Market Power Mitigation in Transmission Expansion Planning Problems

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***Abstract*—The exercise of market power through network constraints in electricity markets can lead to high energy prices far from competitive prices. Traditional transmission expansion planning problem formulations do not consider strategic behavior of market agents. Therefore, they cannot capture the potential exercise of market power. In this paper, a predictor-corrector iterative algorithm is proposed to deal with market power mitigation in market-oriented transmission expansion planning problems. The predictor step consists of the solution of an equilibrium market model based on the conjectured supply function. The corrector step is a conventional transmission expansion planning posed as a mixed integer linear programming problem, where the feasible region is dynamically updated taking into account the results from the predictor step. Lerner index and other indices are used to quantify the potential market power. The algorithm finds the minimum cost expansion plan that avoids the exercise of market power through network congestion. The cost of this expansion plan is only slightly greater than the cost of a conventional expansion plan. The approach is illustrated using the 6-Bus Garver and the IEEE-24 RTS test systems.**

***Index Terms*—transmission expansion planning, market power indices, market equilibrium models, predictor-corrector iterative scheme**

I. Notation

Indices and sets

- f, h, F Index and set for firms, $f, h \in F$.
- g, G Index and set for generators, $g \in G$.
- i, j Indices for iterations in the proposed algorithm.
- k Index for lines in the corridor connecting nodes s and r. The range of index k can has a different value for each corridor (s, r). It is a local index for each corridor.
- $l, L^{(i)}$ Index and set for lines at iteration $i > 0$, $l \in L^{(i)}$. $L^{(i)} = L^{(0)} \cup E^{(i)}$, includes the initial lines $L^{(0)}$ and the new lines (r, s, k) proposed in the expansion at iteration i, $E^{(i)}$. A value of l is assigned to each line (r, s, k), the indices l and (r, s, k) are interchangeable.
- r, s, N Indices and set for nodes, $r, s \in N$. $|N|$ is the total number of nodes in the system.
- $E^{(0)}$ Set of all candidate lines. $E^{(0)} = \{(r, s, k)|$ line k in the corridor from node r to node s $\}$, k is a local index that can take different values within each corridor. $|E^{(0)}|$ is the total number of candidate lines.
- $E^{(i)}$ Set of new lines proposed in the expansion at iteration $i > 0$.
- $L^{(0)}$ Set of initial lines in the system (prior to the transmission expansion).
- G_s Set of generators at node s.
- $G_{s,f}$ Set of generators at node s belonging to firm f.
- G_f Set of generators belonging to firm f.
- $L_r^{(i)}$ Set of lines connected to bus r at iteration i.
- $L_{r,s}^{(i)}$ Set of lines connecting node r and node s at iter. i.
- Ψ Set of all the possible expansion plans using the candidate lines, $E^{(i)} \in \Psi$, $\forall i$. For each line there are only two options (built or not built), then the total number of expansion plans is $|\Psi| = 2^{|E^{(0)}|}$.

Parameters

- $b_{s,r,k}$ Susceptance of line (s, r, k), (p.u.).
- $g_{s,r,k}$ Conductance of line (s, r, k), (p.u.).
- $B_{f,s}$ Slope of the Conjectured Supply Function (CSF) for firm f at node s, (MW/(€/MWh)).
- C_g Marginal generation cost for unit g, (€/MWh).
- $K_{s,r,k}$ Investment cost for line (s, r, k), (p.u.).
- $PTDF_{s,l}^{(i)}$ Power Transfer Distribution Factor for node s and line l at iteration i, (p.u.). Power flow in line l when a unitary power injection is applied at node s.
- X_g Rated capacity of generator g, (MW).
- $Y_l^{max}, Y_{(s,r,k)}^{max}$ Capacity of transmission line l, (r, s, k), (MW). The same value is assumed in both ways. Indices l and (r, s, k) are interchangeable, there is a correspondence one-to-one between both sets.
- σ Scale factor to make the operation cost $(C_g \cdot x_g^{(i)})$ comparable to the investment cost of lines $(K_{s,r,k} \cdot \omega_{s,r,k}^{(i)})$, (hours).
- Γ_s Constant in the inverse demand function, (€/MWh).
- Φ_s Inverse demand function slope, ((€/MWh)/MW).

Variables

- $a_s^{(i)}$ Amount of power sold (positive) or purchased (negative) by the arbitrager (ISO) at node s and iteration i, (MW).
- $e_{f,r}^{(i)}$ Sales of firm f at node r iteration i, (MWh).
- $f_{s,r,k}^{(i)}$ Lossless power flow in line (s, r, k) at iter. i, (MW).
- $p_r^{(i)}$ Net power injection at node r iteration i, (MW).
- $pj_s^{*(i)}$ Transmission cost from the reference node to node s at iteration i (€/MWh), where superscript "$*$" stands for variable value at equilibrium.
- $q_{s,r,k}^{(i)}$ Power losses in line (r, s, k) at iteration i, (MW).
- $x_g^{(i)}$ Generation of unit g at iteration i, (MW).

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$y^{(i)}_{r,s,k}$ Power from node r to node s through line k in corridor (r,s) at iteration i, (MW).
$\delta^{(i)}_s$ Voltage phase angle at node s and iteration i, (rad).
$\theta^{+(i)}_l, \theta^{-(i)}_l$ Dual variables for the constraints on the power flow in line l in the Independent System Operator (ISO) problem at iteration i, (€/MWh).
$\lambda^{*(i)}_s$ Energy price at node s and iteration i, the "*" indicates the value at equilibrium, (€/MWh).
$\lambda^{(i)}_{f,s}$ Energy price at node s, estimated by firm f at iteration i, (€/MWh).
$\mu^{(i)}_g$ Dual variable for the upper bound generation capacity of generator g at iteration i, (€/MWh).
$\rho^{(i)}$ Energy price at reference node (common value for all the firms) at iteration i, (€/MWh).
$\varphi^{(i)}_f$ Dual variable for demand-generation balance of firm f at iteration i, (€/MWh).

Binary Variables

$\omega^{(i)}_{r,s,k}$ It has value 1 if the candidate line k in corridor from node r to node s is built at iteration i, and value 0 in other case.

Market power indices. They are defined in detail in Sect. IV-C.

$LI^{(i)}_s$ Lerner Index at bus s and iteration i, (p.u.).
$PD^{(i)}$ Average Nodal Price Deviation Index at iter. i, (p.u.).
$NC^{(i)}$ Network Congestion Index at iteration i, (p.u.).

II. Introduction

In current electricity markets and under certain circumstances, some participants (generators), taking advantage of network constraints, can influence energy prices, behaving strategically and exercising what is known as market power [1], [2]. A transmission expansion planning problem can help to mitigate these scenarios by incorporating into its formulation the strategic behavior of market participants. The problem of Transmission Expansion Planning (TEP) has been extensively studied in the literature, as it is illustrated in the reviews [3] and [4]. Several recent works focus on intermittent renewable energy integration into TEP formulations [5]–[8] or even distributed generation [9]. Some other studies address the integration of energy storage into TEP formulations, as in [10] and [11], or the impact of demand flexibility [12].

Based on Conventional TEP (CTEP) formulations [13], [14], transmission network expansion models in market oriented environments have sought to integrate market influence in different ways. For instance, the authors in [15] consider some simplifications for market behavior simulation combined with a CTEP approach. The authors in [16] propose to expand the transmission network through increased generation where the resulting problems are solved through a Mixed Integer Linear Programming (MILP) approach assuming perfect competition among generators. Methods that propose two or three levels programming approaches seek to integrate generation and/or transmission expansion planning along with market constraints into one single problem [17]. However, these approaches do not provide optimal solutions regarding the exercise of market power based on network congestion.

There are few studies on how the effect of market power can be integrated into CTEP formulations. For instance, in [18], the authors propose a mixed-integer bi-level linear programming problem for transmission planning in imperfectly competitive markets. The authors propose this approach to give insights of transmission investments considering the influence of market power. They use a MILP formulation and compare the solution in two stages: a first stage in which all generators behave perfectly competitive, and a second stage involving imperfect competition.

A multi-level approach is proposed in [19] for generation and transmission expansion. An equilibrium model is used for the day-ahead market at the lower level while the intermediate level formulates the equilibrium in generation capacity expansion. Finally, the upper-level model formulates the transmission expansion planning investment problem. The authors in [20] propose a three level formulation where the interactions among market agents is modelled as an EPEC which is solve through a diagonalization method using an iterative algorithm. Özdemir et al. [21] also proposed a market equilibrium problem for maximization for generators profit, consumer surplus, and transmission surplus for the grid operator. Reference [22] derives the optimal expansion of the transmission network by modeling the strategic behaviors of the generating units. Then, they calculate the social welfare before and after a specific transmission upgrade using the relevant bidding data. In [23], the authors propose two approaches for modeling market power in transmission planning. However, the proposed approaches are based on some heuristic assumptions. In [24], the authors develop a formulation that can model both market power and strategic generation capacity expansion for the assessment of transmission expansion policies. The impact of transmission capacity expansion on market participants' strategic behavior is studied in [25]. The strategic behavior is modeled through a supply function equilibrium approach.

Nowadays, CTEP formulations require taking into account market conditions, the degree of competition and strategic behavior of different market players, always maintaining a common goal of maximizing profits. The main challenges for these formulations are the development of efficient solution approaches which are robust, and, at the same time, avoid and ad-hoc heuristics. This paper develops a predictor-corrector iterative model that finds the minimum cost transmission expansion in imperfect competitive markets, allowing any level of competition to be simulated, and avoiding the potential exercise of market power through network constraints.

The remaining sections of this paper are organized as follows. The problem settlement and the proposed iterative algorithm are presented in Section III; the market and conventional transmission expansion planning problems are described in Section IV. The steps in the predictor-corrector iterative algorithm are described in detail in Section V. Case studies for the 6-bus Garver system and the adapted IEEE 24-bus Reliability Test System are presented and results discussed in Section VI. Finally, Section VII provides concluding remarks.

III. Problem Settlement, Objectives and Contribution

A power system consisting of a set of: nodes N, transmission lines $L^{(0)}$, and generators G is considered here. The system is assumed to operate as an imperfect market where several firms participate. Each firm owns a set of generators. There are several firms, and each generator is owned by a single firm. Demand at each node s is modeled through a linear inverse demand function [26]. Demand load growth is considered along the planing horizon. It is assumed there is enough generation capacity in the system, but network congestion could arise with demand growth. Moreover, firms can behave strategically and take advantage of the network constraints to exercise market power. Firms can create congestion in certain lines increasing energy prices, far higher than the competitive price, at some nodes.

This work provides a methodology to achieve a transmission expansion plant that can be used as a benchmark for the evaluation of investment proposals. The resulting planning expansion proposal represents the network upgrade that minimizes costs and avoids market power exercise through transmission congestion. In case of a system without any incentive to increase transmission congestion through market power, the solution from the proposed approach is exactly the same solution as for the pure cost minimization model. The main contribution in this work is the development of a predictor-corrector iterative algorithm to find a minimum cost transmission expansion plan that is optimal in the sense that it meets two objectives:

- With the resulting transmission expansion plan firms can not increase their profits by creating network congestion. But it does not avoid the exercise of market power based on other features, such as generation withholding.
- The proposed expansion plan minimizes the cost of building the new transmission lines and energy generation cost while meeting the previous objective.

The algorithm is also computationally efficient. The algorithm is an iterative process in which each iteration consists of two steps:

- The predictor step (the market model). It consists of an equilibrium model in an imperfect market with several firms and a Independent System Operator (ISO) acting as an arbitrager. It is posed as a Mixed Linear Complementarity Problem (MLCP), here it is solved using PATH solver under software GAMS [27]. Network constraints are modeled using Power Transfer Distribution Factors (PTDFs) [26], demand is price responsive through an inverse demand function, and the behavior of each firm is modeled through a Conjectured Supply Function.
- The corrector step is a conventional transmission expansion planning problem (CTEP) considering power losses. It is posed as a MILP problem and solved using CPLEX solver under software GAMS [27].

The models proposed for each step have been previously reported in the literature by several authors. Some examples can be found in [28] for the imperfect market model, and in [13] for the CTEP. Here, those models are adapted to be included in a predictor-corrector iterative algorithm. Both models are summarized in what follows, with particular emphasis on how they have been adapted.

IV. Problem Formulation

In this section, the market and CTEP models are formulated, and indices to quantify the exercise of market power provided.

A. The predictor step: the Market Model

The market model used here corresponds to the one described in [28] and [26]. It consists of three main blocks: *i)* the firms problem, *ii)* the Independent System Operator (ISO = TSO + regulator) problem, and *iii)* the market clearing conditions. It is a network-constrained market equilibrium model posed as a Mix Linear Complementarity Problem (MLCP), that consists of the market clearing conditions and the Karush-Kuhn-Tucker (KKT) conditions of the firms and the ISO.

The decision variables for each firm f are the energy sales at each node r, $e_{f,r}^{(i)}$, and the generation with each one of its generators $x_g^{(i)}$, $g \in G_{r,f}$. Also it contains the auxiliary variables $\lambda_{f,r}^{(i)}$ and $pj_r^{(i)}$, and the dual variables $\varphi_f^{(i)}$ and $\mu_g^{(i)}$. The optimization problem for each firm f is (1)-(3):

$$\max\Big\{ \sum_{r\in N} (\lambda_{f,r}^{(i)} - pj_r^{(i)}) \cdot e_{f,r}^{(i)} - \sum_{r\in N} \sum_{g\in G_{r,f}} (C_g - pj_r^{(i)}) \cdot x_g^{(i)} \Big\} \tag{1}$$

Subject to:

$$\sum_{r\in N} e_{f,r}^{(i)} - \sum_{r\in N} \sum_{g\in G_{r,f}} x_g^{(i)} = 0;\ (\varphi_f^{(i)}) \tag{2}$$

$$x_g^{(i)} \le X_g;\ (\mu_g^{(i)})\ \forall r \in N,\ \forall g \in G_{r,f} \tag{3}$$

$$e_{f,r}^{(i)} \ge 0,\ x_g^{(i)} \ge 0$$

where (1) is the objective function for firm f, the first term corresponds to the incomes by energy sales (nodal energy price $\lambda_{f,r}^{(i)}$ minus cost of transporting from node r to the reference node, $pj_r^{(i)}$), the second term is the generation cost C_g minus the cost of transporting from node r to the reference bus. Eq. (2) sets the balance between energy sales and energy generation for firm f (is a lossless system). And finally (3) stands for the upper bound for the generation capacity of each generator g. The Lagrangian function for each firm f is $\mathcal{L}_f^{(i)}(e_{f,r}^{(i)}, x_g^{(i)}; \varphi_f^{(i)}, \mu_f^{(i)})$. And each firm f has a Conjectured Supply Function (CSF) (4) which estimates its response to other firms sales:

$$-B_{f,s} \cdot (\lambda_{f,s} - \lambda_s^*) + \sum_{\substack{h\in F\\ h\neq f}} (e_{h,s}^{(i)} - e_{h,s}^{*(i)}) = 0 \tag{4}$$

where the superscript "$*$" stands for the value of the variable at equilibrium. $B_{f,s}$ (MW/(€/MWh)) is the slope of the CSF at node s for firm f, allowing to represent a wide range of competition levels, from Cournot ($B_{f,s} = 0$) to perfect competition ($B_{f,s} \to \infty$). The term $\sum_{h\in F, h\neq f} e_{h,s}^{(i)}$ is the value of the sales of all the other firms at node s conjectured by firm f, and $\sum_{h\in F, h\neq f} e_{h,s}^{*(i)}$ is the real value of the sales of the other firms in the equilibrium. The CSF enters the firm's optimization problem (1)-(3) through the nodal price $\lambda_{f,s}^{(i)}$ estimated by firm f at node s :

$$\frac{\partial \lambda_{f,s}^{(i)}}{\partial e_{f,s}^{(i)}} = \frac{-\Phi_s}{1+\Phi_s \cdot B_{f,s}} \tag{5}$$

Values of CSF for a particular system can be difficult to calibrate, but here the CSF is used in a "what if" analysis and not to represent a particular system.

The ISO is in charge of the Transmission System Operation (TSO) and the regulation, its decision variables are $p_r^{(i)}$ (net power injected to node r) and $a_r^{(i)}$ (power injected to node r by regulation). Both $p_r^{(i)}$ and $a_r^{(i)}$ are related by (14). The ISO aims for the efficient allocation of scarce transmission capacity to the most highly valued transmission services, subject to network constraints. The ISO optimization problem is:

$$\max\Big\{\sum_{r\in N}\Big[pj_r^{*(i)}\cdot p_r^{(i)} + (\lambda_r^{*(i)} - pj_r^{*(i)})\cdot a_r^{(i)}\Big]\Big\} \tag{6}$$

Subject to:

$$\sum_{r\in N} PTDF_{r,l}^{(i-1)}\cdot p_r^{(i)} \le Y_l^{\max};\ (\theta_l^{+(i)});\ \forall l \in L^{(i)} \tag{7}$$

$$\sum_{r\in N} PTDF_{r,l}^{(i-1)}\cdot p_r^{(i)} \ge -Y_l^{\max};\ (\theta_l^{-(i)});\ \forall l \in L^{(i)} \tag{8}$$

$$\sum_{r\in N} a_r^{(i)} = 0;\ (\rho^{(i)}) \tag{9}$$

where (6) is the ISO objective function, the ISO gets revenues from the transport cost (first term in (6)) and also for the regulation quantity $a_r^{(i)}$ that uses the nodal price differences, $a_r^{(i)}$ is positive for injections to node r and negative for withdraws from node r. Eqs. (7) and (8) stands for the network constraints using PTDFs. $PTDF_{s,l}^{(i-1)}$ are computed for the network resulting from the CTEP problem (see Section IV-B) at iteration $i-1$, with transmission lines $L^{(i-1)} = L^{(0)} \cup E^{(i-1)}$. And (9) sets that ISO does not generate nor consume any energy, it only moves the energy among nodes.

Here, the ISO is a perfect arbitrager, with access to all nodes, and buying and selling power elsewhere in order to eliminate any price difference among the nodes that are beyond the transmission cost. This price difference is zero when none of the lines are congested. The ISO Lagrangian function is $\mathcal{L}_{ISO}^{(i)}(a_r^{(i)}, p_r^{(i)}; \theta_l^{+(i)}, \theta_l^{-(i)}, \rho^{(i)})$.

The complete market model is (10)-(20), where (10)-(13) correspond to KKT conditions for firms problems, (14)-(18) to the KKT for the ISO problem, and (19), (20) are the market clearing conditions:

$$\frac{\partial \mathcal{L}_f^{(i)}}{\partial x_g^{(i)}} = \varphi_f^{(i)} - \mu_g^{(i)} - (C_g - pj_r^{(i)}) \le 0 \ \perp\ x_g^{(i)} \ge 0,\quad \forall g \in G_f \tag{10}$$

$$\frac{\partial \mathcal{L}_f^{(i)}}{\partial e_{f,r}^{(i)}} = \Gamma_r - \Phi_r\cdot\Big(\sum_{h\in F} e_{h,r}^{(i)} + a_r^{(i)}\Big) - \frac{\Phi_r\cdot e_{f,r}^{(i)}}{1+\Phi_r\cdot B_{f,r}} - pj_r^{(i)} - \varphi_f^{(i)} \le 0 \ \perp\ e_{f,r}^{(i)} \ge 0,\ \forall r\in N \tag{11}$$

$$\frac{\partial \mathcal{L}_f^{(i)}}{\partial \varphi_f^{(i)}} = \sum_{r\in N} e_{f,r}^{(i)} - \sum_{r\in N}\sum_{g\in G_{r,f}} x_g^{(i)} = 0,\ (\varphi_f^{(i)}\ \text{free}) \tag{12}$$

$$\frac{\partial \mathcal{L}_f^{(i)}}{\partial \mu_f^{(i)}} = x_g^{(i)} - X_g \le 0 \ \perp\ \mu_g^{(i)} \ge 0,\ \forall g\in G_f \tag{13}$$

$$\frac{\partial \mathcal{L}_{ISO}^{(i)}}{\partial a_r^{i}} = \lambda_r^{*(i)} - pj_r^{*(i)} - \rho^{(i)} = 0,\ \forall r \in N \tag{14}$$

$$\frac{\partial \mathcal{L}_{ISO}^{(i)}}{\partial p_r^{(i)}} = pj_r^{*(i)} + \sum_{l\in L^{(i)}} PDTF_{r,l}^{(i-1)}\cdot(\theta_l^{+(i)} - \theta_l^{-(i)}) = 0 \quad \forall r\in N \tag{15}$$

$$\frac{\partial \mathcal{L}_{ISO}^{(i)}}{\partial \theta_l^{+(i)}} = Y_l^{\max} - \sum_{r\in N} PTDF_{r,l}^{(i-1)}\cdot p_r^{(i)} \ge 0 \quad \perp\ \theta_l^{+(i)} \ge 0, \forall l \in L^{(i)} \tag{16}$$

$$\frac{\partial \mathcal{L}_{ISO}^{(i)}}{\partial \theta_l^{-(i)}} = Y_l^{\max} + \sum_{r\in N} PTDF_{r,l}^{(i-1)}\cdot p_r^{(i)} \ge 0 \quad \perp\ \theta_l^{-(i)} \ge 0, \forall l \in L^{(i)} \tag{17}$$

$$\frac{\partial \mathcal{L}_{ISO}^{(i)}}{\partial \rho^{(i)}} = \sum_{r\in N} a_r^{(i)} = 0,\ (\rho^{(i)}\ \text{free}) \tag{18}$$

$$\lambda_r^{*(i)} = \Gamma_r - \Phi_r\cdot\Big(a_r^{(i)} + \sum_{f\in F} e_{f,r}^{(i)}\Big),\ \forall r\in N \tag{19}$$

$$p_r^{(i)} = a_r^{(i)} + \sum_{f\in F} e_{f,r}^{(i)} - \sum_{f\in F}\sum_{g\in G_{r,f}} x_g^{(i)},\ \forall r \in N \tag{20}$$

It is worth noticing that (14) sets that the nodal price at node s is equal to the sum of the price at the reference node $\rho^{(i)}$ and the transport cost from the reference bus to node s. And (19) sets the nodal price is given by the inverse demand function. Eq. (20) relates the net power injection into the node r to the regulation power $a_r^{(i)}$, the sales $e_{f,r}^{(i)}$ and the generation $x_g^{(i)}$ at that node.

B. The corrector step: The CTEP model

The CTEP model corresponds to the model described in [13] adapted to be included in the proposed iterative algorithm. The main change for the adaptation is the inclusion of a new constraint to take into account the expansion plans that have been discarded in previous iterations.

Equation (21) stands for the objective function in the Conventional Transmission Expansion Problem (CTEP). It consists of two terms, the first one is the sum of the cost of building new lines. $K_{s,r,k}$ is the cost of building line (s,r,k) and $\omega_{s,r,k}$ is a binary variable with value 1 if the line is built and zero in other case. The second term is the sum of the energy generation cost during a period of duration σ (hours). Constant σ is the amortization period (hours) for the lines built, thus both terms in (21) are in the same units and their values can be compared on the same base.

In the CTEP problem there is no market and no firms, it builds on a classical economic dispatch. It takes into account network constraints including transmission line power losses. The CTEP problem takes as input data at iteration i, the net demand at each node s, $D_s^{(i)} = \sum_{g \in G_s} x_g^{(i)} + a_s^{(i)}$, that are computed using the values $x_g^{(i)}$ and $a_s^{(i)}$ provided by the market model. The previously discarded expansion plans are also data for the CTEP problem. The result from the CTEP problem is the expansion plan that minimizes the objective function (21) and is different, in almost one line, of previously discarded expansion plans. That is, the feasible solution that minimizes the cost of investment in new lines and the operation cost related to generation. If the value of $D_s^{(i)}$ was computed by the firms to create congestion and rise the nodal prices, in the CTEP model, new lines are built such that those nodes can be supplied by cheaper generators, and among all feasible solutions the one with the lowest cost (objective function) is selected. Thus, the iterative algorithm finds the solution of minimum cost. This process can be seen as a predictor-corrector scheme where the market model corresponds to the predictor step (market power exercise can take place), and the CTEP is the corrector step. In the CTEP problem, a new (corrector step) expansion plan is computed to avoid network congestion resulting from the market model (predictor step).

The CTEP problem provides as a result the expansion plan $E^{(i+1)}$. The lines (r, s, k) in this expansion plan are $E^{(i+1)} = \{(r, s, k) | \omega_{r,s,k}^{(i+1)} = 1\}$. For the rest of lines in $E^{(0)}$ (set of all candidate lines) we have $\omega_{r,s,k}^{(i+1)} = 0$, $\forall (r, s, k) \in (E^{(0)} - E^{(i+1)})$. The transmission lines previous to the expansion plan are $(s, r, k) \in L^{(0)}$, these are already built and there is no building decisions on $L^{(0)}$.

The decision variables in the CTEP problem at iteration i are: $x_g^{(i)}$ $\forall g \in G$, $a_s^{(i)}$ and $\delta_s^{(i)}$ $\forall s \in N$, $\omega_{s,r,k}^{(i)}$ $\forall (s, r, k) \in E^{(0)}$, $f_{s,r,k}^{(i)}$, $q_{s,r,k}^{(i)}$ and $y_{s,r,k}^{(i)}$ $\forall (s, r, k) \in L^{(0)} \cup E^{(0)}$. The CTEP problem, at iteration i, can then be formulated as:

$$\min \left\{ \sum_{(s,r,k) \in E^{(0)}} K_{s,r,k} \cdot \omega_{s,r,k}^{(i)} + \sigma \cdot \sum_{g \in G} C_g \cdot x_g^{(i)} \right\} \quad (21)$$

Subject to:

$$\sum_{g \in G_s} x_g^{(i)} + a_s^{(i)} = D_s^{(i)}, \quad \forall s \in N \quad (22)$$

$$a_s^{(i)} \equiv \sum_{(s,r,k) \in L_s^{(0)} \cup E^{(0)}} y_{s,r,k}^{(i)} = \sum_{(s,r,k) \in L_s^{(0)} \cup E^{(0)}} (f_{s,r,k}^{(i)} + \frac{1}{2} q_{s,r,k}^{(i)}), \quad \forall s \in N \quad (23)$$

$$f_{s,r,k}^{(i)} = -b_{s,r,k} \cdot \omega_{s,r,k}^{(i)} \cdot sin(\delta_s^{(i)} - \delta_r^{(i)}), \quad \forall (s, r, k) \in E^{(0)} \quad (24)$$

$$q_{s,r,k}^{(i)} = 2 \cdot g_{s,r,k} \cdot \omega_{s,r,k}^{(i)} \cdot (1 - cos(\delta_s^{(i)} - \delta_r^{(i)})), \quad \forall (s, r, k) \in E^{(0)} \quad (25)$$

$$\{y_{r,s,k}^{(i)}; y_{s,r,k}^{(i)}\} \leq \omega_{s,r,k}^{(i)} \cdot Y_{s,r,k}^{max}, \forall (s, r, k) \in E^{(0)} \quad (26)$$

$$f_{s,r,k}^{(i)} = -b_{s,r,k} \cdot sin(\delta_s^{(i)} - \delta_r^{(i)}), \forall (s, r, k) \in L^{(0)} \quad (27)$$

$$q_{s,r,k}^{(i)} = 2 \cdot g_{s,r,k} \cdot (1 - cos(\delta_s^{(i)} - \delta_r^{(i)})), \quad \forall (s, r, k) \in L^{(0)} \quad (28)$$

$$\{y_{r,s,k}^{(i)}; y_{s,r,k}^{(i)}\} \leq Y_{s,r,k}^{max}, \forall (s, r, k) \in L^{(0)} \quad (29)$$

$$0 \leq x_g^{(i)} \leq X_g, \quad \forall g \in G \quad (30)$$

$$\sum_{(s,r,k) \notin E^{(j)}} \omega_{s,r,k}^{(i)} > 0, \quad \forall j < i + 1 \quad (31)$$

$$\omega_{s,r,k}^{(i)} \in \{0, 1\}, \quad \forall (s, r, k) \in E^{(0)} \quad (32)$$

Constraint (22) is the power balance equation for each node s and it balances the power generation $x_g^{(i)}$, power flows $a_s^{(i)}$ and demands $D_s^{(i)}$ in each node. In this problem, demands $D_s^{(i)}$ are data, and $x_g^{(i)}$, $a_s^{(i)}$ are variables. Power flow in each line $a_s^{(i)}$ is represented by two components: a lossless flow component $f_{s,r,k}^{(i)}$ and a loss component $q_{s,r,k}^{(i)}$, as stated in (23). Lossless power flow, power losses and transmission line capacity limit for lines in the new expansion plan are defined by (24), (25) and (26), respectively. Lossless power flow, power losses and transmission line capacity limit for existing transmission lines in the system (these lines are always present in the system) are defined by (27), (28) and (29), respectively.

It is worth noticing that $E^{(0)}$ is the set of all candidate lines, and binary variable $\omega_{s,r,k}^{(i)}$ selects the transmission lines to be built in the new expansion plan from set $E^{(0)}$. On the other hand, $\omega_{s,r,k}^{(i)}$ is not in (27)-(29) since those lines, $L^{(0)}$ are the existing lines and are always present in the system. The generation capacity limits are represented by (30). Expansion plans previously discarded are taken into account in (31), thus the new expansion plan is different from previous ones. Eq. (31) forces to build at least one new line, but the entire CTEP problem is executed only if the previous expansion plan allows for the exercise of market power through line congestion, thus to solve the problem we need to build at least one new line. Eq. (32) sets that $\omega_{s,r,k}^{(i)}$ is a binary variable, $\omega_{s,r,k}^{(i)}$ is a decision variable with value 1 if the line $(s, r, k) \in E^{(0)}$ is built at iteration i and zero in any other case.

This CTEP problem is formulated as a MILP by linearizing the power losses function around the normal operating point and eliminating the nonlinearities induced by the product of discrete and continuous variables that affect constraints (24) and (25), ensuring and facilitating the convergence, as discussed in [13].

C. Indices for Market Power Analysis

Three indices are considered here for market power analysis: Lerner Index $LI_s^{(i)}$, Network Congestion Index $NC^{(i)}$, and the Average Nodal Price Deviation Index $PD^{(i)}$. These indices are calculated using the results from the optimization problems, they are not included in the optimization problems. The adaptation of these indices to the problem discussed here is described in what follows. Other indices, as for instance the Herfindahl-Hirschman-Index (HHI), could be used but the three considered indices already cover the information needed to discuss the results.

The modified Lerner Index, $LI_s^{(i)}$, for each node s and iteration i, measures the markup of market price, $\lambda_s^{(i)}$, above marginal generation cost (C_g) [29]. For nodes with generation, it is calculated as a weighted average of the modified

Lerner indices for every generating group g according to their maximum generating capacities X_g:

$$LI_s^{(i)} = \frac{1}{\sum_{g\in G} X_g} \cdot \sum_{g\in G} X_g \cdot \frac{\lambda_s^{(i)} - C_g}{\lambda_s^{(i)}}, \quad \forall s \in N \text{ and } G_s \neq \emptyset \tag{33}$$

For nodes without generation its value is $LI_s^{(i)} = 0, \forall s \in N$ and $G_s = \emptyset$.

The Network Congestion Index, $NC^{(i)}$, provides the degree of congestion of the transmission network at iteration i without considering market behavior. It is defined as in [30]:

$$NC^{(i)} = \frac{\sum_{(s,r,k)\in L^{(i)}} |y_{r,s,k}^{(i)}|}{\sum_{(s,r,k)\in L^{(i)}} Y_{s,r,k}^{max} \cdot \omega_{s,r,k}^{(i)}} \tag{34}$$

where $L^{(i)}$ is the set of lines in the system at iteration i. $NC^{(i)}$ ranges from 0 to 1. If $0 < NC^{(i)} < 1$, the network is not globally congested, there is some transmission capacity left but a line or an area may be locally congested. If $NC^{(i)} = 1$ the network is completely congested.

Finally, the Average Nodal Price Deviation Index [30], $PD^{(i)}$, quantifies the impact of transmission congestion on nodal prices (λ_s). $PD^{(i)}$ at iteration i is obtained as the mean absolute deviation between each nodal price, $\lambda_s^{(i)}$, and the system average nodal price $\overline{\lambda}^{(i)} = \frac{1}{|N|}\sum_{s\in N} \lambda_s^{(i)}$ divided by the system number of buses $|N|$ and $\overline{\lambda}^{(i)}$:

$$PD^{(i)} = \frac{\sum_{s\in N} |\lambda_s^{(i)} - \overline{\lambda}^{(i)}|}{|N| \cdot \overline{\lambda}^{(i)}} \tag{35}$$

Any congestion does not indicate the exercise of market power. The index $PD^{(i)}$ is considered here to compute whether the network congestion is in fact affecting prices. If there is transmission line congestion which is not affecting prices then, we say there is no potential market power related to network congestion, and $PD^{(i)} = 0$.

V. PREDICTOR-CORRECTOR PROPOSED APPROACH

The proposed approach combines in an iterative algorithm a market model (10)-(20) and a CTEP model (21)-(32). Thus, the former captures market behavior while the latter incorporates the new network topology resulting from the expansion. The transmission expansion model results in a least-cost expansion solution. The equilibrium problem provides a way to check the exercise of market power through network congestion. The iterative algorithm stops once none of the lines of this new transmission network are congested from the point of view of the market, i.e., the equivalent $PD^{(i)}$ is equal to zero, thereby avoiding market power and favoring a reduction in energy prices.

The overall iterative process is illustrated in Fig. 1 and described in what follows:

i) It starts with the system where all the candidate lines have been built, that is $L^{(0)} \cup E^{(0)}$, and $i = 0$, $PTDF_{s,l}^{(0)}$ are computed for this system and used in the ISO problem. The market model is solved on that system, then we get the nodal prices $\lambda_s^{(1)}$ and the nodal demands $D_s^{(1)}$. The $PD^{(1)}$ index is computed using $\lambda_s^{(1)}$. If $PD^{(1)} = 0$, there is no market power and all the nodal prices have the same value, that kind of solution is referred here as a feasible solution, and we proceed to the next step $i = i+1$. There exists at least one feasible solution, $L^{(0)} \cup E^{(0)}$, but it is the most expensive in terms of lines built (all candidate lines are built). We go to the next step to look for solutions of lower cost.
If $PD^{(1)} \neq 0$, there are differences in the nodal prices, there is exercise of market power and thus there is no feasible solution for this problem, and the algorithm ends here. There is no feasible solution because any other expansion plan is a subset of $E^{(0)}$ and therefore with lower (or the same) line capacities than $E^{(0)}$.

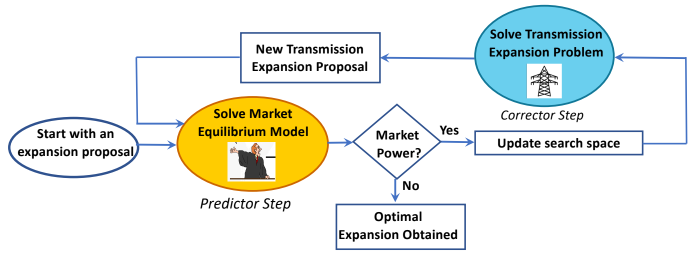

Fig. 1. Flowchart of the proposed method , for $i \geq 2$. This flowchart does not include $i = 1$, iteration 1 is only to check if there exists some solution.

ii) The CTEP problem is solved taking as input data $D_s^{(i)}$, and considering the list of discarded expansion plans ($E^{(j)}, \forall j < i$), then we get $E^{(i)}$ as a result, and $E^{(i)} \neq E^{(j)}, \forall j < i$.

$$\sum_{(s,r,k)\in E^{(i)} - (E^{(i)} \cap E^{(j)})} \omega_{s,r,k}^{(i)} > 0, \forall j < i \tag{36}$$

Constraint (36) is included in the CTEP problem. It sets that the expansion plan at iteration i, $E^{(i)}$, is different from every one of the previous expansion plans $E^{(j)}$, $j < i$. And the difference is that at least one line is in $E^{(i)}$ and it is not in $E^{(j)}$, for each $j < i$. That line can be different for each value of j. Moreover, equation (29) excludes the case where $E^{(i)}$ is a subset of some $E^{(j)}$, $\forall j < i$.
The CTEP problem finds the expansion plan of minimum cost (transmission expansion cost plus generation cost) for the given demand, $D_s^{(i)}$. The value of the CTEP objective function usually increases with the iterations. This is because the previous expansions that have been discarded, each one providing the minimum cost for its demand, but they do not avoid the exercise of market power through network congestion in the market operation. As demand comes from the market problem (predictor step), and can change from one iteration to the next, the value of the CTEP objective function can be a little bit lower in one iteration respect to the previous iteration, but the dominant trend is that the CTEP objective function value increases with the iterations.

iii) The market model is solved for $E^{(i)}$ using in the ISO problem the $PTDF_{s,l}^{(i)}$ computed for the system $L^{(i)} = L^{(0)} \cup E^{(i)}$, as a result we get $D_s^{(i+1)}$ and $\lambda_s^{(i+1)}$. If $PD^{(i+1)} = 0$, then optimal solution found, end. If

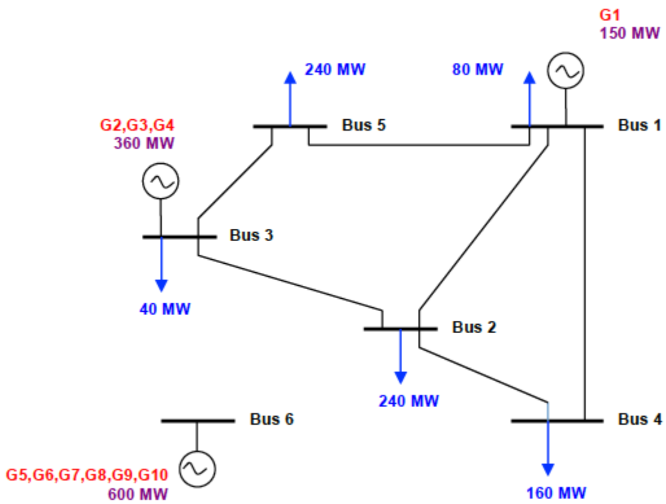

Fig. 2. 6-Bus Garver system

$PD^{(i+1)} \neq 0$, then the expansion plan $E^{(i+1)}$ is added to the list of discarded expansion plans, the iteration index for the next step (CTEP problem) is $i+1$, and go to (ii).

Provided there exists a solution to each of those problems, then the proposed approach converges to the least-cost expansion plan that avoids the potential exercise of market power due to network congestion. Under the worst case scenario, all possible expansion plans are visited except the last one (all the prospective lines are built) that is the most expensive solution in the feasible region

VI. Case Studies

The proposed approach presented in Section V is tested within two different case studies. The first case study corresponds to the 6-bus Garver system [15]. The second case is based on the adapted IEEE 24-bus Reliability Test System [31]. It is assumed that transmission expansion is the responsibility of the System Operator or a regulator whose objective is to achieve the lowest total cost (transmission expansion plus generation cost) while minimizing potential market power exercise.

The algorithm consists of two problems, a MLCP solved using PATH and a MILP solved using CPLEX, both under GAMS [27]. PATH and CPLEX are very efficient algorithms, and the entire iterative process requires only a few iterations, 3-4 iterations for the case studies. Thus, the computational cost of the proposed method is quite low, less than 3 seconds (including the writing time) for the IEEE 24-bus RTS on a laptop with operating system Windows 10, processor AMD FX(tm)-8350 Eight-Core@4GHz and 16 GB RAM.

A. 6-Bus Garver System

The Garver system is shown in Fig. 2. It comprises five nodes with six lines connecting them, four generating units, located at buses 1 and 3, and five loads. Forecast demand, 760 MW, is higher than generation capacity, 510 MW.

Firm $F1$ owns generator located at bus 1 and firm $F2$ owns generators placed at bus 3; these two firms control the total generation in the system. Another firm, $F3$, owns 600 MW of generation at bus 6. This bus is not initially connected to the system. Table I shows the firm, generators location "Node" and units, maximum power output, and marginal cost.

TABLE I
6-Bus Garver. Data for generators (g): location, firm, rated capacity (X_g), and marginal cost (C_g).

Firm (f)	Bus (s)	Unit (g)	X_g (MW)	C_g (€/MWh)
$F1$	1	G1	150	10
$F2$	3	G2	120	20
		G3	120	22
		G4	120	25
$F3$	6	G5	100	8
		G6	100	12
		G7	100	15
		G8	100	17
		G9	100	19
		G10	100	21

TABLE II
6-Bus Garver. Inverse Demand Function

Bus (s)	1	2	3	4	5
Γ_s (€/MWh)	820	2425	410	1617	2418

Constant terms Γ_s (€/MWh) for the demand function at each node s are listed on Table II, and the slope is $\Phi_s = 10$ ((€/MWh)/MW) for all nodes. As this is a long-term planning problem, demand is assumed to be highly inelastic.

Table III provides transmission line data, adapted from [15]. The first two columns show the origin and destination nodes for each line. The third and the fourth columns give transmission line resistance and reactance, respectively. The fifth column shows the line capacity. The cost of building a new line is shown in column six while the last column provides the number of existing lines connecting those nodes.

An analysis with only the initial lines (without expansion), assuming a medium level of competition represented by a CSF slope equal to 10, $B_{f,s} = 10$ (MW/(€/MWh)) $\forall s \in N$, $\forall f \in F$, shows that corridors C_{2-3} and C_{3-5} are congested, Fig. 3 red line. In this configuration, nodal energy prices in some nodes connected by congested lines are very high, for instance in nodes 2 and 5, $\lambda_2 = 1204.70$ €/MWh and $\lambda_5 = 635.00$ €/MWh.

There is a generation deficit and the generator owned by Firm 1, located at bus 1, is in a predominant position. This

TABLE III
6-Bus Garver System. Data for initial lines (already built = 1) and candidate lines. The base value for (p.u.) is 100 MVA.

From (s)	To (r)	$g_{s,r,k}$ (p.u.)	$b_{s,r,k}$ (p.u.)	$Y^{max}_{s,r,k}$ (p.u.)	$K_{s,r,k}$ (M€)	Already Built
1	2	0.59	-2.35	1.00	40	1
1	3	0.92	-3.06	1.00	38	0
1	4	0.39	-1.57	0.80	60	1
1	5	1.18	-4.71	1.00	40	1
1	6	0.35	-1.38	0.70	68	0
2	3	2.96	-7.10	1.00	20	1
2	4	0.59	-2.35	1.00	40	1
2	5	0.78	-3.02	1.00	31	0
2	6	0.83	-3.11	1.00	30	1
3	4	0.40	-1.59	0.82	59	0
3	5	1.18	-4.71	1.00	20	1
3	6	0.49	-1.96	1.00	48	0
4	5	0.38	-1.49	0.75	63	0
4	6	0.83	-3.11	1.00	30	0
5	6	0.38	-1.55	0.78	61	0

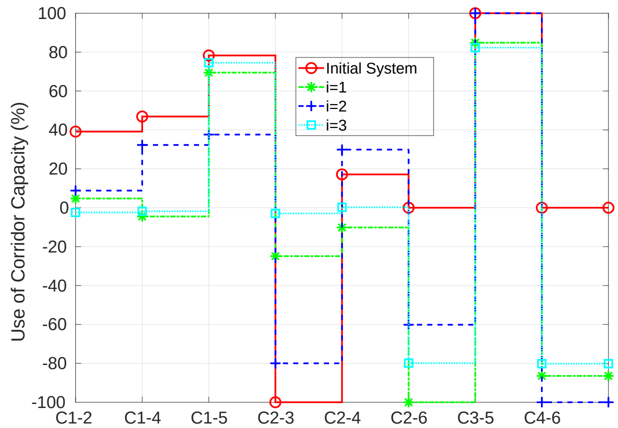

Fig. 3. 6-Bus Garver system, use of corridor capacity (100% or -100% means corridor is congested).

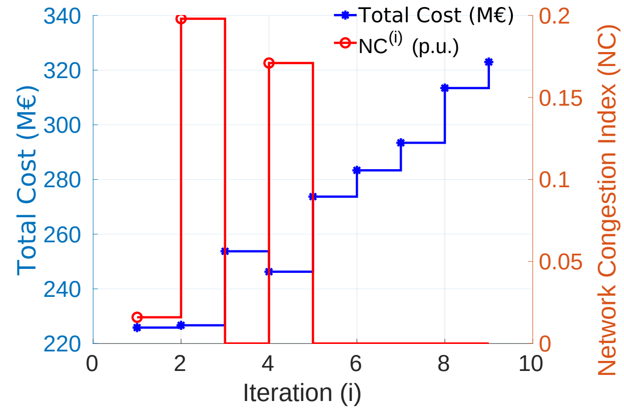

Fig. 4. 6-Bus Garver. Operating cost of generating units plus investment cost in new lines (21) (asterisks) and network congestion index ($NC^{(i)}$) for a CSF slope of $B_{f,s} = 100$ (MW/(€/MWh)) (circles).

TABLE IV
6-Bus Garver System. Candidate corridors and expansion plans for each iteration i

Candidate corridors		Lines Built in the Expans. Plan iter. (i)		
Corridor ($s-r$)	Max. Lines	$i=1$	$i=2$	$i=3$
C_{1-5}	2	0	0	0
C_{2-6}	3	2	3	3
C_{3-5}	2	1	1	1
C_{4-6}	3	2	1	2

generator is exerting market power, it produces 150 MW and has a profit of 128941.68 €/hour, while Firm 2 generates 238.33 MW and has a profit of 1364.76 €/hour. Firm 1 profits are much higher than Firm 2 profits, being Firm 2 power output higher. Interconnection between bus 6 and the rest of the system, following the proposed approach, allows to improve system conditions, including reduced market power and prices, as it is next discussed.

The iterative approach is as follows. We assume an initial set of candidate corridors for the expansion: C_{1-5}, C_{2-6}, C_{3-5} and C_{4-6}. The maximum number of lines for new or existing corridors is limited to three. Corridors C_{1-5} and C_{3-5} already exist in the original system with one installed line, and only two lines are allowed to be expanded.

For $i = 0$, the market model (predictor step) is solved assuming all candidate lines are built. From this problem we get the nodal demands $D_s^{(1)}$, and the values of the indices $PD^{(0)}$ and $NC^{(0)}$ to check that this configuration is feasible and without market power exercise. Those nodal demands are used in the CTEP (corrector step), first iteration $i = 1$, to compute the minimum cost TEP (transmission expansion plus generation cost) for those demands. The resulting expansion plan is listed on Table IV; it comprises 5 lines distributed over 3 corridors. The new expanded system now contains 11 lines distributed over 8 corridors, two of which, C_{2-6} and C_{4-6}, are new. Next, the predictor step, the market model, considering the new expansion plan from the corrector step is solved. The results from this equilibrium problem are shown in Table V. Nodal prices are lower but corridor C_{2-6} is congested (Fig. 3) and $NC^{(1)}$ is higher than zero as can be seen in Fig. 4. This means that there is still potential market power exercise. Therefore, the proposed expansion from the predictor step is not optimal and a new expansion plan is required.

TABLE V
6-Bus Garver System. Nodal prices

Bus $s \rightarrow$		1	2	3	4	5
$\lambda_s^{(i)}$	$i=1$	26.3	26.70	26.60	25.60	26.50
	$i=2$	42.2	30.90	31.20	60.30	41.90
(€/MWh)	$i=3$	26	26.00	26.00	26.00	26.00

For the second iteration ($i = 2$), previous transmission expansion plans ($i = 1$) are taken into account to get a different expansion plan in the corrector step (CTEP problem) through constraint (31). The new expansion plan consisting of 6 lines distributed over 3 corridors is summarized in Table IV. The predictor step is then carried out through the solution of an equilibrium model which considers the new expansion plan listed on Table IV. The new 6-bus system has 11 lines distributed over 8 corridors. Nodal prices, Table V, rise at $i = 2$ respect to $i = 1$ due to the fact that corridors C_{3-5} and C_{4-6} became congested, Fig. 3. $PD^{(2)} > 0$ then the proposed expansion plan is discarded, and a new iteration is required.

Finally, for $i = 3$ all the nodal prices have the same value, $PD^{(3)} = 0$,, Table V, and there are no congested lines, Fig. 4. This is the minimum cost expansion plan that avoids the exercise of market power through network congestion. This expansion plan removes the option for the firms to make additional profits by creating congestion as nodal prices converge to competitive levels. The lines in this expansion plan are listed on Table IV. The values of system average Lerner Index, LI (33), for the initial system and the first three iterations are depicted on Fig. 5. Bus 6 is isolated and it is not included in Fig. 5. At iteration $i = 3$, $LI_s^{(3)} = 0.3798$ for all the nodes, because there are no congested lines and also nodal prices have the same value in all the buses. The value of nodal prices for the solution ($i = 3$) is lower than the value for the initial configuration (5 bus connected and bus $s = 6$ isolated), as market power through network constraints has been removed.

There are more transmission expansion solutions where the NC index is null but the total cost (21) is always higher (or equal) than the value at $i = 3$. Since, at each iteration, the optimization problem provides the solution at minimum cost in the feasible region, and that solution is removed from the feasible region for the next iteration.

Congestion reduction for the 6-bus Garver system is an-

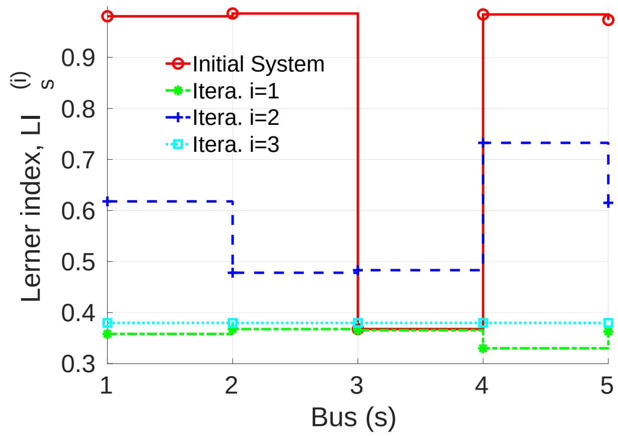

Fig. 5. 6-bus Garver system with $B_{f,s} = 10$ (MW/(€/MWh)) . Bus $s = 6$ is isolated, and it is not represented in the figure. Value of Lerner index $LI_s^{(i)}$, $s = 1, 2, \ldots, 5$ for the initial system and the first 3 iterations $i = 1, 2, 3$.

TABLE VI

6-BUS GARVER: NETWORK CONGESTION INDEX $NC^{(i)}$ AND AVERAGE NODAL PRICE DEVIATION $PD^{(i)}$, FOR $i = 0$ (NO EXPANSION), AND SUCCESSIVE EXPANSIONS ($i = 1, 2, 3$) UP TO THE OPTIMAL ($i = 3$).

Iteration (i)	0	1	2	3
$PD^{(i)}$	0.45234	0.01615	0.19855	0.00000
$NC^{(i)}$	0.73683	0.60652	0.52446	0.51463

alyzed in Table VI through $PD^{(i)}$ and $NC^{(i)}$ for different iterations. NC index shows a network that is not globally congested. As the iterations advance, $NC^{(i)}$ decreases because the network capacity increases (new lines) while the generation capacity remains constant. On the other hand, PD index shows that locally there are problems in the network. In fact, for the initial system the average nodal price deviation is 45% ($PD^{(0)} = 0.45$), something unacceptable from the market point of view. $PD^{(i)}$ decreases to zero at iteration $i = 3$ because price differences among buses are zero.

Values for the discussion of exercise of market power in the 6-bus Garver system are summarized on Table VII. It shows for the initial system (previous to expansion), $i = 0$ that Firm 1 exerts market power, as shown by its profit in comparison to Firm 2. In the following iterations, the exercise of market power by Firm 1 is drastically reduced, while the profit of Firm 3 increases becoming the most profitable firm. Focusing on total net profit, iteration $i = 1$ seems to be the best option since it involves 5.67 M€ less profit than in iteration $i = 3$, however the most relevant figure is the generation cost, and it reaches the minimum value at iteration $i = 3$. The total net profit, sum of firms profit minus total generation cost, is higher at $i = 3$ than in $i = 1$. Solution in $i = 3$ is in fact the optimal solution. Fig. 4 shows that it is the minimum cost transmission expansion plan that avoids the exercise of market power through network congestion. It is worth noticing that our approach is oriented to mitigate market power exercise due to line congestion in transmission expansion planning problems. Other market power issues such as those related to capacity withholding can be addressed in capacity expansion problems.

This first case study, 6-bus Garver, is solved for different levels of competence, from Cournot towards perfect competition. The values used for the slope of the Conjectured Supply Function are $B_{f,s} \in \{0.001, 0.01, 0.1, 1, 10, 100\}$, with the same value for all the firms f and nodes s in each case. Table VIII shows the number of iterations needed to reach the optimal expansion plan for each level of competition considered. For low levels of competition the proposed algorithm provides the same solution as the conventional TEP. When the level of competence rises toward perfect competition the number of iterations and number of new lines built rise and the optimal expansion plan changes.

TABLE VII

6-BUS GARVER: FIRM PROFIT, GENERATION COSTS, AND NET PROFIT, FOR THE INITIAL SYSTEM ($i = 0$, NO EXPANSION), AND SUCCESSIVE EXPANSIONS ($i = 1, 2, 3$) UP TO THE OPTIMAL ($i = 3$).

Iteration (i)	Firm 1 Profit (M€)	Firm 2 Profit (M€)	Firm 3 Profit (M€)	Total net Profit (M€)	Generation Cost (M€)
0 (Starting)	1129.54	11.96	0.00	1141.48	1816.72
1	21.50	11.51	38.14	71.16	103.40
2	42.41	25.94	22.41	90.75	186.36
3	21.13	9.46	45.83	76.75	96.28

TABLE VIII

6-BUS GARVER SYSTEM. OPTIMAL EXPANSION PLAN AND ITERATIONS REQUIRED TO REACH IT FOR SEVERAL LEVELS OF COMPETITION.

Candidate corridors		Lines Built in Optimal TEP					
Corridor	Maxim.	$B_{f,s}$ (MW/(€/MWh))					
($s - r$)	Lines	0.001	0.01	0.1	1	10	100
C1-5	2	0	0	0	0	0	1
C2-6	3	2	2	2	2	3	3
C3-5	2	1	1	1	1	1	1
C4-6	3	2	2	2	2	2	3
Required iter. (i)		1	1	1	1	3	9

The solution from the proposed algorithm has a higher cost than the solution from the CTEP problem without taking into account the market. This additional cost is around 12% or less for the 6-bus Garver case study, as it is shown in Fig. 4, for $i = 1$ (possible network congestion) the total cost is 225.83 M€ and it is 253.74 M€ for $i = 3$, the optimal solution avoiding network congestion. The interesting fact is that the main part of the total cost (around 90%) can not be avoided, and a solution where firms can gain nothing by creating network congestion can be attained just with modifications of relatively small cost. Also the additional cost is much smaller compared to the cost of the network congestion itself.

TABLE IX

GARVER: MAXIMUM DEMAND IN EACH NODE (1 TO 6) [80.00, 203.75, 40.00, 203.75, 407.50, 0.00] MW. THE VALUE OF MAXIMUM DEMAND CORRESPONDS TO A NODAL PRICE OF ZERO.

Candidate corridors		Lines Built CTEP, iter. i		
Corridor ($s - r$)	Max.Lines	$i = 1$	$i = 2$	$i = 3$
C_{1-5}	2	0	0	0
C_{2-6}	3	2	3	3
C_{3-5}	2	2	2	2
C_{4-6}	3	2	2	3
Total		6	7	8

A sensitivity analysis on the inverse demand function has been performed, keeping the slope (elasticity) but changing the maximum possible demand in the nodes, that is changing the constant Γ_s in the inverse demand function. This change in Γ_s can model demand seasonality. In all the cases the sum of the maximum nodal demands is lower than 85% of the total generation. How the demand is assigned to nodes is changed in the sensitivity analysis. Only Tables IX and X are included here as representative results. From these sensitivity

TABLE X
GARVER: MAXIMUM DEMAND IN EACH NODE (1 TO 6) [80.00, 203.75, 40.00, 203.75, 407.50, 0.00] MW. THE VALUE OF MAXIMUM DEMAND CORRESPONDS TO A NODAL PRICE OF ZERO.

Demand N[2,4,5] = [203.75, 203.75, 407.50]				
Node	Nodal Price €/MWh			
	i=0	$i = 1$	$i = 2$	$i = 3$
1	1306.3	318.5	83.4	30.5
2	2221.1	118.2	87.8	30.5
3	25.7	25.8	30.9	30.5
4	1855.0	341.7	181.7	30.5
5	666.0	410.9	48.4	30.5
6	0.0	0.0	0.0	0.0

TABLE XI
ADAPTED IEEE-24 RTS. DATA FOR GENERATORS (g): LOCATION (s), RATED POWER (X_g), AND MARGINAL COST (C_g).

Firm (f)	Node (s)	Gen. (g)	X_g (MW)	C_g (€/MWh)
$F1$	1	G1	192	15
	2	G2	192	14
	7	G3	300	15
$F2$	13	G4	591	15
	14	G5	100	14
	15	G6	215	16
	16	G7	155	15
$F3$	18	G8	400	13
	21	G9	400	14
	22	G10	300	15
	23	G11	660	15

analysis the conclusions are: i) The number of iterations to reach convergence is similar to for all simulations performed for the sentitivy analysis ii) The proposed expansion plans (lines built) do not experience significant changes under the sensitivity analysis, and iii) The proposed algorithm is able to detect when there is no solution.

B. *Second Case Study: Adapted IEEE-24 RTS*

This second case study is based on the IEEE 24-bus RTS described in [31]. It consists of 24 nodes with 34 transmission lines connecting them. The system contains 11 generating units, owned by 3 different firms, and 17 loads. Generating unit locations, their maximum capacities, marginal costs, and the firm that owns each generator are listed on Table XI. Values of the constant term, Γ_s of the inverse demand function (19) for each node s are provided on Table XII.

Similar to the first case study, there is only one existing line per corridor and only three lines per corridor are allowed to be installed. Building corridors connecting nodes that initially were not connected is not considered. The investment costs for new lines are distributed as follows: 20 M€ per line if it belongs to a corridor that connects any node from 1 to 9; 40 M€ per line for connections between any nodes from 11 to 24; for the interconnection corridors (3-24, 9-11, 9-12, 10-11 and 10-12) no new lines may be built and the selected investment cost is 400 M€.

TABLE XII
ADAPTED IEEE-24 RTS. PARAMETERS OF THE INVERSE DEMAND CURVES, (19), AT EACH BUS s, Φ_s = 10 ((€/MWH)/MW) $\forall s \in N$

Bus (s)	1	2	3	4	5	6
Γ_s (€/MWh)	1106	1000	1814	764	736	1386

Bus (s)	7	8	9	10	13	14
Γ_s (€/MWh)	1280	1724	1774	1976	2676	1970

Bus (s)	15	16	18	19	20	
Γ_s (€/MWh)	3184	1024	3356	1836	1310	

TABLE XIII
ADAPTED IEEE-24 RTS. OPTIMAL EXPANSION PLAN AND ITERATIONS REQUIRED TO REACH IT FOR SEVERAL LEVELS OF COMPETITION.

Candidate corridors		Lines Built in Optimal TEP					
Corridor ($s-r$)	Maximum Lines	$B_{f,s}$ (MW/(€/MWh))					
		0.001	0.01	0.1	1	10	100
C_{1-5}	2	2	2	2	2	2	2
C_{6-10}	2	0	0	0	1	1	1
C_{7-8}	2	2	2	2	2	2	2
C_{10-12}	2	1	1	1	1	1	1
C_{11-13}	2	2	2	2	2	2	2
C_{15-21}	2	2	2	2	2	2	2
C_{16-17}	2	0	0	0	1	1	1
C_{16-19}	2	2	2	2	2	2	2
C_{20-23}	2	2	2	2	2	2	2
Required iter. (i)		1	1	1	2	2	2

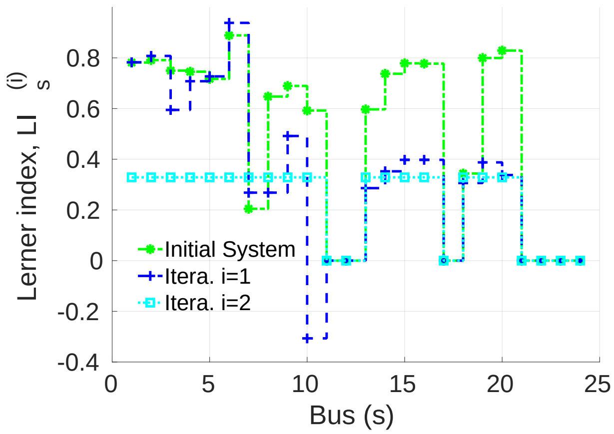

Fig. 6. Adapted IEEE-24 RTS, with CSF slope $B_{f,s} = 10$ (MW/(€/MWh)). Lerner Index, $LI_s^{(i)}$ for each node s, it is zero for nodes without generation.

For illustrative purposes, the original IEEE-24 RTS [31] is adapted here by reducing the capacity of each line to 42% of the original value. As a result, there are some congested lines and high nodal prices for each one of the CSF slope values tested, $B_{f,s} \in \{0.001, 0.01, 0.1, 1, 10, 100\}$ (MW/(€/MWh)). CSF slopes are used in a "what if" analysis.

Table XIII provides the set of candidate corridors, the optimal expansion plan for each level of competition (each CSF slope), and the number of iterations required in each case.

From Fig. 6 it can be seen that the values of Lerner Index $LI_s^{(i)}$ for the optimal expansion plan $i = 2$ are better than for the initial system. The slope of the CSF used for the results in Fig. 6 is $B_{f,s} = 10$ (MW/(€/MWh)), that is close to perfect competition.

The $NC^{(i)}$ index along iterations i for a CSF slope, $B_{f,s} = 10$ (MW/(€/MWh)) is $NC^{(0)} = 0.869$, $i = 0$ corresponds to the initial system previous to expansion, $NC^{(1)} = 0.885$, $NC^{(2)} = 0.852$. And the Average Nodal Price Deviation $PD^{(i)}$ is $PD^{(0)} = 0.314$, $PD^{(1)} = 0.554$, and $PD^{(2)} = 0.000$. The optimal expansion plan is reached in two iterations, $PD^{(2)} = 0.000$. There are no congested lines and no differences among nodal prices. With this expansion plan, firms can gain nothing by creating line congestion.

From the transmission expansion viewpoint, as in the first case study, for levels of competition with CSF slopes $B_{f,s} \geq 1$, the optimal expansion plan obtained has a lightly higher cost than the expansion plan from the CTEP. This additional cost is the cost of building a network where firms can gain nothing by creating congestion. With regard to the $NC^{(i)}$ index the conclusions are analogous to those for the first case study.

VII. Conclusions

There is no single transmission expansion approach that addresses in detail all technical and market issues at once. Traditional centralized methods for transmission expansion do not directly provide optimal expansion plans that reduce market prices and limit potential market power abuse. This work has presented a methodology to achieve a transmission expansion plan that can be used as a benchmark for the evaluation of investment proposals. The resulting planning expansion proposal represents the network upgrade that minimizes costs and avoids market power exercise due to transmission line congestion. Here, it has been proposed an iterative algorithm that combines two steps: *i)* a conventional transmission expansion planning (economic dispatch with network constraints), and *ii)* a market equilibrium model (imperfect market with competitive firms and a ISO as arbitrager). The first step assures physical feasibility: power flows and network constraints. The second step assures no market power by network constraints. The algorithm finds the minimum cost transmission expansion plan that avoids market power by network congestion.

Results for the case studies show the additional cost of a TEP that avoids market power by network congestion is only slightly greater, around 12% or less for the case studies, than the cost of a conventional TEP (with possible market power).

The consideration of intermittent renewable generation, energy storage, and a full AC model of the power network in this approach is a research line of interest for the authors for future research works.

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