Transmission Expansion Planning in Deregulated Electricity Markets for Increased Wind Power Penetration

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***Abstract*-- In this paper, a model for transmission expansion planning (TEP) in deregulated electricity markets is developed, considering transmission congestion, wind power integration and double-sided bidding power-pool operation for both generation and demand. A compromise between the congestion revenue and the investment cost is used to determine the optimal expansion scheme, considering the outage rates of transmission lines. Both the level of congestion and the price deviation in the network are used as the driving indicators for the need of network expansion. The uncertainty in wind power generation introduces the probabilistic locational marginal prices (LMPs) and the estimated congestion revenue for a specific system configuration. The proposed TEP approach is applied on Garver's six bus system and the planning schemes results are assessed.**

***Index Terms*-- transmission expansion planning, electricity markets, power-pool, locational marginal pricing, transmission congestion, transmission security.**

I. Nomenclature

c_{ij}	Cost of a line added to the *i-j* right of way.
γ_{ij}	Susceptance of the line between nodes *i* and *j*.
n_{ij}	Number of new lines added to the *i-j* right of way.
n_{ij}^0	Initial number of lines between nodes *i* and *j*.
$\overline{n}_{ij}$	Maximum number of circuits that can be added in right-of-way *i–j*.
f_{ij}	Active power flow in the *i-j* right of way.
$\bar{f}_{ij}$	Active power flow limit in the *i-j* right of way.
θ_i	Phase angle in node *i*.
S	Branch-node incidence matrix
f	Vector with elements f_{ij}.
g	Vector of active power generation with elements g_κ (generation in bus *k*).
$\overline{g}$	Vector of maximum generator capacity.
d	Vector of active power demand with elements d_k (load in bus *k*).
$\overline{d}$	Vector of maximum demand.
$B_j(d_j)$	Consumer benefit function for a particular customer *j*.
$C_k(g_k)$	Production cost function for a particular supplier *k*.
TR	Congestion revenue.
$\mu_{\mathrm{e,i}}$	Locational marginal price (LMP) in node *i*.
$\mu_{\mathrm{f,ij}}$	Lagrange multipliers with respect to the line *i-j* transmission limits.
σ_{ij}^t	Sensitivity factor for the *i-j* right of way for iteration *t*.
CI	Congestion index.
STD	Standard deviation of LMP in the network.
$STDm$	Standard deviation of mean of LMP in the network.
ε_{CI}	Tolerance rate of the congestion index set by the regulator.
ε_{STD}	Tolerance rate of the price deviation set by the regulator.
P_W	Real power output of a wind turbine.
P_R	Rated power of a wind turbine.
V_W	Wind speed.
V_{CI}	Cut-in wind speed of the wind generator.
V_{CO}	Cut-out wind speed of the wind generator.
Ω	Set of total buses in the system.

II. Introduction

In regulated electricity markets, the transmission expansion planning (TEP) problem consists of minimizing the investment costs in new transmission lines, subject to operational constraints, to meet the power system requirements for a future demand and generation configuration. The TEP problem in deregulated power systems differs from regulated ones regarding the point of view of the transmission planner in two major points: (1) the objectives of TEP in deregulated power systems differ from those in the regulated ones, and (2) the number of uncertainties in deregulated power systems is greater than in regulated power systems. Those system uncertainties can be

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classified into two categories [1]: (i) random uncertainties, such as load, conventional generators' costs and bidding prices, availability of system facilities as well as renewables production and (ii) nonrandom uncertainties, such as generators' expansion or shutting down, transmission expansion costs, etc. The statistics of random uncertainties can derive from older observations but nonrandom uncertainties are not repeatable and cannot be statistically represented.

The main objective of TEP in deregulated power systems is to provide a non-discriminatory and competitive environment for all stakeholders, while maintaining power system reliability [2]. TEP affects the interests of market participants unequally and this should be considered in the transmission planning. Nowadays, the TEP problem has become more challenging because the integration of wind power into power systems often requires more, but less utilized, new transmission lines to be built. Another challenge is that transmission congestion restricts power flow from low cost nodes to high value nodes creating supply–demand price imbalances.

In both regulated and deregulated power markets, the power system should always be operated in such a way that no contingency could trigger cascading outages or another form of instability. Since securing the system against all possible contingencies is clearly impossible, System Operator is only checking all credible contingencies [3]. In transmission expansion problems, the security analysis concerns the satisfaction of the nodal power balance with no violations of the transmission lines maximum flow under both normal and N-1 system condition.

Many methods have been applied to solve the transmission expansion planning problem such as linear programming [4], dynamic programming [5], branch and bound techniques [6], nonlinear programming [7], mixed integer programming [8], decomposition techniques [9], simulated annealing [10], tabu search [11], genetic algorithms [12]-[13] and differential evolution [14]-[15]. Probabilistic methods for the solution of TEP problem include probabilistic reliability criteria [16] and risk assessment [17] methods.

TEP can be classified as static or dynamic according to the treatment of study period [14]. The deterministic approach in static TEP problems aims at minimizing the cost of the new lines added and the cost of the unserved load considering a unique time period on the planning horizon. When multiple years are considered and an optimal expansion along the whole planning horizon is searched, the planning is classified as dynamic. In this case, the mathematical model has time restrictions and the net present value of the expansion costs are minimized along the period investigated.

In this paper, a new model for TEP is developed considering transmission congestion and wind power integration. Power-pool operation with double-sided bidding for both generation and demand is assumed. The static TEP problem is solved with Benders decomposition technique taking into account the line outage rates and wind power generation uncertainty in probabilistic manner. Uncertainty in wind power generation along with the outage rates of transmission lines introduces the probabilistic LMPs and the estimated congestion revenue for a specific system configuration. The DC power flow is followed for the network representation since this model is commonly used in planning studies, especially when highly meshed networks are to be investigated [1], [10], [18]. The level of congestion in the network is used as the driving indicator for the need of network expansion. However, the congestion revenue that is collected from the system operator could be used for financing new investments. A compromise between the congestion revenue and the investment cost is used to determine the optimal expansion scheme. The developed technique is applied to Garver 6-bus test system to illustrate the network planning study.

III. MODEL OVERVIEW

The proposed TEP approach relates the congestion revenue deriving from the power pool market operation planned to be used in new investments with the annualized cost of proposed transmission network reinforcements.

A. Congestion revenue in power pool market

To formulate a power-pool operation market model, first the GenCos (DisCos) submit their marginal cost (benefit) reflected offers (bids) and then the independent power system operator (ISO) and/or power exchange (PX) performs the market clearing process using the DC load flow model from which the clearing prices derive. However, in a strategic bidding, suppliers and consumers may not bid their true marginal cost or benefit functions although the system operator can make a good estimation of their behavior. For that reason, uncertainty is introduced into the producers/consumers bids, which can be considered following normal distribution. Knowing the probability density function of those random uncertainties, several scenarios can be generated using Monte Carlo simulation to represent the uncertain market operations during the planning horizon.

For each typical scenario, the market mechanism is designed to maximize total social welfare:

$$\text{Max} \quad \sum_j B_j(d_j) - \sum_k C_k(g_k) \tag{1}$$

Subject to

$$S^T f + g + r = d \tag{1.1}$$

$$f_{ij} - \gamma_{ij}(\theta_i - \theta_j) = 0 \tag{1.2}$$

$$\left|f_{ij}\right| \le \bar{f}_{ij} \tag{1.3}$$

$$0 \le g \le \bar{g} \tag{1.4}$$

$$0 \le d \le \bar{d} \tag{1.5}$$

$$i, j \in \Omega$$

In the above formulation, constraint (1.1) stands for the power nodal balance equation; constraint (1.2) is the DC power flow model approximation, while constraints (1.3)-(1.5) specify the operational limits of the system. The shadow prices of the power nodal balance equation provide each node LMP.

The LMPs differential will result in a merchandizing surplus [19], which can also be found as short-term transmission rent or network revenue [20]. Generally, this includes the cost of line losses and the congestion revenue. In a lossless model, the congestion revenue (TR) for a specific state is given in (2).

$$TR = \sum_{ij} f_{ij}(\mu_{\mathrm{e,i}} - \mu_{\mathrm{e,j}}) = \sum_{i} \mu_{\mathrm{e,i}}(d_i - g_i) \qquad (2)$$

where $\mu_{e,i}$ is the LMP in node i, which represents the dual variable of (1.1) of the market clearing problem, and d_i, g_i are demand and generation at each node as found in (1).

As long as transmission limits are active, congestion revenue will exist in market settlements. This congestion revenue reflects the economic value of the deficient network and it is rational to use a part or all of this revenue to network expansion investments no matter the transmission network is managed by a government owned non-profit utility or a for-profit private owned transmission company. The more congested a network is, the higher the congestion revenue gets, discouraging the transmission network owner to invest into new network lines. Therefore, the congestion level of the network must be regulated to prevent severe price risks in order to provide a competitive environment to all producers and consumers.

In [21] an effective congestion index is proposed to measure the degree of competitiveness in a power system. This can be calculated as the fraction of the mean value of all LMPs over the network minus the system clearing price without considering system transmission limits (1.3) divided by the mean value of the network LMPs. If we simulate a set of market operating scenarios, an average congestion index can be computed to quantify the overall performance of the network.

Another effective criterion proposed in [1] in order to measure price deviation due to network congestion is the standard deviation of LMPs. As the price profile becomes flatter, differences among LMP's decrease, therefore, customers purchase and sell energy at less discriminative prices and consequently competition is encouraged. On the contrary, when the price profile deviates from flatness, differences among LMP's increase, customers buy and sell at more discriminative prices, and competition is discouraged. Therefore, the flatness of price profile represented by the standard deviation of LMPs is a proper criterion for measuring the degree of competitiveness in an electric market.

B. Transmission expansion planning problem

The traditional objective of static transmission network planning is to minimize network investment cost. The deterministic TEP formulation for the proposed approach is presented in (3) for a specific time period with duration T_h.

$$\text{Max} \quad p \cdot (T_h \cdot TR) - \sum_{(i,j)} c_{ij}^{annual} n_{ij} \qquad (3)$$

Subject to

$$S^T f + g + r = d \qquad (3.1)$$

$$f_{ij} - \gamma_{ij}(n_{ij}^0 + n_{ij})(\theta_i - \theta_j) = 0 \qquad (3.2)$$

$$|f_{ij}| \le (n_{ij}^0 + n_{ij})\bar{f}_{ij} \qquad (3.3)$$

$$0 \le g \le \bar{g} \qquad (3.4)$$

$$0 \le d \le \bar{d} \qquad (3.5)$$

$$0 \le n_{ij} \le \bar{n}_{ij} \qquad (3.6)$$

$$CI \le \varepsilon_{CI} \qquad (3.7a)$$

$$STD \le \varepsilon_{std} \qquad (3.7b)$$

$$n_{ij} \text{ is integer}, (i,j) \in \Omega$$

where p is the portion of congestion revenue planned to reimburse the expansion investments as bonus, which is set by the regulator and ε_{CI}, ε_{std} are tolerance rates of the congestion index and the price deviation respectively, set by the regulator. Constraint (3.6) defines the range of the investment variables. An initial set of investment candidate circuits (right of ways) is first needed to be identified from an AC analysis. In (3), redispatching of generators is considered. Both constraints (3.7a) and (3.7b) reflect the tolerance rate in order to achieve a certain degree of price deviation, and they can be used both or separately by the regulator during the planning process to encourage competeviness over the network.

When uncertainties in generation/consumer bidding and network's configuration have to be investigated, a probabilistic approach is needed [16]. Under a Monte Carlo simulation, where the outage rate of the transmission lines and/or uncertainties in bidding behaviour are modeled, objective function (3) and constraint (3.7a)-(3.7b) are replaced by (4) and (4.1a)-(4.1b), respectively, as follows:

$$\text{Max} \quad p \cdot [T_h \cdot E(TR)] - \sum_{(i,j)} c_{ij}^{annual} n_{ij} \qquad (4)$$

$$E(CI) \ge \varepsilon_{CI} \qquad (4.1a)$$

$$STDm \ge \varepsilon_{STD} \qquad (4.1b)$$

where *E(CI)* is the expected value of the congestion index and *STDm* is the standard deviation of the mean value of the LMP resulting from the Monte Carlo simulation. These two rates can be used together or separately in the planning process in order to measure the overall grid performance.

Benders decomposition technique is used to solve this mixed integer non linear problem. The original problem is separated into two subproblems that are solved in a cycle of iterations: (i) the master problem, which is a binary integer programming problem that identifies the candidate investments and (ii) the operation subproblem, which is a linear problem with fixed integer variables that checks whether the scheme selected from the previous master problem can meet system operation constraints. If any violation occurs in the operation subproblem, a Benders cut is created, based on the linear programming duality theory, and added cumulatively in the master problem in order to solve the next iteration of the algorithm.

An analysis that considers both annual expected or total congestion revenue with multiple dispatch scenarios and different portions of this revenue planned to reimburse the expansion investments, can additionally be performed [22].

1) Operational Subproblem

In our formulation, each possible system state is represented by a distinct scenario. If a wind generator is connected to a bus, then its power output could be described by the following equation [23]:

$$P_W = \begin{cases} 0 & 0 \le V_W \le V_{CI} \\ P_R\left(V_W - V_{CI}\right)/\left(V_R - V_{CO}\right) & V_{CI} \le V_W \le V_R \\ P_R & V_R \le V_W \le V_{CO} \\ 0 & V_{CO} \le V_W \end{cases} \quad (5)$$

In this linear wind power production approximation that can be used in long term planning studies [23], the output of the wind turbine generator can be calculated if the wind speed and the wind turbines' characteristics are known. In (5), P_W is the real power output of the turbine when the wind speed is V_W *(m/s)*, V_{CI} is the cut-in and V_{CO} is the cut-out wind speed of the wind generator and P_R is the rated power of the wind turbine.

The Monte Carlo simulation technique is applied to simulate random uncertainties of system components, bidding behaviour and wind power generation [24]. The algorithm of computing the expected congestion revenue and the expected dual variables is as follows:

1) Determine the unavailability of each transmission line and assign a standard uniform probability density function (pdf).
2) Determine the pdfs for the consumer bids and the producer offers.
3) Determine the shape and scale parameters of a Weibull distribution function that can represent the wind speed at the location of the wind turbines, provided the mean value ($V_{W,MEAN}$) and the standard deviation (σ_W) of the wind speed [24].
4) Generate a number from the standard uniform pdf of each line and compare it with its unavailability. If the number is less than its unavailability then the line is on outage. Otherwise the line is working.
5) Generate a number from the pdfs of the consumer offers and the producer bids.
6) Generate a number from the Weibull distribution of the wind speed and calculate using (5) the power output of the wind turbine.
7) Run problem (1) for each scenario of the network configuration of step 4, bids of step 5 and wind power generation of step 6 and save Lagrange multipliers.
8) Calculate TR, CI and STD for each scenario
9) Repeat steps 4 to 7 for a great number of times, e.g. 10000 times.
10) Calculate the mean value of LMP over the network and STDm, the expected values of TR and CI, and finally the dual variables needed in the master problem.

Bidding behaviours, wind speed and unavailability of the transmission lines are assumed independent.

2) Investment Problem

The investment master problem is a binary integer problem, which searches the minimum cost of new added lines with constraints provided by the corresponding subproblem. The formulation of the investment problem is [25]:

$$\text{Min} \quad \sum_{(i,j)} c_{ij}^{annual} n_{ij} + \beta \quad (6)$$

Subject to

$$E(TR^k) + \sum_{i,j} E(\sigma_{\mathrm{ij}}^{\mathrm{k}})(n_{ij} - n_{ij}^k) \le \beta \quad k=1,2,\ldots,t \quad (6.1)$$

$$0 \le n_{ij} \le \bar{n}_{ij} \quad (6.2)$$

$$n_{ij} \text{ is integer}, \ (i,j) \in \Omega, \ \beta \ge 0,$$

where β is an upper bound, $E(TR^k)$ is the expected transmission revenue of the previous iteration t and $E\left(\sigma_{\mathrm{ij}}^{\mathrm{k}}\right)$ is the expected value of the sensitivity factor of objective (3) with respect to the decision variable n_{ij}. The Benders cuts are represented in (6.1), and sensitivity factor σ_{ij}^t is given by [26]:

$$\sigma_{ij}^t = \sum_{ij} \mu_{\mathrm{f,ij}} \cdot \bar{f}_{ij} \quad (7)$$

where $\mu_{\mathrm{f,ij}}$ are the dual variables (Lagrange multipliers) of constraint (1.3). When node i or node j are not connected to the system the sensitivity factor for the i-j right of way will be [27]:

$$\sigma_{ij}^t = \sum_{ij} \left|(\mu_{e,\iota} - \mu_{\mathrm{e,j}})\right| \bar{f}_{ij} \quad (8)$$

The total cost for Benders t^{th} iteration is the difference between the new added lines cost, and the expected transmission revenue computed from the t^{th} investment and operation subproblems. When the algorithm reaches a minimum total cost, the program stores the solution and continues to the next iteration. For the optimum solution, the program initiates the algorithm and solves the investment problem of the next iteration with the Benders cuts that were formulated for the minimum solution.

IV. Case Studies

The proposed algorithm was implemented in MATLAB environment and tested on the Garver 6-bus system (Fig. 1). The data of this system are shown in Tables I and II [28]. First, the static TEP problem (3) that does not take into consideration any uncertainties was investigated. Then, the probabilistic problem (4) was solved for various bidding behaviors, tolerance rates and wind characteristics. Transmission lines outages were modeled using a failure rate of 1%, the duration T_h of the specific system state was assumed 10hrs per year and the annualized cost of the lines was set at 10% of their total investment cost. It was also assumed that all the congestion revenue collected was used for the reimbursement of the expansion investments. Finally up to four circuits could be added per right of way.

TABLE I
LINE STRUCTURE OF GARVER'S TEST SYSTEM

From	To	R (pu)	X (pu)	Limit (pu)	Cost (k$)	Already built
1	2	0.10	0.40	1.00	40	1
1	3	0.09	0.38	1.00	38	0
1	4	0.15	0.60	0.80	60	1
1	5	0.05	0.20	1.00	20	1
1	6	0.17	0.68	0.70	68	0
2	3	0.05	0.20	1.00	20	1
2	4	0.10	0.40	1.00	40	1
2	5	0.08	0.31	1.00	31	0
2	6	0.08	0.30	1.00	30	0
3	4	0.15	0.59	0.85	59	0
3	5	0.05	0.20	1.00	20	1
3	6	0.12	0.48	1.00	48	0
4	5	0.16	0.63	0.75	63	0
4	6	0.08	0.30	1.00	30	0
5	6	0.15	0.61	0.78	61	0

TABLE II
GENERATOR AND DEMAND LOCATION FOR GARVER'S TEST SYSTEM

	Generators			Demands		
Node	Name	MW offer	Offer price [$/MWh]	Name	MW bid	Bid Price [$/MWh]
1	G1	150	10	D1	80	30, 28, 26, 24, 20
2	-	-	-	D2	240	34, 32, 30, 28, 25
3	G2 G3 G4	120 120 120	20 22 25	D3	40	20, 16, 14, 12, 10
4	-	-	-	D4	160	30, 27, 24, 21, 17
5	-	-	-	D5	240	34, 30, 26, 24, 18
6	G5 G6 G7 G8 G9 G10	100 100 100 100 100 100	8 12 15 17 19 21	-	-	-

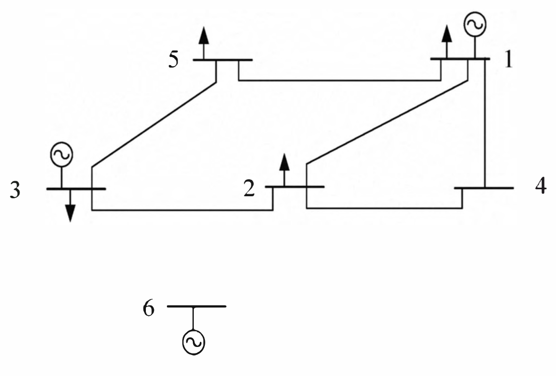

Fig.1. Initial Garver's test system

Problem (3) has been solved for various standard deviation tolerance rates while the results for this deterministic approach are given in Table III. As it is expected, the stricter the constraints are, the more the congestion cost will reduce, while the investment cost will increase. For zero congestion, the network owners' total benefit is maximized. This proves that the tolerance rates are very important for transmission expansion planning in deregulated markets and that they should be determined by the network manager based on a cost benefit analysis.

TABLE III
PLANNING SCHEMES FOR VARIOUS TOLERANCE RATES

ε_{std}	Lines Added	STD	CI	TR-Cost (k$)
3	n_{26}=2, n_{46}=1	2.964	0.1148	13214
2.5	n_{26}=2, n_{46}=1, n_{36}=1	2.50	0.1041	7629
2.2	n_{26}=2, n_{46}=2, n_{35}=1	2.147	0.0773	592
1.5	n_{26}=2, n_{46}=1, n_{36}=1, n_{15}=1	1.4966	0.0482	-2122
0.5	n_{26}=3, n_{46}=2, n_{15}=1	0.426	0.0361	-13007
0	n_{26}=4, n_{46}=1, n_{36}=1	0	0	-19800

For the probabilistic approach, it is assumed that the tolerance rate for the standard deviation of the mean of LMPs is set to 2.5 by the network planner. If we only consider the transmission outage failure rates, then the solution obtained for the optimal network expansion is 2 new lines between nodes 2 and 6 (n_{26}=2), 1 new line between nodes 4 and 6 (n_{46}=1) and 1 new line connecting nodes 3 and 5 (n_{35}=1). The standard deviation of the mean of LMPs is 2.487 while the probability of exceeding the tolerance rate is found 0.047. The expected congestion index is 0.0861 while the total expected transmission revenue is 6847$.

It is now assumed that instead of generator G2, a wind farm with the same capacity is connected to node 3. The generation output of the wind farm follows (5), with parameters set at: V_R=11.9m/s, V_{CI}=3.5m/s and V_{CO}=25m/s. The results for various wind speed characteristics are provided in Table IV. The algorithm is terminated when the probability of the standard deviation exceeding the tolerance rate is below 0.05.

Finally, normal distribution is considered for the pdfs of the consumers bids and the producers offers, while the wind characteristics are $V_{W,MEAN}$=7m/s and σ_W=2,5m/s. Table V provides the results for different standard deviation levels of the offers/bids.

TABLE IV
PLANNING SCHEMES FOR DIFFERENT WIND CHARACTERISTICS

Wind speed characteristics	Lines added	E(TR)-Cost (k$)	STDm	Pr{STD>ε_{STD}}
$V_{W,MEAN}$=5.5m/s, σ_W=2m/s	n_{26}=3, n_{46}=1, n_{15}=1	0.719	2.139	0.032
$V_{W,MEAN}$=7m/s, σ_W=2.5m/s	n_{26}=3, n_{46}=1, n_{15}=1	-1.764	2.167	0.035
$V_{W,MEAN}$=10m/s, σ_W=3.5m/s	n_{26}=2, n_{46}=2, n_{35}=1, n_{23}=1	- 3.404	2.397	0.048

TABLE V
PLANNING SCHEMES FOR VARIOUS OFFERS/BIDS STANDARD DEVIATION

Standard deviaton of offers/bids	Lines added	E(TR)-Cost (k$)	STDm	Pr{STD > ε_{STD}}
10%	n_{26}=3, n_{46}=1, n_{15}=1	-1.422	2.212	0.027
20%	n_{26}=3, n_{46}=1, n_{15}=1	-1.501	2.152	0.036
30%	n_{26}=3, n_{46}=1, n_{35}=1	-2.115	1.408	0.049

V. CONCLUSION

This paper proposes a model for transmission expansion planning in deregulated electricity markets, considering transmission congestion, wind power integration and double-sided bidding power-pool operation for both generation and demand. If there is congestion in the network, the market clearing process will always result in a congestion revenue. The transmission owner has no incentive to invest on the reimbursement of the grid unless this revenue is somehow regulated. In this paper two rates were introduced for the evaluation of the network's competitiveness. This revenue must be used for transmission reinforcements.

A multiyear transmission planning is needed in order to decide the optimal capacity and location of the new infrastructure taking into consideration load and generation estimated growth. A representation of typical dispatch scenarios with their relevant duration is also needed to calculate the estimated annual congestion revenue. The example that was provided in this paper used only one dispatch snapshot, although more than one could easily be used.

Wind power increases the uncertainty in future generation. However, wind generator contribution should not be neglected from the transmission planning procedure. A probabilistic approach that will take into consideration the correlation between the wind farms along the grid should be performed for various wind "flow" scenarios. A good approximation for long run planning can be provided with the aforementioned equation for the generation output. However, in the transmission revenue gain or loss that might appear for a future network scheme, the wind farm's remuneration for wind power enforced curtailment should also be taken into account. This is left to a future work. It is not clear whether wind power alleviates or worsens congestion in the network. It depends on the location and of course on the network configuration and dispatch resulting from the offers/bids of the generators/loads.

Different topologies result for different tolerance price deviation rates. The exact value of the congestion index must be selected after careful examination of previous and future network bevaviours. Network reinforcements depend on the market clearing results. Different generator and load dispatches can result in very different planning schemes. However, the system operator can estimate producers' and consumers' behaviour with limited uncertainty in order to be able to provide with his decisions a competitive environment to all producers and consumers.

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