration ITC $\mathrm{rp(ITC)}$ by (1) where K is the Boltzman constant

$$\mathrm{rp(ITC)} = \mathrm{e}^{\frac{\mathrm{EF(x_{ITC})-EF(x)}}{\mathrm{K \cdot Temperature}}} \tag{1}$$

   d) if $\mathrm{rp \leq rp(ITC)}$, assign x to $\mathrm{x_{ITC+1}}$;
6) End if a stopping rule is reached;
   otherwise, let $\mathrm{ITC = ITC + 1}$ and go back to step 4).

Along the algorithm, the temperature is lowered in a slow pace so that the system can evolve to a low-energy state in a clear analogy with thermodynamic cooling problems. Usually, the temperature evolves by levels, meaning that each one is used during a fixed number of iterations. After that, the temperature is lowered by a coefficient α, which is inferior but usually close to 1.0.

IV. Regulatory Aspects

Regulation became a crucial activity in the electricity industry as a way to set targets, to induce improvements on technical and economic behaviors, to impose rules on activities still conducted on a monopoly basis, and to defend consumers. Transmission activities are most widely provided in a monopoly basis, and therefore, they require being regulated from a technical and an economic point of view. In several countries, as in Portugal, the transmission system provider must provide its service according to a number of indices specified by the regulatory agency for several security criteria. This ensures the adequate levels of quality of service while inducing expansion and reinforcement investments. TSOs are then usually obliged to prepare and submit expansion plans to the regulatory agency to guarantee those indices. If approved, those plans will be remunerated by tariffs for the use of transmission networks. This mechanism shows some interesting aspects.

— The link between technical issues and economic aspects becomes clear. Technical security or supply indices determine investments to be remunerated by tariffs.

— Once an expansion is approved, it represents a commitment of the regulatory agency to an evolution of those tariffs along the planning horizon.
— Given the impact of investments in tariffs, it becomes clear that expansion plans have to be built carefully, namely, to defend consumers. If available and ensuring the same technical results, a less costly investment plan will have to be selected.

In Portugal, the TSO has to prepare a transmission expansion plan with a six-year horizon based on forecasts of new generation stations, of new demand from distribution systems, on indications about distributed generation either directly connected to transmission or to distribution, and on the specified security indices. This plan is submitted to the regulatory agency, and it is updated every two years to progressively accommodate more refined forecasts for several parameters affected by uncertainties.

V. Nodal Marginal Costs

A. Definitions

The marginal cost of electricity [20] can be defined as the impact on the objective function of an optimization problem due to a change in the demand (2)

$$\rho_{\mathrm{k}} = \frac{\partial \mathrm{f}}{\partial \mathrm{Pl_k}}. \tag{2}$$

Electricity marginal costs display a geographical nature and can either be short or long term, depending on whether they reflect only short-term operation costs or they include both long-term operation and investment costs. STMC or LTMC can then be used to set STMP or LTMP to be used in tariffs for use of networks.

STMC can be obtained as subproducts of dispatch problems by adequately using dual variables in linearized problems [21], [22]. In this case, they are easily computed, but they are very volatile since they depend on the load level [23], on the configuration in operation, on transmission limits, on generation costs, and on component outages. This volatility leads to the concept of spot prices as time-dependent STMC.

LTMCs reflect operation and investment costs along a multiyear horizon. This means that they should be computed in the scope of transmission expansion planning problems, turning their calculation more complex. LTMCs are more stable than STMC since they include a long-term trend, and they are able to transmit economic signals to induce more efficient uses of the network.

Given the complexity of their computation, there are not numerous examples of their use in real tariff systems. One of the rare examples is the ICRP, adopted in England and Wales and detailed in [24].

When STMC or LTMC are available, we can compute the marginal-based remuneration to assign to the transmission provider as a part of its regulated remuneration. This amount comes from the geographic dispersion of these costs and leads to a surplus coming from expression (3). In this case, we specified that each generator or load is paid or pays the electricity at the nodal cost at the bus to which they are connected. As an example, in (3), we assumed that MCs, short term or long term, were computed for a load scenario or system topology i having duration $\mathrm{T_i}$ and nsc is the number of load scenarios along a year

$$\mathrm{MBR} = \sum_{\mathrm{i}=1}^{\mathrm{nsc}} \mathrm{MBR_i} = \sum_{\mathrm{i}=1}^{\mathrm{nsc}} \mathrm{T_i} \sum_{\mathrm{k}=1}^{\mathrm{nbuses}} \mathrm{MC_{ik}} \cdot (\mathrm{Pl_{ik}} - \mathrm{P_{gik}}). \tag{3}$$

MBR based on STMC is usually reduced when compared with the regulated amount [25], [26] (percentages varying from 10%–20% are reported for different systems) leading to the already referred revenue reconciliation problem. On the contrary, MBR based on LTMC inherently addresses this problem since LTMCs also reflect investment costs.

B. Computation of STMCs

For a given topology and set of loads, STMCs can be obtained solving the problem in (4)–(8). The model includes the following:

— a global balance generation/load (5);
— generation (6) and PNS (7) limit constraints;
— branch flow constraints (8) established with the dc sensitivity coefficients

$$\min \mathrm{f} = \sum \mathrm{c_k} \cdot \mathrm{Pg_k} + \mathrm{G} \cdot \sum \mathrm{PNS_k} \tag{4}$$

$$\mathrm{subj} \quad \sum \mathrm{Pg_k} + \sum \mathrm{PNS_k} = \sum \mathrm{Pl_k} \tag{5}$$

$$\mathrm{Pg_k^{min}} \leq \mathrm{Pg_k} \leq \mathrm{Pg_k^{max}} \tag{6}$$

$$\mathrm{PNS_k} \leq \mathrm{Pl_k} \tag{7}$$

$$\mathrm{P_b^{min}} \leq \sum \mathrm{a_{bk}} \cdot (\mathrm{Pg_k} + \mathrm{PNS_k} - \mathrm{Pl_k}) \leq \mathrm{P_b^{max}}. \tag{8}$$

In this formulation:

— $\mathrm{Pg_k}$ is the generation level in bus k, and $\mathrm{c_k}$ is the corresponding variable cost;
— $\mathrm{Pl_k}$ is the load in node k and PNS represents Power Not Supplied penalized by G;
— $\mathrm{Pg_k^{min}}$ and $\mathrm{Pg_k^{max}}$ are the minimum and maximum generation levels in node k;
— $\mathrm{P_b^{min}}$ and $\mathrm{P_b^{max}}$ are the minimum and maximum active flow levels in branch b;
— $\mathrm{a_{bk}}$ is the dc model sensitivity coefficient relating the active flow in branch b with the injected power in node k.

Once this problem is run, active losses can be estimated by (9). In this expression, $\mathrm{g_{mn}}$ is the branch conductance, and θ_{mn} is the phase difference along branch mn

$$\mathrm{Loss_{mn}} \approx 2 \cdot \mathrm{g_{mn}} \cdot (1 - \cos\theta_{\mathrm{mn}}). \tag{9}$$

The results of the problem in (4)–(8) can now be adjusted to include an estimate of active losses using the algorithm that follows.

1) Solve problem (4)–(8) and set iteration counter itr at 1.
2) Build the nodal injection vector and compute voltage phases using the inverse of the dc model bus admittance matrix.
3) Estimate branch losses using (9) and add half of the losses in branch m-n to the loads in nodes m and n.
4) Solve problem (4)–(8) considering the new load vector and increase itr by 1.
5) Build the nodal injection vector and compute voltage phases using the inverse of the dc model bus admittance matrix.
6) Check convergence by comparing voltage phases in two consecutive iterations. If convergence was not yet reached, return to 3).

Using the results obtained in the last iteration of this algorithm, the STMC in node k is computed using (10). In this expression, ρ_{k} is the STMC at node k, γ is the dual variable of constraint (5), P_{mn} is the active flow in branch m-n, μ_{mn} is the dual variable of an active branch limit constraint, σ_{k} is the dual variable of the PNS constraint in node k, and Loss represents active losses in all system branches

$$\rho_{\mathrm{k}} = \gamma + \gamma \cdot \frac{\partial\,\mathrm{Loss}}{\partial \mathrm{Pl}_{\mathrm{k}}} - \sum \mu_{\mathrm{mn}} \cdot \frac{\partial \mathrm{Pmn}}{\partial \mathrm{Pl}_{\mathrm{k}}} + \sigma_{\mathrm{k}}. \tag{10}$$

VI. Transmission Expansion Planning Algorithm

A. General Aspects

Transmission expansion planning problems have some peculiarities that should be stressed.

— In the first place, they have to accommodate two time scales. A shorter one within which available components are fixed and one wants to evaluate operation costs, namely, related with congestion and active losses, and alonger one where one has to deal with investment decisions.

— These two time scales are interrelated in the sense that operation costs can be reduced by new investments. Apart from this, investments should be seen in a global way since a new component especially selected to address some local problem on a specific year can, in fact, have a positive impact in other years and in other locations given the meshed nature of transmission networks.

— Investment decision variables are discrete, leading to a discrete optimization problem.

— One should keep in mind that load will change along the horizon and that, in most cases, there are several and most usually contradictory criteria. This turns the problem into a multicriteria discrete one.

In the developed formulation, the discrete nature of this problem is preserved since the user specifies a list of possible components to reinforce or build. Each possible reinforcement or new component is characterized by its investment cost, and the algorithm will eventually select it as whole, that is, not as in continuous problems in which one can obtain a value between 0 and 1 for a decision variable. This has the drawback of leading to a technically infeasible solution that, once rounded to the closest integer, would not be, in general, the optimal one.

The investment cost of a plan IC is the sum of investment costs IC_{p}, along the np periods in the horizon, adequately adjusted using a return rate r (11)

$$\mathrm{IC} = \sum_{\mathrm{p}=0}^{\mathrm{np}-1} \frac{\mathrm{IC}_{\mathrm{p}}}{(1+\mathrm{r})^{\mathrm{p}}}. \tag{11}$$

For each period in the horizon, operation costs are determined by solving the short-term dispatch problem in (4)–(8), admitting that the elements in the plan under analysis are available in the selected commissioning years and in subsequent periods. This means solving as many short-term dispatch problems as the number np of periods. The total operation cost will be the addition of the yearly costs adjusted in a similar way to (11).

The developed formulation also considers a reliability index since investments can also be driven by the degradation of reliability. In our case, we used the EENS, computed for each period using a pseudochronological simulation described in [27].

As a result, a plan is characterized by the OC, IC, and EENS, leading to a multicriteria problem.

B. Dealing With the Multicriteria Problem

The problem under analysis is very complex due to its integer nature and its size. This prevents using several methods to deal with multicriteria problems, namely, ones that build the nondominated frontier to be presented to the decision maker. In this case, the decision maker could conduct a tradeoff analysis to get more insight about the set of nondominated solutions and finally select one of them.

In our case, we adopted an interactive approach that does not require the knowledge of the nondominated frontier and that is able to address a generic problem as (12)–(16). In this formulation, f is the vector of criteria, Y are short-term operation variables (generation, branch flows, etc.), X represents the discrete list of reinforcements or expansions, (13) are operation constraints for every year of the horizon, and (14) represents limits on the number of reinforcements or expansions per period or limits related with the available amount of money to invest per year. Finally, (15) represent operation and technical limit constraints, and (16) enumerate the available transmission capacities related with possible investment decisions

$$\min \mathrm{f} = [\mathrm{OC}, \mathrm{IC}, \mathrm{EENS}] \tag{12}$$
$$\mathrm{subj} \quad \mathrm{A} \cdot \mathrm{X} + \mathrm{B} \cdot \mathrm{Y} \le \mathrm{d} \tag{13}$$
$$\mathrm{C} \cdot \mathrm{X} \le \mathrm{c} \tag{14}$$
$$\text{limits on } Y \tag{15}$$
$$\mathrm{X} \in \{\mathrm{x}_1, \mathrm{x}_2, \ldots, \mathrm{x}_{\mathrm{n}}\}. \tag{16}$$

The interactive approach starts by building a first nondominated solution using the ε-constrained method detailed in [28]. This method requires converting all objectives but one in constraints using aspiration levels. This leads to an integer single objective problem. In our implementation, the decision maker specifies aspiration levels for the investment cost and for EENS, and the identified nondominated solution is then presented to the decision maker. If he is not satisfied, he can change the aspiration levels, imposing an improvement of some criteria or admitting a degradation of another one. This is iterated until the decision maker is satisfied with the solution.

This solution approach is conceptually different from the one described in several references, for instance, in the ones referred to in the last paragraph of Section II. In these cases, two criteria—investment costs and unserved energy—were combined in a single objective function requiring *a priori* the specification of the penalty on load curtailment. The approach adopted in this paper does not require this *a priori* value. Instead, it gives the planner a more intervening role in appreciating a plan and eventually changing aspiration levels to build a new solution more in accordance with his requirements.

C. Identification of Nondominated Solutions

The single objective problem resulting from the application of the ε-constrained method still has an integer nature. To preserve this characteristic and to ensure that the solutions to be obtained are technically feasible and implementable, we adopted simulated annealing. This algorithm uses a list of expansions and reinforcements from which it samples components to build and the corresponding year. According to the ideas in Section III, the algorithm organizes elements of the list of expansions and reinforcements in a structured multiyear dynamic plan as detailed below.

1) Consider the current transmission/generation system as the initial topology and denote it as $\mathrm{x^o}$.
2) Analyze the current solution:
   a) Compute the IC and the EENS.
   b) Solve problem (4)–(8) to evaluate the short-term OC for the current topology.
   c) Build the evaluation function $\mathrm{EF^o}$ as the sum of OC and penalizations for IC and EENS, in case they are out of the ranges specified by the decision maker.
   d) Assign $\mathrm{EF^o}$ to $\mathrm{EF^{opt}}$ and to $\mathrm{EF^{current}}$.
   e) Assign $\mathrm{x^o}$ to $\mathrm{x^{opt}}$ and to $\mathrm{x^{current}}$.
   f) Set the iteration counter (ITC) to 1.
   g) Set the worse solution counter (WSC) at 0.
3) Identify a new plan $\mathrm{x^{new}}$, in the neighborhood of the current one—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 limit for the number of installations to build per period is exceeded, if the limit for yearly investments is exceeded, or if the global investment limit is exceeded. If it does, discard this solution and return to 3).
   b) Compute $\mathrm{OC^{new}}$, $\mathrm{IC^{new}}$, and $\mathrm{EENS^{new}}$ and obtain the new value for the evaluation function, $\mathrm{EF^{new}}$.
5) If $\mathrm{EF^{new}} < \mathrm{EF^{opt}}$, then do the following.
   a) Assign $\mathrm{EF^{new}}$ to $\mathrm{EF^{opt}}$ and to $\mathrm{EF^{current}}$.
   b) Assign $\mathrm{x^{new}}$ to $\mathrm{x^{opt}}$ and to $\mathrm{x^{current}}$.
   c) Set the WSC at 0.
6) If $\mathrm{EF^{new}} \geq \mathrm{EF^{opt}}$, then do the following.
   a) Get a random number $\mathrm{rp} \in [0.0; 1.0]$.
   b) Compute the probability of accepting worse solutions $\mathrm{rp(x^{new})}$ by (17)

$$\mathrm{rp(x^{new})} = \mathrm{e}^{\frac{\mathrm{EF^{current}} - \mathrm{EF^{new}}}{\mathrm{K \cdot T}}}. \tag{17}$$

   c) If $\mathrm{rp} \leq \mathrm{rp(x^{new})}$, then assign $\mathrm{x^{new}}$ to $\mathrm{x^{current}}$ and $\mathrm{EF^{new}}$ to $\mathrm{EF^{current}}$.
   d) Increase the WSC by 1.
7) If WSC is larger than a specified maximum number of iterations without improvements, then go to 9).
8) If the ITC is larger than the maximum number of iterations per temperature level, then do the following.
   a) Decrease the current temperature level 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 ITC to 1.
   Else, increase the ITC by 1;
   go back to 3).
9) End.

D. Computation of LTMCs

Given the integer nature of investments, it is not correct to use a differential-based expression like (2) to compute LTMC. Therefore, using the ideas in [29], we compute an approximation of LTMC using (18). For node k, load $\mathrm{Pl_k}$ is increased by $\Delta\mathrm{Pl_k}$, and the expansion-planning algorithm is run to identify the most adequate plan and to evaluate the impacts on operation and investment costs, OC and IC, regarding the initial solution, that is, to evaluate $\Delta\mathrm{OC}$ and $\Delta\mathrm{IC}$

$$\mathrm{LTMC_k} = \frac{\Delta\mathrm{EF}}{\Delta\mathrm{Pl_k}} = \frac{\Delta\mathrm{OC}}{\Delta\mathrm{Pl_k}} + \frac{\Delta\mathrm{IC}}{\Delta\mathrm{Pl_k}}. \tag{18}$$

VII. Case Study

A. Portuguese Generation/Transmission System

The developed algorithm was tested using a case study based on the Portuguese generation/transmission system according to its configuration in 2001. This configuration was selected as the initial one since it was also used by the Portuguese transmission company to prepare a six-year expansion plan submitted to the regulatory agency.

By 2001, the Portuguese generation/transmission system [30] had 159 nodes and a peak demand of 7540 MW. The installed capacity was 10 171 MW grouped in 8757 MW in large stations and 1414 MW in small hydros, wind parks, and cogeneration stations, mostly connected to distribution networks and having subsidized tariffs. The 8757 MW correspond to a mix of hydro stations (3903 MW), coal thermal plants (1776 MW), fuel oil/gas turbine stations (1852 MW), fuel oil/natural gas stations (236 MW), and natural gas stations (990 MW).

In 2001, the transmission system comprised three voltage levels:

— north–south and west–east 400-kV lines with two 400-kV links with the Spanish grid (in the north and center). In 2004, a third 400-kV link with the Spanish grid located in the south was commissioned;
— 220-kV lines in the central and northeast parts of the country. There were three 220-kV links in the northeast;
— 150-kV lines in the south and northwest.

As required by Portuguese regulations, the expansion planning exercise aimed at building a six-year plan—2002–2007. We used data in [30], a demand increase of 3.5% per year, a maximum number of 36 new additions per year, to simulate financial constraints and a 10% return rate. We also admitted that the generation system was going to evolve as indicated in [30] from 2002 to 2007: a new natural gas station (4×292 MW starting at 2002, 2004, 2005, and 2006) and new hydro stations (2×118 to start in 2002 and 178 MW to start in 2004).

B. List of Possible Lines and Substations to Build

Due to the new generation stations and to the evolution of the distribution system along the six-year horizon, it will be necessary to connect 59 new nodes. It is also important to stress that there are plans to increase the installed capacity in wind parks up to 3500 MW by 2010. Some of these wind parks will have a direct impact on the transmission system because they will be directly connected to transmission substations. The remaining ones will have a indirect impact either because the demand of some distribution networks seen by the transmission system will be reduced while some other distribution networks will become self-sufficient or the flows will, in fact, be reversed toward the transmission grid.

The expansion exercise used a list with 180 possible investments that are partially enumerated in Table I. For each of them, Table I indicates the extreme buses, the type of investment, the transmission capacity, and the investment cost. To enlarge the solution space, that is, to increase the combinatorial level of the problem, we admitted that each element in this list can be used twice, that is, lines or transformers can be installed in parallel.

C. Transmission Expansion Plan for 2002–2007

The most adequate plan identified by the algorithm described in Section VI includes 100 investments distributed as follows: 36 in 2002, 12 in 2003, 27 in 2004, 14 in 2005, seven in 2006, and four in 2007. Table II shows part of this plan, indicating for each investment the corresponding commissioning year. The investments in Table II correspond to the ones in Table I that were incorporated in the final plan.

D. LTMCs

As indicated in Section VI-D, the LTMCs can be computed as soon as an expansion plan is selected by evaluating the impact in operation and investment costs of varying the demand. These marginal costs can then be used to set LTMP. Table III indicates the values of LTMCs (in kilowatthours) along the six-year horizon for several buses of the 400/220/150-kV grid.

TABLE I
PART OF THE LIST OF POSSIBLE INVESTMENTS

no.	extreme buses		type	$P_{ij}^{máx}$ (MW)	IC (x10^6€)
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 II
SELECTED INVESTMENTS AND THEIR TEMPORAL LOCATION

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 III
LTMCs (IN kW.h)

bus	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 IV
GLOBAL RESULTS FOR PNS, COSTS, AND REMUNERATIONS

	2002	2003	2004	2005	2006	2007
EENS (GWh)	8.51	13.72	12.33	17.64	24.12	31.59
EENS/Demand (%)	0.02	0.03	0.03	0.04	0.05	0.06
YSTMR (x10^6 €)	46.07	44.55	42.61	44.86	114.05	39.58
YLTMR (x10^6 €)	117.89	96.41	104.21	94.31	143.63	247.49
YOC(x10^6 €)	46.07	44.55	42.61	44.86	114.05	39.58
YIC (x10^6 €)	212.67	45.82	113.14	58.76	29.78	16.47
YTC (x10^6 €)	258.74	90.37	155.75	103.62	143.83	56.05
TC (x10^6 €)						808.36
TSTMR (x10^6 €)						331.72
TSTMR/TC (%)						41.04
TLTMR (x10^6€)						803.93
TLTMR/TC (%)						99.45

E. Cost Recovery Analysis

Finally, using the LTMP, the LTMR was computed, and a cost recovery analysis was conducted. Table IV displays the final aggregated values.

This table includes the following information:

— the yearly EENS and its percentage regarding the demand. This percentage is quite reduced, although it increases as the planning horizon develops;

— the YSTMRs and YLTMRs obtained using (3) with STMP and with LTMP;

— the YOC, YIC, and YTC;

— the TC and the TSTMRs and TLTMRs as sums of the yearly amounts. All costs and remunerations are referred to the initial year using the referred 10% rate;

— the percentage of TC recovered by TSTMR (41.04%) and by TLTMR (99.45%).

VIII. CONCLUSION

In this paper, we described an integrated approach to identify adequate transmission expansion plans together with setting the tariffs for use of transmission networks based on LTMCs. These two issues have a close relation because in several countries, transmission companies are remunerated according to their costs. This means that investments should be adequately selected as they have a direct impact in consumer tariffs.

The described approach identifies expansion plans in the scope of a multicriteria formulation that builds nondominated solutions using the ε-constrained method and simulated annealing. The use of this metaheuristic enabled us to address the integer nature of investment decisions and to build realistic and technically feasible solutions corresponding to sets of equipments to build organized in a multiyear dynamic expansion plan. The results obtained with this model indicate that LTMPs can almost completely cover the incurred operational and investment costs. This means this approach inherently addresses the revenue reconciliation problem that is usual when short-term approaches are used.

This kind of approach is useful both for transmission companies and regulatory agencies given the link between plans and tariffs referred to above. In this sense, it can be very useful as a way to ensure or increase the quality of service in modern power systems and to set the corresponding appropriate levels of tariffs for use of networks.

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