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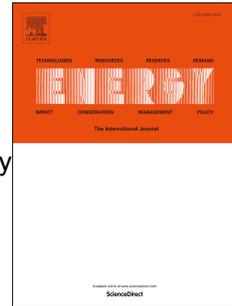
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Risk Assessment of Power Transmission Network Failures in a Uniform Pricing Electricity Market Environment

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Abstract

This paper proposes a novel risk assessment method for power network failures considering a uniform-pricing market environment, different from previous risk assessment studies, which mainly emphasize technical consequences of the failures. In this type of market, dispatch infeasibilities caused by line failures are solved using a counter-trading mechanism where costs arise as a result of correcting the power dispatch. The risk index proposed takes into account these correction costs as well as the cost of the energy not served due to the failure, while considering an oligopolistic behavior of the generation companies. A 3-stage model is proposed to simulate the bidding behavior in the market, under different line failures scenarios. The risk index proposed and the method for its calculation are applied on an adapted IEEE 6-bus

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reliability test system. A sensitivity analysis is performed to investigate the sensitivity of the results with respect to the level of competitiveness of the generation companies, measured by the conjectured-price response parameter which is assumed to be exogenous in our study.

Keywords:

Risk assessment, Transmission network, Electricity market, Line failure, Conjectural-variation equilibrium, Direct-current optimal power flow.

List of symbols

Indices:

- a network bus index
- i generation companies (GenCos) index
- j generation unit index
- k generation unit index (alias for j)
- l transmission line index

Sets:

- N set of indices of network buses
- I set of indices of generation companies (GenCos)
- J set of indices of generation units
- J_a set of indices of generation units located on bus a
- J_i set of indices of generation units belonging to GenCo i
- L set of indices of the transmission lines in the system
- Π set of optimization variables in the DAM problem
- Δ set of optimization variables in the BM problem
- Ξ set of optimization variables in the DC-OPF problem

Constants:

| | |
|---------------|--|
| c_j | production cost of unit j (€) |
| \bar{q}_j | maximum production capacity of unit j (MW) |
| θ_i | conjectured-price response of company i in the day-ahead market [(€/MWh)/MW] |
| β_i | conjectured-price response of company i in the upwards balancing market [(€/MWh)/MW] |
| ϕ_i | conjectured-price response of company i in the downwards balancing market [(€/MWh)/MW] |
| D | total active power demand in the system (MW) |
| D_a | total active power demand per network bus a (MW) |
| MC_j | marginal cost of unit j (€/ MWh) |
| $cens_a$ | cost of energy not served at network bus a (€/ MWh) |
| $ms_{(a,a')}$ | mechanical state of transmission line connecting bus a and a' |
| $B_{(a,a')}$ | transmission line susceptance (p.u.) |
| OR_l | transmission line outage rate per year |
| T_l | transmission line average outage duration (hr) |
| Hrs | transmission line total number of operating hours per year (hr) |

Variables:

| | |
|--------------|--|
| λ_i | day-ahead market price estimation by GenCo i (€/ MWh) |
| γ_i | upwards balancing market price estimation by GenCo i (€/ MWh) |
| ψ_i | downwards balancing market price estimation by GenCo i (€/ MWh) |
| λ^* | day-ahead market equilibrium price (€/ MWh) |
| γ^* | upwards balancing market equilibrium price (€/ MWh) |
| ψ^* | downwards balancing market equilibrium price (€/ MWh) |
| q_j^{DAM} | non-equilibrium solution for the active power quantity bid of unit j (MW) in the day-ahead market |
| q_j^{*DAM} | equilibrium solution for the active power quantity bid of unit j in the day-ahead market (MW) |
| x_j^{BM} | non-equilibrium solution for the upwards power quantity bid of unit j in the balancing market (MW) |
| x_j^{*BM} | equilibrium solution for the upwards power quantity bid of unit j in the balancing market(MW) |
| z_j^{BM} | non-equilibrium solution for the downwards power quantity bid of unit j in the balancing market (MW) |
| z_j^{*BM} | equilibrium solution for the downwards power quantity bid of unit j in the balancing market (MW) |

| | |
|------------------|---|
| $\bar{\mu}_j$ | dual variable |
| $\bar{\nu}_j$ | dual variable |
| $\bar{\xi}_j$ | dual variable |
| $\bar{\delta}_j$ | dual variable |
| u_j^{OPF} | binary variable equals to 1 if unit j is required to participate in the upwards balancing market and 0 otherwise |
| u_a^{OPF} | binary variable equals to 1 if any unit on bus a is required to participate in the upwards balancing market and 0 otherwise |
| w_j^{OPF} | binary variable equals to 1 if unit j is required to participate in the downwards balancing market and 0 otherwise |
| w_a^{OPF} | binary variable equals to 1 if any unit on bus a is required to participate in the downwards balancing market and 0 otherwise |
| x_a^{vg} | amount of energy not served at network bus a (MWh) |
| q_j^{OPF} | feasible active production for unit j as found in the optimal power flow problem (MW) |
| $F_{(a,a')}$ | power flow in the network line connecting bus a and a' |
| δ_a | voltage angle at network bus a |

Acronyms:

| | |
|--------|-------------------------------------|
| BM | Balancing Market |
| DAM | Day-Ahead Market |
| DB | Downwards Balancing |
| DC-OPF | Direct-Current - Optimal Power Flow |
| ELIC | Expected Load Interruption Cost |
| ELNS | Expected Load Not Supplied |
| ENS | Energy Not Served |
| KKT | Karush-Kuhn-Tucker |
| MCP | Mixed Complementarity Problem |
| M.O. | Market Operator |
| S.O. | System Operator |
| UB | Upwards Balancing |
| VG | Virtual Generator |

1 **1. Introduction**

2 Safety and reliability have always been critical for power systems [1]. A
 3 number of studies have been dedicated to propose different criteria [2], as-
 4 sessment methods [3], metrics, and standards [4]. More recently, the focus
 5 has been on studying power systems reliability considering distributed gen-
 6 eration [5], the integration of renewable energy sources [6] especially wind [7]
 7 and photovoltaic [8], the impact of severe weather conditions [9], and the im-
 8 pact of energy storage [10] and electric vehicles integration [11]. In addition,
 9 reliability studies have considered the contribution of demand response pro-
 10 gram [12], smart-grid developments [13] and cyber-security [14]. Moreover,

11 the deregulation of the power systems and the introduction of different mar-
12 ket designs have motivated studies of system reliable operation considering
13 different market interactions, such as the uncertainties of renewable power
14 generation [15], the consideration of micro-grids [16], and especially ensuring
15 markets adequately operating for energy reserves [17].

16 However, reliability assessments may not tell the full story when consid-
17 ering the actual impact of a failure in the system, as that effect is typically
18 evaluated in terms of probability and severity (consequence), within a risk
19 assessment framework [18]. A power system consists of many components
20 (e.g. generators, transmission and distribution lines, transformers, breakers,
21 switches, communication devices, etc.) which are prone to failures. Since
22 most of these components can be -either directly or indirectly- attributed to
23 the transmission and distribution networks, the available literature has been
24 notably focusing on quantifying the impacts of failures in these networks.

25 A network contingency can be considered to result in one or both of the
26 following effects on the system: the isolation of a demand/generation bus
27 from the rest of the system leading to an amount of energy not served (ENS),
28 and/or the congestion of one or several other lines in the network due to the
29 updated network topology and the limited capacity for each line, leading
30 to the need of re-dispatching the generated power to ensure the technical
31 stability of the network and to minimize any unsatisfied demand. If a line
32 failure produces neither of these effects, then the line can be considered
33 redundant and its failure has no influence on the operation of the system.

34 In literature, the severity of network failures has regarded technical im-
35 pacts such as circuit flow limits and voltage level violation, duration and fre-

36 quency of interruption, amount of energy not supplied (ENS) and expected
37 load not supplied (ELNS), and economic impacts such as the expected load
38 interruption cost (ELIC), and ENS cost.

39 Reference [19] presents a probabilistic risk assessment of distributed gen-
40 eration (DG) systems, considering extreme weather conditions. They con-
41 sider the probability of a distribution line contingency and its consequence
42 as the extent of voltage level violation. Reference [20] also proposes a risk
43 assessment method for power systems in extreme weather conditions with
44 the amount of load curtailed as a severity function. Reference [21] analyzes
45 a distribution network with DG, considering the risk of protection system
46 miss-coordination, under three severity functions: interruption frequency,
47 interruption duration and amount of ENS. A probabilistic risk assessment
48 of transmission network contingencies is proposed in: [22] as the extent of
49 thermal rating violation, [23] within a risk-based multi-objective optimiza-
50 tion that accounts for overload risk, low voltage risk, and cost, [24] in terms
51 of voltage level violation for a near-future condition, and in [25] in terms
52 of line overload for wind-integrated power systems. Reference [26] considers
53 the risk of transmission network deliberate outage within a network expan-
54 sion planning framework, in terms of the amount of load shed. References
55 [27] propose a method to evaluate the risk of transmission network failure in
56 terms of load not supplied, while considering the operator responding to the
57 failure by re-dispatching the power to avoid a system blackout and minimize
58 the amount of load-shed. Reference [28] evaluates the security of a wind
59 integrated power system using a risk index assessing the outage of a single
60 and/or a double circuit of a line, and its economic consequence in terms of

61 ELIC. Study [29] proposes a risk assessment for the combined transmission
62 and distribution networks within a hierarchical framework, with four severity
63 functions namely: expected energy not supplied (EENS), probability of load
64 curtailment (PLC), expected frequency of load curtailment (EFLC) and
65 the equivalent duration of one complete system outage during peak condi-
66 tions. Finally, the work [30] implements a risk analysis within a planning
67 framework for the distribution network which accounts for the consequence
68 of overcurrents and voltage violations in monetary terms. All of these stud-
69 ies, however, have considered a system with centralized power dispatch. A
70 power market context has been considered in the risk evaluation proposed
71 by [31], where the merit order power dispatch is selected based on sampled
72 bidding prices and the network failure severity is measured in terms of ENS
73 cost.

74 On the contrary to our knowledge, none of the existing works have eval-
75 uated the system risk considering the economic cost of correcting the power
76 dispatch due to the network contingency, within a market context. In fact,
77 some studies have argued that the use of economic indexes for risk assessment
78 such as the cost of interruption or the re-dispatching cost is not suitable, as
79 it presupposes the decision itself that the index is ought to facilitate [24],
80 or because it introduces uncertainties beyond those reflected by performance
81 measures, that are difficult to model accurately [22]. The first argument,
82 however, gives exception to cases where load interruptions are inevitable and
83 are, therefore, not the result of an operator decision [24], which is, indeed,
84 the case for many of the network failures scenarios. Moreover, we argue that
85 in a market context where the electricity supplied and demanded are traded

86 and are subject to various price signals, it is important to analyze the global
87 economic severity of the different contingencies.

88 In this work, we propose a risk assessment method which considers the
89 economic severity of network failures in terms of both the cost of ENS and the
90 cost of correcting the dispatch in the network, in a market context. We con-
91 sider a uniform pricing market with a counter-trading mechanism for clearing
92 network infeasibilities in case of line failures and oligopolistic generation com-
93 panies (GenCos) that are able to act strategically and exercise market power.
94 The uniform-pricing market, the zonal market, and the nodal pricing market
95 are the three market schemes dominantly adopted in deregulated systems
96 [32]. However, when it comes to the need of congestion management which
97 could arise due to a network contingency, the nodal pricing schemes internal-
98 ize the congestion costs in the energy prices at each node [33], and therefore
99 no subsequent mechanism or pricing is needed to manage this congestion.
100 This is not the case for a uniform-pricing market, or within each zone in the
101 zonal market, which are the market schemes implemented in most western
102 European countries. Several works have studied the effects of network conges-
103 tion on the performance of a uniform-pricing electricity market and especially
104 in terms of strategic bidding and exercise of market power. Most notably,
105 reference [33] compares nodal pricing and counter-trading mechanisms for
106 managing network congestion in electricity markets. In doing so, they study
107 the effect of counter-trading on the generation companies strategic bidding
108 in the day-ahead market (DAM) and on overall social welfare, by evaluating
109 the potential benefits of introducing additional competition. They show that
110 under counter-trading, the new entrant in the export constrained area can

111 collect additional profits, resulting in over-investment in this area, and in a
112 welfare loss for the society. Reference [34] analyzes the congestion influence
113 on GenCos bidding strategies by providing an analytical framework for solv-
114 ing a mixed-strategy Nash equilibrium, representing the GenCos interaction
115 in a uniform-pricing market. They show that congestion in the transmission
116 network may increase the GenCos ability to exercise market power, result-
117 ing in higher prices. Both approaches, however, are only aimed at providing
118 insights on the above-mentioned effects and therefore have limited applica-
119 bility to large size problems. Study [35] address the same issue by proposing
120 a conjectural-variation equilibrium problem to model the GenCos strategic
121 interaction in the uniform-pricing market. The equilibrium problem is cast
122 as an equivalent quadratic minimization that can be readily solved with com-
123 mercial solvers. The framework proposed includes a Direct-Current Optimal
124 Power Flow (DC-OPF) model to solve the network power dispatch. A simi-
125 lar framework to study the effect of network congestion on GenCos strategic
126 bidding is proposed in [36]; however, the network congestion is considered as
127 the level of voltage level violation, instead of active power flow violation, and
128 an AC-OPF model is implemented, instead of the DC-OPF.

129 All of the above studies internalize the effect of counter-trading on the
130 GenCos strategic bidding in the DAM. Namely, they consider that since net-
131 work congestions are a recurring phenomenon, GenCos can anticipate its
132 effect, and internalize it by optimizing their bids both in the DAM and the
133 subsequent counter-trading mechanism, simultaneously. While this is suit-
134 able for the purpose of their studies, we defer in that we consider an explicit
135 separation between the GenCos bidding in the DAM and that of the subse-

136 quent correction mechanism, which we refer to as the balancing market (BM).
137 This is because we consider congestion situations which arise exclusively due
138 to network contingencies, that occur unexpectedly, and less often during nor-
139 mal power system operation, and therefore it is highly unlikely that GenCos
140 would change their strategies in the DAM to take them into account. Gen-
141 Cos can still, however, react to such contingencies by adapting their offers
142 in the BM, in order to maximize their profits. This explicit separation also
143 helps emphasizing the cost of the dispatch correction arising due to the net-
144 work contingency, especially for risk assessment and comparison purposes.
145 Moreover, since anticipating and internalizing network congestions in the
146 DAM offering would constitute solving a model represented as an Equilib-
147 rium Problem with Equilibrium Constraint (EPEC) [37], that is non-linear
148 and non-convex, iterative solution methods such as that presented in [35] are
149 necessary to solve it, and it is often very difficult to achieve convergence and
150 to validate the solutions obtained.

151 For the risk assessment, we propose a 3-stage model to simulate the dereg-
152 ulated power system behavior in case of a network failure, consisting of a
153 conjectural-variation equilibrium model simulating the GenCos competition
154 in the day-ahead uniform pricing market (DAM), a direct-current optimal
155 power flow model (DC-OPF) to obtain the feasible dispatch in the network,
156 and a conjectural-variation equilibrium model to simulate the counter-trading
157 mechanism. We finally propose a risk index to quantify the economic impact
158 of the different line failures. The method is tested on a 6-bus system adapted
159 from the IEEE 6-bus Reliability Test System [38], and the results are pre-
160 sented and discussed.

161 The rest of the paper is organized as follows. Section 2 describes in details
162 the uniform-pricing market scheme under study and illustrates the model as-
163 sumptions and formulation. Section 3 illustrates the solution method adopted
164 to solve the 3-stage model. Section 4 describes in details the numerical ex-
165 ample used in this study. Section 5 presents and explains the risk assessment
166 results. Section 6 provides a sensitivity analysis for the risk index proposed
167 with respect to the level of competitiveness assumed for the different GenCos
168 and Section 7 concludes the work.

169 **2. Model assumption and formulation**

170 In electricity markets, competing GenCos who wish to produce have to
171 participate in the day ahead market (DAM), by offering to the market opera-
172 tor (M.O.) hourly bids that consist of quantities and price pairs for next day
173 production schedule. The M.O. aggregates all the supply bids, and collects
174 and aggregates all the demand bids to construct the supply-demand curve.
175 The M.O. re-arranges all the bids received from the suppliers in an ascend-
176 ing order in terms of prices (each generation unit considered separately) and
177 each bid received from the demand in a descending order, until the total
178 generation equals the total demand. Thus, the market marginal price is set
179 to the bid price of the most expensive unit committed for dispatch. In a
180 uniform pricing market, this price will be the same used for the remuner-
181 ation of all the units committed. If we do not take into consideration the
182 network representation, it is very probable that the schedule resulting from
183 the market clearing may not be technically feasible (e.g. may exceed the
184 maximum capacities of the lines). Moreover, in the case of a line failure, the

185 system operator (S.O.) will need to re-dispatch the units to ensure an energy
186 dispatch in the network that minimizes the amount of energy not served (in
187 case curtailment is inevitable), and to ensure the system stability so that
188 no other line becomes overloaded, with the risk of leading to a cascading
189 network failure.

190 In a uniform pricing market, the re-dispatching strategy is typically im-
191 plemented via a counter-trading mechanism, which can be approximated as
192 follows [33]: the S.O. receives price-quantity bids for the day-ahead mar-
193 ket from the GenCos and price-quantity bids for the subsequent balancing
194 market, representing the price at which each GenCo is willing to increase or
195 reduce, in terms of production of each unit with respect to the result of the
196 DAM schedule, in case there is a need for a re-dispatch. The S.O. would solve
197 an OPF problem prior to real-time dispatch, based on the schedule proposed
198 in the DAM, to check the schedule feasibility. Typically, this analysis would
199 have as primary aim the identification and elimination of network congestion.

200 For those units that will have to increase their production, the trans-
201 mission adjustments can be paid at the equilibrium price of the production
202 increase bids in the upwards BM. While for the units which are required to
203 decrease their production, they would ideally bid according to their “avoided
204 fuel costs” in the downwards BM, and would be either charged the equi-
205 librium price of this market, or a price in accordance to a pay-as-bid rule
206 [33].

207 We propose to model this market mechanism through a 3-stage model:
208 the first stage is an equilibrium problem to obtain the DAM price and sched-
209 ule, the second stage is a DC-OPF power flow problem, which represents

210 the S.O. decisions, and the third stage is an equilibrium problem to find
 211 the competition outcome in both the upwards and the downwards BM and,
 212 subsequently, calculate the correction costs. Both equilibrium models for
 213 the DAM and BM are formulated as a conjectural-variation problem that
 214 allows the parametrization of different levels of competition among the Gen-
 215 Cos through the conjecture price-response parameters [39], considered to be
 216 exogenously obtained in the problem. This formulation is similar to that
 217 proposed in [36].

218 *Competition in the Day-Ahead Market*

Under the simplest assumptions, in the DAM competition each firm i is searching to maximize its profit following:

$$\max_{\Pi} \lambda_i \cdot \sum_{j \in J_i} q_j^{DAM} - \sum_{j \in J_i} c_j(q_j^{DAM}) \quad (1)$$

Subject to:

$$\lambda_i = \lambda^* - \theta_i \cdot \left(\sum_{j \in J_i} q_j^{DAM} - \sum_{j \in J_i} q_j^{*DAM} \right) \quad (2)$$

$$\bar{q}_j - q_j^{DAM} \geq 0 : \quad (\bar{\mu}_j) \quad \forall j \in J \quad (3)$$

$$q_j^{DAM} \geq 0 \quad \forall j \in J \quad (4)$$

219 where $\Pi = \{\lambda_i, q_j^{DAM}\}$. The objective function (1) is the profit function to
 220 be maximized and it is equal to the revenues obtained from the production in
 221 the DAM $\left(\lambda_i \cdot \sum_{j \in J_i} q_j^{DAM} \right)$ minus the costs of production $\left(\sum_{j \in J_i} c_j(q_j^{DAM}) \right)$.
 222 The price (λ_i) represents GenCo (i) estimation of the DAM price. Since
 223 we assume that the participating GenCos are price makers, their production
 224 decisions should endogenously determine the market price. This strategic

225 behavior is represented with constraint (2) by means of the conjecture-price
 226 response parameter ($\theta_i = -\partial\lambda_i/\partial q_j^{DAM}$). In equilibrium, the single DAM
 227 equilibrium price is (λ^*) and the optimal quantity produced is (q_j^{*DAM}). Con-
 228 straint (2) ensures that both upwards and downwards deviations in the pro-
 229 duction from the optimal production levels reduce the company profits, thus
 230 ensuring that the price estimate (λ_i) is equal to the equilibrium price (λ^*).
 231 Constraints (3) and (4) are the boundaries of the production variables.

232 *Competition in the Balancing Market*

233 In case of schedule infeasibilities due to network constraints, generation
 234 units will have to be re-dispatched. Some units will have to increase, while
 235 others will have to reduce their productions. In a market context, this re-
 236 scheduling will be achieved by referring to the bids in both the upwards
 237 and the downwards BM. It is, therefore, very likely that competing GenCos
 238 will choose their bids strategically to maximize their profits as well in this
 239 subsequent mechanism. We can approximate the GenCos strategic behavior
 240 in the BM by solving an optimization problem where each GenCo seeks to
 241 maximize its profit. The BM optimization problem for each firm (i) can be
 242 formulated as:

$$\max_{\Delta} \gamma_i \cdot \sum_{j \in J_i} x_j^{BM} - (\psi_i + \lambda^*) \cdot \sum_{j \in J_i} z_j^{BM} - \sum_{j \in J_i} c_j (x_j^{BM} - z_j^{BM}) \quad (5)$$

Subject to:

$$\gamma_i = \gamma^* - \beta_i \cdot \left(\sum_{j \in J_i} x_j^{BM} - \sum_{j \in J_i} x_j^{*BM} \right) \quad (6)$$

$$\psi_i = \psi^* - \phi_i \cdot \left(\sum_{j \in J_i} z_j^{BM} - \sum_{j \in J_i} z_j^{*BM} \right) \quad (7)$$

$$\bar{q}_j \cdot u_j^{OPF} - x_j^{BM} \geq 0 : (\bar{v}_j) \quad \forall j \in J \quad (8)$$

$$\bar{q}_j - q_j^{DAM} - x_j^{BM} \geq 0 : (\bar{\xi}_j) \quad \forall j \in J \quad (9)$$

$$q_j^{DAM} \cdot w_j^{OPF} - z_j^{BM} \geq 0 : (\bar{\delta}_j) \quad \forall j \in J \quad (10)$$

$$x_j^{BM} \geq 0, \quad z_j^{BM} \geq 0 \quad \forall j \in J \quad (11)$$

$$\{q_j^{DAM}\} \in \arg \Pi \quad (12)$$

$$\{u_j^{OPF}, w_j^{OPF}\} \in \arg \Xi \quad (13)$$

243 where $\Delta = \{\gamma_i, \psi_i, x_j^{BM}, z_j^{BM}\}$. The objective function (5) represents the
 244 profit function for each GenCo (i). (x_j^{BM}) and (z_j^{BM}) are the decision vari-
 245 ables for the upwards and the downwards production quantities, respectively,
 246 while (γ_i) and (ψ_i) are the market prices for the upwards and the downwards
 247 BM respectively. It is important to note that the revenues from the down-
 248 wards balancing market ($\psi_i \cdot \sum_{j \in J_i} z_j^{BM}$) are represented as a negative term
 249 in the profit function, this is to portray that competing firms will perceive
 250 them as a charge, and calculate their bids in accordance to their avoided fuel
 251 cost resulting from the reduced real time production. Moreover, the loss of
 252 profit from not producing in the DAM is illustrated by subtracting the term
 253 ($\lambda^* \cdot \sum_{j \in J_i} z_j^{BM}$), where at this stage the DAM price (λ) is known. Constraints
 254 (6) and (7) ensure that the optimization output is equal to the equilibrium
 255 output of the market, and follow the same explanation given for constraint
 256 (2). The conjecture price-responses for the upwards BM and the downwards
 257 BM are ($\beta_i = -\partial\gamma_i/\partial x_j^{BM}$) and ($\phi_i = \partial\psi_i/\partial z_j^{BM}$), respectively.

258

259 Constraints (8)-(11) are the boundaries for the decision variables. (u_j^{OPF})
 260 and (w_j^{OPF}) are binary decision variables from the DC-OPF problem, they
 261 represent the state of the units which will be able to increase or decrease
 262 their productions respectively, in order to correct the real time dispatch. If
 263 (u_j^{OPF}) or (w_j^{OPF}) is equal to 1, it means that the respective unit (j) can
 264 participate in the upwards or in the downwards BM, respectively; other-
 265 wise, it can not. This is to ensure a simplified, yet realistic, representation
 266 of the market, where no unit can participate in the BM unless it is physi-
 267 cally located on a network bus where the BM is activated in order to solve
 268 the congestion. Finally, equations (12) and (13) indicate that the variables
 269 $\{q_j^{DAM}\}$ and $\{u_j^{OPF}, w_j^{OPF}\}$ are the output of the decision variables in the
 270 DAM market problem and the DC-OPF problem, respectively.

271 *Market Clearing Conditions*

Since we seek to find the equilibrium market outcome, we need to define the market clearing equations. These equations are the governing conditions that link the individual GenCos optimization problems together. For a uniform-pricing DAM, the total energy production has to be equal to the total demand, or:

$$\sum_{j \in J} q_j^{DAM} = D \quad \forall j \in J \quad (14)$$

Similarly, for the BM, the sum of the increased or reduced production is equal to the sum of the energy required for the upwards-balancing (UB) or the downwards-balancing (DB), respectively, or:

$$\sum_{j \in J} x_j^{BM} = UB \quad \forall j \in J \quad (15)$$

$$\sum_{j \in J} z_j^{BM} = DB \quad \forall j \in J \quad (16)$$

272 *Equilibrium problem formulation*

273 For the DAM problem, the corresponding MCP is defined by finding the
274 system of equations which corresponds to the Karush-Kuhn-Tucker (KKT)
275 conditions of the problem (1) to (4), after substituting for (λ_i) by the right-
276 hand side of constraint (2) and adding the market clearing condition (14).

The DAM-MCP is, thus, defined as:

$$0 \leq q_j^{*DAM} \perp -\lambda^* + \theta_i \cdot \sum_{j \in J_i} q_j^{*DAM} + MC_j(q_j^{*DAM}) + \bar{\mu}_j \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (17)$$

$$0 \leq \bar{\mu}_j \perp \bar{q}_j - q_j^{*DAM} \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (18)$$

$$\sum_{j \in J} q_j^{DAM} = D \quad : \quad \lambda \quad (19)$$

277 where the DAM price (λ) is obtained as the dual-variable of the market clear-
278 ing constraint (19). All other constraints are solved for all units (j) belonging
279 to GenCo (i) , and for all GenCos.

280

Similarly, we define the BM-MCP as:

$$0 \leq x_j^{*BM} \perp -\gamma^* + \beta_i \cdot \sum_{j \in J_i} x_j^{*BM} + MC_j(x_j^{*BM} - z_j^{*BM}) + \bar{\nu}_j + \bar{\xi}_j \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (20)$$

$$0 \leq z_j^{*BM} \perp \psi^* + \lambda^* + \phi_i \cdot \sum_{j \in J_i} z_j^{*BM} - MC_j(x_j^{*BM} - z_j^{*BM}) + \bar{\delta}_j \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (21)$$

$$0 \leq \bar{\nu}_j \perp \bar{q}_j \cdot u_j^{OPF} - x_j^{*BM} \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (22)$$

$$0 \leq \bar{\xi}_j \perp \bar{q}_j - q_j^{*DAM} - x_j^{*BM} \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (23)$$

$$0 \leq \bar{\delta}_j \perp q_j^{*DAM} \cdot w_j^{OPF} - z_j^{*BM} \geq 0, \quad \forall j \in J_i, \forall i \in I \quad (24)$$

$$\sum_{j \in J} x_j^{BM} = UB \quad : \quad \gamma \quad (25)$$

$$\sum_{j \in J} z_j^{BM} = DB \quad : \quad \psi \quad (26)$$

281 where equations (20) to (24) correspond to the KKT conditions of the prob-
 282 lem (5)–(13), and equations (25) and (26) are the market clearing conditions
 283 as previously described. The market prices (γ) and (ψ) are obtained as the
 284 dual-variables of the market clearing conditions of the upwards BM (25), and
 285 that of the downwards BM (26), respectively.

286 *Direct-Current (DC) Optimal Power Flow Model*

287 The network's operating decisions by the S.O. taking into account the
 288 technical representation of the electricity network is modeled through a DC-
 289 OPF problem. This problem is formulated as a mixed-integer linear pro-
 290 gramming problem as follows:

$$\min_{\Xi} \sum_{a \in N} cens_a \cdot x_a^{vg} \quad (27)$$

subject to:

$$\sum_{j \in J_a} q_j^{OPF} + \sum_{a' \in N} F_{(a,a')} = D_a - x_a^{vg}, \quad \forall a \in N, \quad \forall (a, a') \in L \quad (28)$$

$$F_{(a,a')} = ms_{(a,a')} B_{(a,a')} (\delta_a - \delta_{a'}), \quad \forall (a, a') \in L \quad (29)$$

$$\sum_{j \in J_a} q_j^{OPF} = \sum_{j \in J_a} q_j^{DAM} + \sum_{j \in J_a} x_j^{OPF} - \sum_{j \in J_a} z_j^{OPF}, \quad \forall j \in J_a, \quad \forall a \in N \quad (30)$$

$$0 \leq \sum_{j \in J_a} q_j^{OPF} \leq \sum_{j \in J_a} \bar{q}_j, \quad \forall j \in J_a, \quad \forall a \in N \quad (31)$$

$$0 \leq \sum_{j \in J_a} x_j^{OPF} \leq \sum_{j \in J_a} \bar{q}_j \cdot u_a^{OPF}, \quad \forall j \in J_a, \quad \forall a \in N \quad (32)$$

$$0 \leq \sum_{j \in J_a} z_j^{OPF} \leq \sum_{j \in J_a} \bar{q}_j \cdot w_a^{OPF} \cdot (1 - u_a^{OPF}), \quad \forall j \in J_a, \quad \forall a \in N \quad (33)$$

$$0 \leq x_a^{vg} \leq D_a, \quad \forall a \in N \quad (34)$$

$$\delta_1 = 0 \quad (35)$$

$$u_a^{OPF}, w_a^{OPF} \in \{0, 1\}, \quad \forall j \in J \quad (36)$$

291 where $\Xi = \{q_j^{OPF}, x_j^{OPF}, z_j^{OPF}, x_a^{vg}, F_{(a,a')}, \delta_a, \delta_{a'}, u_a^{OPF}, w_a^{OPF}\}$. The
 292 objective function (27) of the S.O. is to minimize the energy not served
 293 in the network, given the DAM schedule, subject to the network technical
 294 constraints. (x_a^{vg}) is the amount of energy not served at each network bus (a),
 295 which is obtained as the production value of a virtual-generator (vg) added
 296 to this network bus. ($cens_a$) is the cost of energy not served at bus (a) and
 297 is represented as the cost of production of the respective (vg). (q_j^{OPF}) is the
 298 final production output as found in the DC-OPF and $\left(\sum_{j \in J_a} x_j^{OPF}, \sum_{j \in J_a} z_j^{OPF}\right)$
 299 are the total upwards and downwards amounts of energy required per network
 300 bus a . Constraint (28) is the supply-demand balance equation considering
 301 the power flows in the network ($F_{(a,a')}$), which are either entering (positive)
 302 or leaving (negative) bus (a). Constraint (29) defines the active power flow
 303 in the different lines of the network, where ($B_{(a,a')}$) is the line susceptance
 304 and (δ_a) is the voltage-angle at each bus. The mechanical state of each
 305 line ($ms_{(a,a')}$) is an exogenous parameter: it takes the value of 1 if the line
 306 is active and the value of 0 if the line fails, and it is how the line failure

307 status is represented in the dispatch problem. Constraint (30) ensures the
 308 consistency between the decisions taken in the final production schedule and
 309 the DAM bidding schedule. Constraints (31) to (34) are the boundaries of the
 310 decision variables, namely the production quantity (q_j^{OPF}), the upwards and
 311 the downwards production required (x_j^{OPF}) and (z_j^{OPF}), respectively. (u_a^{OPF})
 312 is a binary decision variable, which is equal to 1 if the units at bus (a) are
 313 required to increase their production to solve a network constraint and is
 314 equal to 0 otherwise. Similarly, (w_a^{OPF}) is a binary decision variables, which
 315 is equal to 1 if the units at bus (a) are required to reduce their production
 316 and 0 otherwise. The term ($1 - u_a^{OPF}$) in constraint (33) ensures that units
 317 on the same bus can not be required to increase and reduce their productions
 318 at the same time. Finally, constraint (35) sets the bus voltage-angle reference
 319 point at bus (1).

320 *Risk Index and Assessment Method*

To adopt a quantitative definition of risk, we refer to expected consequence as the product of the probability of occurrence of an undesired event (e.g. transmission line failure) and the resulting consequence [18]. To take into account the negative effect of several undesired events, the definition is extended by summing all relevant consequence contributions. Formally, we can express the risk as:

$$Risk(R) = \sum_n p(E_n) \cdot Sev(E_n) \quad (37)$$

321 where n is the event index, $p(E_n)$ is the probability of occurrence of the
 322 undesired event E_n and $Sev(E_n)$ is the severity of the related consequences.

323 *Probability Model*

324 We adhere to the intrinsic failure characteristics of the transmission lines
 325 to calculate the probability of line failure, extrapolating the historical data of
 326 the permanent outage rate for each line and its respective outage duration in
 327 hours. However, different contributions can be considered, for example that
 328 of a line failure due to voltage instability caused by a stochastic renewable
 329 production source [28] or the probability of failure resulting from extreme
 330 weather conditions [19].

The probability model for the risk assessment is, thus, defined as:

$$p(E_l) = \frac{OR_l \cdot T_l}{Hrs}, \quad \forall l \quad (38)$$

331 where l is the transmission line index, OR_l is the outage rate per year per
 332 line, T_l is the average outage duration for transmission line l in hours and
 333 Hrs is the total number of operating hours per year.

334 *Severity calculation*

We consider an *economic* severity function where the risk factor proposed is calculated based on the system costs encountered due to line failures. We consider mainly two costs: the costs of energy not served (estimated as a constant function in terms of €/MW) and the costs arising in a uniform-pricing market context for correcting the dispatch in real-time production. The latter represents the economic inefficiencies arising due to the strategic behavior in multiple-market interactions. Formally, this is formulated as:

$$Sev(E1_l) = cens_{a,l} \cdot x_{a,l}^{vg}, \quad \forall a \in N, \forall l \in L \quad (39)$$

$$Sev(E2_l) = [\gamma_l^* \cdot x_{j,l}^{*BM}] - [(\psi_l^* + \lambda^*) \cdot z_{j,l}^{*BM}], \quad \forall j \in J, \forall l \in L \quad (40)$$

Severity function (39) represents the effect of the energy not served, where $(cens_{a,l})$ is the cost of the energy not served at network bus (a) due to line (l) failure and $(x_{a,l}^{vg})$ is the amount of energy not served at bus (a) in case of such failure. Severity function (40) represents the effect of the schedule correction, considering the amount paid for upwards corrections $(\gamma_l^* \cdot x_{j,l}^{*BM})$ and the amount charged for downwards corrections $(\psi_l^* \cdot z_{j,l}^{*BM})$ minus the savings made from the generation reduction $(\lambda^* \cdot z_{j,l}^{*BM})$, for each line failure case. The risk assessment index considered is, thus, defined such as:

$$Risk(E_l) = \frac{OR_l \cdot T_l}{Hrs} \cdot [(cens_{a,l} \cdot x_{a,l}^{vg}) + (\gamma_l^* \cdot x_{j,l}^{*BM}) - ((\psi_l^* + \lambda^*) \cdot z_{j,l}^{*BM})],$$

$$\forall a \in N, \forall j \in J, \forall l \in L$$
(41)

$$SRisk = \sum_{l \in L} Risk(E_l)$$
(42)

335 where the aggregated system risk index (42) can be used in the comparison
 336 of the risk assessment for different power transmission systems.

337 3. Solution Method

338 The two MCPs formulated can be readily solved with available commer-
 339 cial solvers. For the present study we use the PATH solver [40] in the GAMS
 340 environment [41]. For the DC-OPF we use the IBM ILOG-CPLEX solver.
 341 The aim is to find the final feasible schedule in case of a line failure, tak-
 342 ing into account the GenCos DAM bidding, and subsequently to find both
 343 the upwards and the downwards BM prices and quantities bids used for the
 344 calculation of the risk index. For this multi-stage problem, we propose a
 345 solution method as follows:

- 346 1. Solve the DAM-MCP (17)-(19) to obtain the equilibrium DAM price
 347 (λ^*) and the generation units quantities bids (q_j^{*DAM}) .
 348 2. Solve the DC-OPF problem (27)-(36) given (q_j^{*DAM}) to obtain $(q_j^{OPF},$
 349 $x_j^{OPF}, z_j^{OPF}, x_a^{vg}, F_{(a,a')}, \delta_a, \delta_{a'}, u_a^{OPF}, w_a^{OPF})$.
 3. Calculate the total energy required for the upwards-balancing (UB)
 and the downwards-balancing (DB):

$$UB = \sum_{j \in J} x_j^{OPF} \quad (43)$$

$$DB = \sum_{j \in J} z_j^{OPF} \quad (44)$$

4. Since (u_a^{OPF}) and (w_a^{OPF}) are the upwards and downwards binary state
 for network bus (a), we translate these status to each unit (j) belonging
 to bus (a):

$$u_j^{OPF} = \begin{cases} 1, & \text{if } u_a^{OPF} = 1 \text{ and } j \in J_a \\ 0, & \text{otherwise} \end{cases} \quad (45)$$

$$w_j^{OPF} = \begin{cases} 1, & \text{if } w_a^{OPF} = 1 \text{ and } j \in J_a \\ 0, & \text{otherwise} \end{cases} \quad (46)$$

- 350 5. Solve the BM-MCP (20)-(26) given the values calculated in (43)-(46),
 351 and the known DAM price (λ^*) , to obtain the BM upwards and down-
 352 wards equilibrium market prices (γ^*, ψ^*) and quantities bids $(x_j^{*BM},$
 353 $z_j^{*BM})$, respectively.
 354 6. Calculate the risk index (41) for each line failure and finally the aggre-
 355 gated index (42).

356 4. Case study

357 *Numerical Example*

358 The power system under study is a 6-bus system adapted from the IEEE
 359 6-bus Reliability Test System [38]. Figure (1) shows the single line diagram of
 360 the adapted RBTS system. As shown, the system has 2 PV buses containing
 361 11 generation units (units 1 to 11), 5 PQ buses, and 7 transmission lines.
 362 Units 12 to 17 are the virtual generators used for the calculation of the
 363 amount of energy not served in their respective demand bus. The minimum
 364 and the maximum ratings of the generating units are 5 MW and 40 MW,
 365 respectively. The voltage level of the transmission system is 230 kV. The
 366 system has a peak load of 185 MW and the total installed capacity amounts
 367 to 240 MW. Table (1) illustrates the breakdown of the total available capacity
 368 and peak hour demand per network bus. Since no reactive power is considered
 369 in the network, it is assumed that bus voltages magnitudes are constant and
 370 equal to 1pu. Finally, Table (2) summarizes the technical characteristics of
 371 the transmission lines.

372 *Generation Units Breakdown in the Network*

373 Table (3) summarizes the maximum capacities and the cost data for each
 374 of the generation units. Table (4) illustrates the capacity limits and cost data
 375 for the virtual units. The ENS cost is calculated on the basis of 120 €/MWh,
 376 multiplied by the percentage of the demand present at the respective network
 377 bus. The capacity limits for the VGs are set to the maximum amount of load
 378 in each bus to ensure that no VG compensates for load shedding located in
 379 any network bus other than where it is placed. Finally, Table (5) illustrates

380 the transmission lines maximum capacities, the outage data expressed as the
 381 number of complete line outage for each line per year and the duration of this
 382 outage in hours. It is important to note that the maximum line capacities are
 383 chosen such that they would always be operated close to their limits under
 384 normal operating conditions (i.e. under no failure).

385 *GenCos Characterization*

386 Table (6) illustrates the GenCos characteristics. It is assumed that 4
 387 GenCos are competing in both markets, each owning different generation mix
 388 and different total production capacities. For the DAM and the BM, GenCos
 389 are assumed to have the ability to act strategically, which is represented by
 390 the conjectured-price response terms, as previously discussed. The values of
 391 the conjectured-price response for the DAM (θ_i) is assumed to be equal to
 392 0.2 for GenCos 1, 2 and 4, and equal to 0.1 for GenCo 3. This is to represent
 393 that a GenCo having the smallest capacity and some of the most expensive
 394 units (such as GenCo 3) would typically have less chances to exercise market
 395 power than the GenCos which have cheaper units more often committed. For
 396 the BM, the conjectured-price response (β_i and ϕ_i) are assumed to be equal
 397 to 0.1 for all GenCos. Finally, it is assumed that the cost functions for the
 398 generation units are linear.

399 **5. Results**

400 We solve the model simulating 8 different cases: the “base case”, where
 401 we do not consider any network line failures and is, thus, considered as the
 402 benchmark or the “business-as-usual” case for an hourly competition in a
 403 power system and cases (I to VII), where we consider the separate effects

404 of line 1 to line 7 failure, respectively. All the results reported consider the
 405 oligopolistic behavior of the GenCos, as the values of the conjectured-price
 406 response parameters in all markets (θ , β and ϕ) are different from zero.

407 Table (7) illustrates the production quantity bids for all GenCos obtained
 408 from the DAM-MCP, for all cases considered. Since the bidding decisions in
 409 the DAM do not depend on the line failure case ¹, the resulting bids do
 410 not change according the different line failures. These results only depend
 411 on the assumed level of the conjectured-price response parameters and the
 412 intrinsic characteristics of the generation units. It is important to note that
 413 units 3 to 11 possess enough capacity to satisfy all the network demand
 414 at a lower market price equal to ² or slightly higher than unit 3 marginal
 415 cost ³. However, since we model an oligopolistic market where ($\theta_i \neq 0$),
 416 the equilibrium model correctly portrays the GenCos behavior where units
 417 3 and 4 retract quantities offered to ensure that the more expensive units (1
 418 and 2) are committed and, thus, increase the uniform clearing market-price
 419 to the λ level shown in Table (13). These results are consistent with our
 420 expectations, and with the studies reviewed, which consider the ability of
 421 GenCos to exercise market power. Most notably, for the no-congestion case
 422 presented in [35], where market power is equally parametrized by conjecture
 423 price-response parameters, the authors reported similar results, showing that
 424 GenCos can increase the market price above the marginal level by modifying

¹We assume that the failure occurs after the DAM gate-closure and close to real-time dispatch.

²In case of perfect competition

³Both units 1 and 2 have higher marginal costs and typically would not be committed.

425 the production offers of their units.

426 Table (8) summarizes the aggregation of the GenCos bids per network
427 bus to clearly illustrate how the S.O. would validate the feasibility of the
428 schedule in the different failure cases.

429 Table (9) illustrates the solution of the DC-OPF problem which has the
430 objective of obtaining the real feasible schedule. It is shown that compared
431 to the pre-failures schedule, the different failure cases induce the need for
432 some upwards or downwards production adjustments along the buses with
433 active power output. This amount varies from one case to the other, already
434 providing an insight on the impact of the failure in terms of the amount of
435 ENS.

436 The amounts of the ENS per network bus calculated based on the mini-
437 mum cost objective are summarized in Table (10). It is shown that in both
438 the no failure case and Case I there is no ENS in the network. Since the
439 network flow limits can initially accomodate the required power dispatch, it
440 is clear that the schedule would remain unchanged if no failure occurs. If line
441 1 fails, the cheaper generation units 5 to 11 at bus 2 can no longer export all
442 of their production, a schedule correction is required, calling upon the more
443 expensive units 1 to 4 located at bus 1. However, the rest of the network can
444 still accomodate this modified schedule, and hence, no demand is curtailed.
445 The ENS amount varies in all other cases based on the updated topology of
446 the network, and on how much it allows for demand coverage.

447 Given these results, the BM-MCP is solved, and the equilibrium results of
448 the upwards and the downwards BM obtained are summarized in Tables (11)
449 and (12), respectively. The upwards balancing market is activated only in the

450 case of line 1 failure since it is the only failure case where there are generation
451 units on a network bus (bus 1) that have enough available upwards capacity
452 to compensate for the reductions required on the other bus (bus 2). In all the
453 other cases, there exist no units on the different buses that can compensate
454 for the power losses in the network and, therefore, demand is curtailed, and
455 only the downwards BM is activated.

456 The resulting upwards (γ) and downwards (ψ) BM prices are summarized
457 in Table (13). For Case I, the upwards BM (γ) is different than zero since the
458 market is activated. However, as shown, this market price is lower than the
459 DAM price (λ). This is due to the strategic behavior of the GenCos in the
460 DAM, where the expensive units (1 and 2) have already been committed to
461 their maximum capacities and, subsequently, only the cheaper units (3 and 4)
462 can participate in the subsequent market. The price, however, is still higher
463 than the marginal cost of both units 3 and 4, similarly representing the effect
464 of the parametrized strategic behavior of the GenCos in this market.

465 The analysis of the strategic bidding in the BM resembles that given
466 for the DAM. GenCos retract quantities offered by the cheaper units in the
467 upwards BM to ensure an increase in the market price. In the downwards
468 BM, this strategy works in the opposite sense: ideally the most expensive
469 unit able to reduce is committed for the downwards balancing, resulting
470 in the highest market price (highest since this market price is represented
471 as a negative term in the GenCos profit function). However, GenCos with
472 expensive units have incentives to bid lower quantities so that cheaper units
473 are committed for downwards balancing, thus ensuring a lower downwards
474 market price and, therefore, a higher profit. For a clear illustration of this

475 concept, it is important to consider that in the downwards BM, GenCos are
 476 only interested to participate if they are compensated in accordance to their
 477 “avoided fuel cost”, or otherwise, the net profit they would have made by
 478 being active in the DAM. Expensive units save more cost by being selected
 479 to reduce their production and, therefore, to compensate for their profit
 480 loss, are willing to bid higher. This is shown in downwards BM price (ψ)
 481 in Table (13). First, note that the negative market price indicates that
 482 the GenCos would actually be compensated for their participation in this
 483 market. For cases I to IV, units with cheaper marginal cost are required to
 484 reduce their productions. As discussed, their participation in this market
 485 drives the negative prices down and constitute a higher charge to be paid
 486 for their participation. For cases V to VII, only expensive units are called
 487 upon, resulting in higher negative prices and therefore a lower charge for
 488 their participation.

489 Since none of the reviewed studies considers explicitly the DAM and BM
 490 separation, we validate the results obtained by comparing them to what we
 491 would obtain out of the perfect competition outcome, which is well known
 492 from economics theory [42] and can be calculated analytically. For simple il-
 493 lustration, consider the perfect competition BM solution of Case IV. This can
 494 be obtained in the model by setting the conjecture-price response parameters
 495 (β and ϕ) to zero for all the GenCos, and solving for the required correc-
 496 tions, to obtain the bidding quantities and the market prices. We focus on
 497 the downwards BM, since it is the only correction market active in this case.
 498 Active units on bus 2 are required to bid for a reduction of 0.83 MWh; in
 499 this setting, and according to the outcome of perfect competition, we would

500 expect that one of the most expensive units on this network bus (one with
 501 a marginal cost of 0.8 €/ MWh) would bid its opportunity cost to undergo
 502 this reduction. This would be calculated as follows: the total revenue loss
 503 from reducing 0.83 MWh is this amount multiplied by the DAM price, or
 504 $0.83 * 19.125 = 15.874$ €; the production cost saved is equal to the marginal
 505 cost multiplied by the reduced amount, or $0.8 * 0.83 = 0.664$ €. Therefore,
 506 this GenCo would be willing to participate in the market if it was at least
 507 compensated the marginal loss of $(0.664 - 15.874)/0.83 = -18.325$ €/MWh.
 508 This is exactly the outcome obtained by solving the model, resulting in unit 5
 509 offering 0.83 MWh reduction and a clearing market price of -18.325 €/MWh.
 510 Notice that a much less competitive output occurs if one of the cheaper units
 511 with a marginal cost of 0.5 €/MWh become the marginal unit, resulting in a
 512 clearing price of -18.625 €/MWh. This is correctly portrayed in the results
 513 reported in Table (13), where we have considered a departure from the per-
 514 fect competition outcome by setting the parameter $\phi \neq 0$, which leads to a
 515 different offering than that of perfect competition and a consistently worse
 516 market clearing price equal to -18.367 €/MWh. This is similar for all the
 517 other cases presented.

518 The ENS and the schedule correction costs arising due to network line
 519 failure are thus calculated, and are summarized in Table (14). It can be seen
 520 that, in this numerical example, the ENS cost is significantly higher than
 521 the correction cost, indicating that it remains the most significant cost to
 522 consider for the risk assessment. However, it is important to note that a line
 523 failure can induce a need for a schedule correction without giving rise to ENS
 524 in the network, such as in Case I. Note also that this correction cost can be

525 positive or negative (from the S.O. perspective) depending on the failed line
526 and the resulting dispatch requirements, as well as the level of competition
527 in the BM. The total cost used to calculate the risk index is summarized in
528 Table (14).

529 Finally, the risk index values for all cases are shown in Table (15). This
530 index is to be used for identifying the effect of the failure taking into consider-
531 ation the market interactions among the GenCos, and can serve in comparing
532 the impact of the different failures. An important observation, is that within
533 a similar market context, a risk index that only considers the cost of ENS
534 in the severity function such as that presented in [31], would fail to identify
535 Case I presented in the system risk assessment. Moreover, it can underesti-
536 mate, or overestimate the economic impact of any of the failures, due to the
537 effects arising from the exercise of market power. Such an impact is shown to
538 become increasingly relevant as we depart further from the perfect competi-
539 tion behavior and portray GenCos that are able to manipulate the markets
540 to gain more profits.

541 In the previous section, we have analyzed in some depth a case study
542 based on the risk assessment method proposed. Next, we examine how much
543 this assessment is sensitive to the assumed level of competitiveness.

544 **6. Sensitivity Analysis**

545 Apart from the specific characteristics of the system under study (e.g. the
546 assumed generation units location, variable costs, units distribution among
547 the GenCos, etc.), the resulting quantity bids, schedules and market prices in
548 the model, and subsequently the risk level are dependent on the assumptions

549 related to the conjectured-price responses (θ_i , β_i , and ϕ_i) in the different
550 markets. As previously mentioned, these parameters are considered as being
551 exogenous in our work but it has been shown that they can be estimated or
552 endogenously calculated in real markets [43]. Therefore, it is of interest to
553 conduct a sensitivity analysis for these parameters to understand their effect
554 on system risk.

555 We conduct the analysis by solving the 7 cases of line failure while varying
556 the value of the conjecture price-response parameters (θ_i , β_i , and ϕ_i) from 0
557 to 1 with step size of 0.1, one at a time, resulting in a total of 9,317 cases.
558 We, then, aggregate the different costs arising and the risk indices for all 7
559 failure cases, to represent each of them as a single value under each level of
560 competition, resulting in a total of 1,331 aggregated schedule correction costs
561 and risk indices. The results are then plotted for a clear representation of
562 the changes in the cost and/or risk index with respect to the changes in the
563 different parameters. Since the plots produced are 4 dimensional, we divide
564 each plot into 3 Figures for clear representation, where we fix the value of
565 one parameter in each and plot the other two along with one of the variables.

566 Figure (2) illustrates the result of the sensitivity analysis for the schedule
567 correction costs arising due to all 7 line failures, with respect to the compe-
568 tition parameters. In Figures (2a, 2b and 2c) the value of parameters (θ , β
569 and ϕ) are fixed to zero. The ENS costs are not included in these graphs
570 as they are constant for all the cases and do not change with the change in
571 the competition parameters. It can be seen in Figure (2a) that the correc-
572 tion cost clearly increases as we increase the conjectured-price response (i.e.
573 market power) of the GenCos in both the upwards (β) and the downwards

574 (ϕ) BM. Furthermore, the parameter (ϕ) for the downwards BM affects this
 575 correction cost much more than that of the upwards BM (β). As we have
 576 shown in the previous section, the different line failures simulated more often
 577 resulted in the activation of the downwards BM than the upwards one. The
 578 lowest cost resulting from setting the parameters (β) and (ϕ) equal to zero
 579 (simulating the perfect competition case) is -263.97 €, indicating that the
 580 S.O. would actually receive back some of the costs paid for the generation in
 581 the DAM as they would finally not produce. On the other hand, assuming
 582 the highest exercise of market power for all GenCos in both BM results in
 583 a cost of 5292.75 €, highlighting the big impact that the exercise of market
 584 power can have on the system cost.

585 Figures (2b, 2c) show that the cost increasing trend does not hold with
 586 increasing the market power in the DAM through the parameter (θ). This is
 587 because the change in (θ) for each GenCo results in a change in their bidding
 588 behavior in the DAM; these different starting schedules lead to different
 589 correction requirements as the lines fail, possibly leading to less or cheaper
 590 corrections compared to the perfect competition schedule. This counter-
 591 intuitive result is only due to the fact that we do not take into consideration
 592 the energy price in the DAM, which significantly increases as we increase the
 593 market power of the GenCos in this market. Figures (3b, 3c) illustrate the
 594 cost trend when we include the DAM energy cost. It is clear how important
 595 the increase in the DAM price affects the system costs, as we increase the
 596 parameter (θ). Finally, although the results are shown for the values of the
 597 parameters (θ , β , and ϕ) set to zero, similar patterns are found when they
 598 are set to different levels (i.e. 0.1 or 0.9).

599 Since we are interested in quantifying the economic risk of line failures,
600 we revert to representing the sensitivity of the risk index without taking into
601 account the energy cost in the DAM. Figure (4) illustrates the sensitivity
602 analysis of the aggregated risk index and shows that it follows closely the
603 changes in the correction cost of the system shown in Figure (2). Such
604 representation could be especially useful in comparing the effect of different
605 levels of competition among the GenCos.

606 7. Conclusion

607 In the work presented in this paper, a novel risk assessment method for
608 network failures in an electricity market environment has been proposed.
609 The electricity market design considered is a uniform-pricing market with
610 counter-trading mechanism for correcting any network infeasibilities. A 3-
611 stage model has been proposed to model the operation of the electricity
612 system, consisting of:

- 613 • A conjectural-variation equilibrium model for simulating the compe-
614 tition in the DAM where the GenCos strategic behavior is modeled
615 through a conjectured-price response parameter.
- 616 • A DC-OPF model to simulate the feasible power dispatch in case of a
617 line failure.
- 618 • A conjectural-variation equilibrium model for simulating the counter-
619 trading mechanism, where the different GenCos submit bids for both
620 upwards and downwards correction of the dispatch.

621 Finally, an economic risk index has been proposed, which takes into account
622 the economic effects of a line failure, namely the cost of ENS and the schedule
623 correction cost.

624 The proposed method has been applied to a case study adapted from
625 the IEEE 6-bus reliability test system and the results have been analyzed
626 both technically and economically. Finally, a sensitivity analysis has been
627 performed to examine the effect of the changes in the competitiveness level of
628 the different market participants, portrayed in our model by the conjectured-
629 price response parameters, assumed to be exogenous to the problem.

630 It is shown that within a uniform-pricing market context, a cost arises
631 due to the schedule correction induced by a network contingency. Such a cost
632 is not reflected in the technical risk indices typically calculated, for example,
633 on the basis of voltage level and circuit flow violations, and is often neglected
634 also in the economic risk indices that typically consider only the ENS cost.
635 Our results show that this correction cost is, in fact, non-negligible and that
636 considering it is important because it could alter the relative importance of
637 the network contingencies. The proposed assessment can help the decision
638 maker properly categorizing the impact of the different line failures within a
639 uniform pricing market; this can be useful for deciding on maintenance sched-
640 ules, for example. Policy implications and market design recommendations
641 could also be derived but this is outside the scope of the present work.

642 Moreover, recognizing that the output of the model depends on the val-
643 ues of the conjectured-price response parameters assumed for the different
644 markets, the sensitivity analysis performed confirms that there is a linearly
645 increasing risk trend as we set those parameters to portray a less competitive

646 behavior from the GenCos in the BM, which is expected as it is where the
647 correction costs arise. This is not the case when varying the competitiveness
648 level of the GenCos in the DAM, as it is shown that this would result in
649 different initial production schedules and, therefore, different correction re-
650 quirements. It is, thus, necessary to be careful in estimating and setting the
651 values of these parameters when applying this assessment method.

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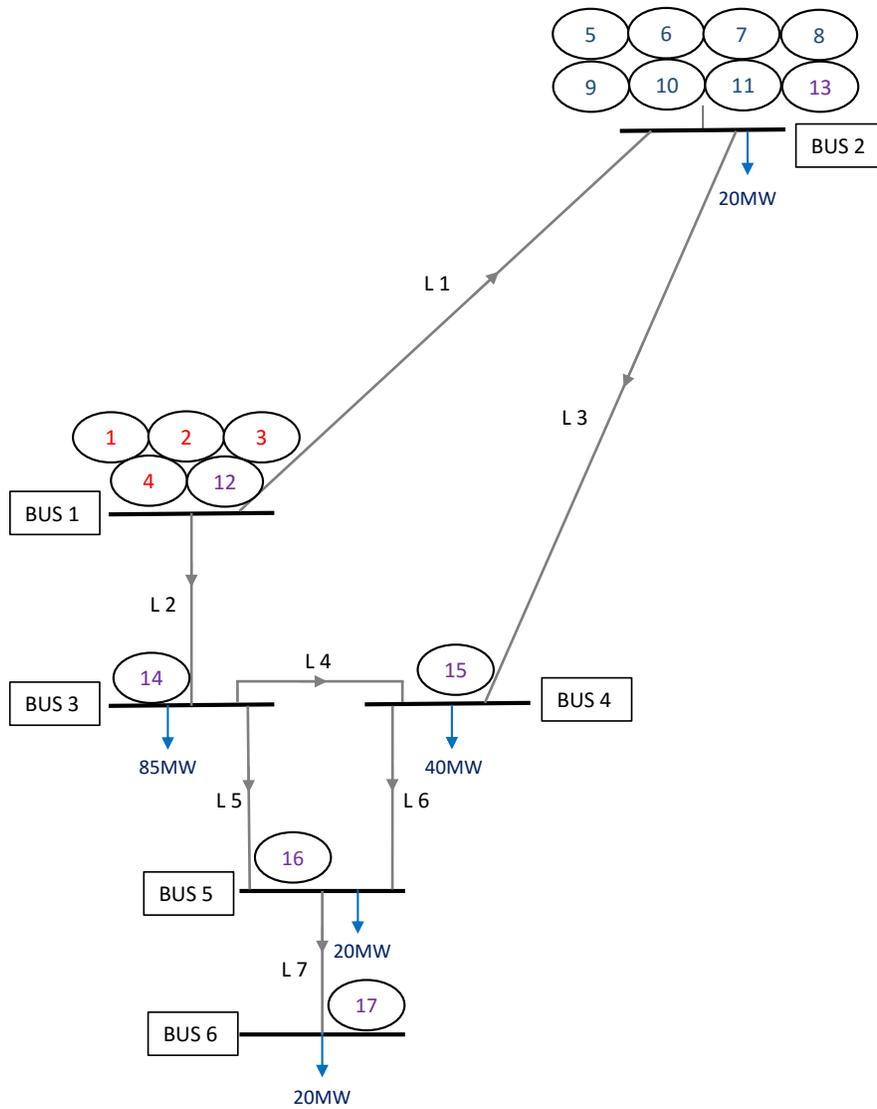


Figure 1: Generation units placement on the RBTS Single line diagram.

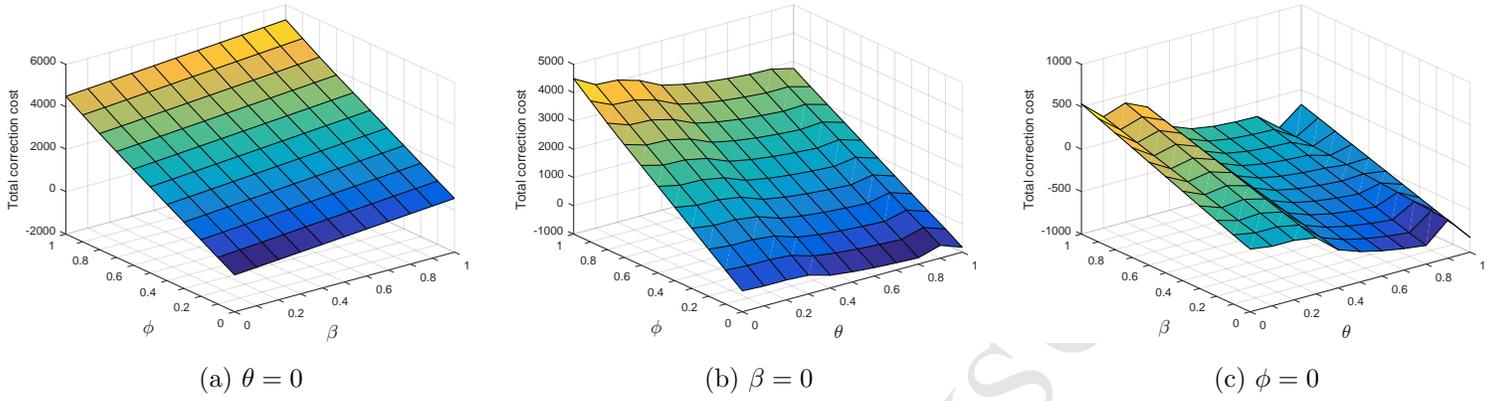


Figure 2: Sensitivity analysis for the correction cost arising due to line failures

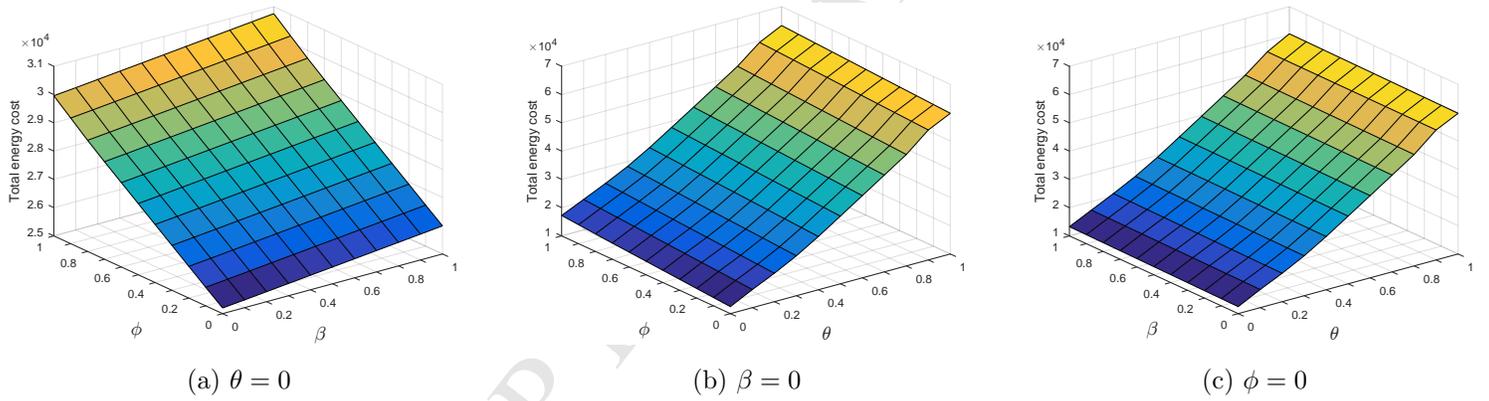


Figure 3: Sensitivity analysis for the total system costs (including energy cost in the DAM)

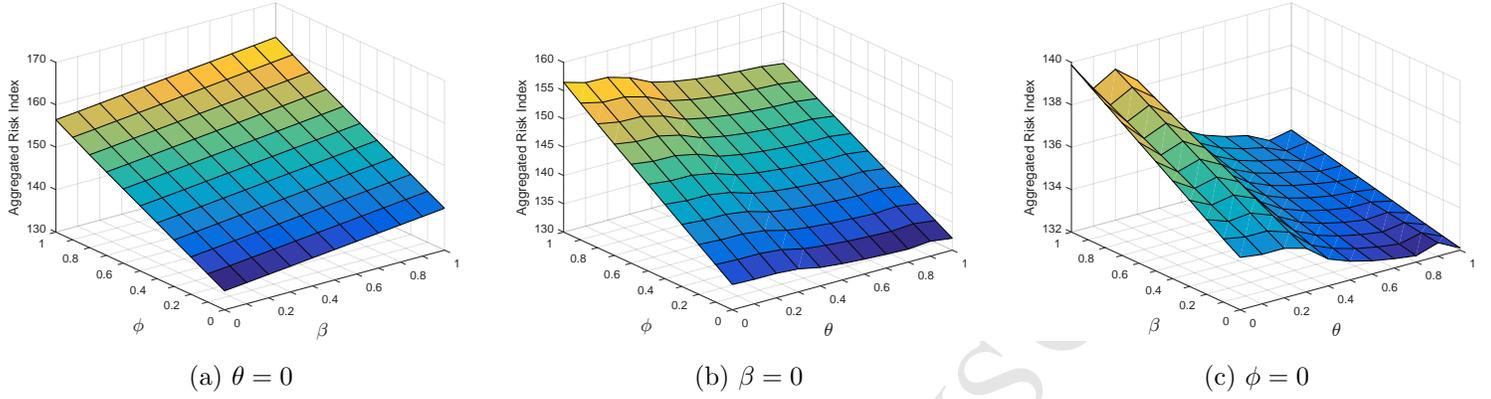


Figure 4: Sensitivity analysis for the aggregated risk index

Table 1: Bus Power Capacity and Bus Demand.

| Bus (a) | Total Available Capacity (MW) | Demand (MW) |
|-------------|----------------------------------|-------------|
| 1 | 110.00 | 0.00 |
| 2 | 130.00 | 20.00 |
| 3 | 0.00 | 85.00 |
| 4 | 0.00 | 40.00 |
| 5 | 0.00 | 20.00 |
| 6 | 0.00 | 20.00 |
| Total | 240.00 | 185.00 |

Table 2: Transmission lines Characterization

| Line (l) | Buses | | Line Length (Km) | Resistance R (p.u.) | Reactance X (p.u) | Susceptance B (p.u) |
|--------------|--------------|-------------|------------------|---------------------|-------------------|---------------------|
| | From (a) | To (a') | | | | |
| 1 | 1 | 2 | 200 | 0.0912 | 0.480 | 2.010 |
| 2 | 1 | 3 | 75 | 0.0342 | 0.180 | 5.362 |
| 3 | 2 | 4 | 250 | 0.1140 | 0.600 | 1.608 |
| 4 | 3 | 4 | 50 | 0.0228 | 0.120 | 8.043 |
| 5 | 3 | 5 | 50 | 0.0228 | 0.120 | 8.043 |
| 6 | 4 | 5 | 50 | 0.0228 | 0.120 | 8.043 |
| 7 | 5 | 6 | 50 | 0.0228 | 0.120 | 8.043 |

100 MVA base
230 kV base

Table 3: Generation Units Capacities and Cost Data.

| Unit (j) | Technology | Capacity (MW) | Variable costs, €/MWh | | |
|--------------|------------|---------------|-----------------------|----------------|---------------------|
| | | | Fuel Cost | Operation Cost | Total Variable Cost |
| 1 | Thermal | 10.00 | 10.00 | 3.50 | 13.50 |
| 2 | Thermal | 20.00 | 9.75 | 2.75 | 12.50 |
| 3 | Thermal | 40.00 | 9.75 | 2.50 | 12.25 |
| 4 | Thermal | 40.00 | 9.50 | 2.50 | 12.00 |
| 5 | Hydro | 5.00 | 0.65 | 0.15 | 0.80 |
| 6 | Hydro | 5.00 | 0.65 | 0.15 | 0.80 |
| 7 | Hydro | 20.00 | 480.45 | 0.05 | 0.50 |
| 8 | Hydro | 20.00 | 0.45 | 0.05 | 0.50 |
| 9 | Hydro | 20.00 | 0.45 | 0.05 | 0.50 |
| 10 | Hydro | 20.00 | 0.45 | 0.05 | 0.50 |
| 11 | Hydro | 40.00 | 0.45 | 0.05 | 0.50 |

Table 4: Load Shedding (Virtual Generators) cost data.

| Bus (a) | Technology | Capacity (MW) | ENS (€/MWh) | Cost |
|-------------|-------------------|---------------|----------------|------|
| 2 | Virtual Generator | 20.00 | 132.97 | |
| 3 | Virtual Generator | 85.00 | 175.13 | |
| 4 | Virtual Generator | 40.00 | 145.94 | |
| 5 | Virtual Generator | 20.00 | 132.97 | |
| 6 | Virtual Generator | 20.00 | 132.97 | |

Table 5: Transmission lines Capacities and outage data

| Line (l) | Buses | | Maximum Line Ca- capacity (MW) | Permanent Outage rate (per year) | Outage duration (hours) |
|--------------|--------------|-------------|---|---|-------------------------------|
| | From (a) | To (a') | | | |
| 1 | 1 | 2 | 45.00 | 4.00 | 15.00 |
| 2 | 1 | 3 | 100.00 | 1.50 | 15.00 |
| 3 | 2 | 4 | 70.00 | 5.00 | 15.00 |
| 4 | 3 | 4 | 20.00 | 1.00 | 15.00 |
| 5 | 3 | 5 | 20.00 | 1.00 | 15.00 |
| 6 | 4 | 5 | 25.00 | 1.00 | 15.00 |
| 7 | 5 | 6 | 20.00 | 2.00 | 15.00 |

Table 6: Characterization of GenCos

| Agent | θ_i | β_i | ϕ_i | Unit | Bus | Marginal Cost | \bar{q}_j |
|-------|--|--|--|------|-----|----------------------|-------------|
| i | $\left[\frac{\text{€}/MWh}{MW}\right]$ | $\left[\frac{\text{€}/MWh}{MW}\right]$ | $\left[\frac{\text{€}/MWh}{MW}\right]$ | j | a | $[\text{€}/MWh][MW]$ | |
| 1 | 0.2 | 0.1 | 0.1 | 3 | 1 | 12.25 | 40.00 |
| | | | | 5 | 2 | 0.80 | 5.00 |
| | | | | 7 | 2 | 0.50 | 20.00 |
| 2 | 0.2 | 0.1 | 0.1 | 8 | 2 | 0.50 | 20.00 |
| | | | | 10 | 2 | 0.50 | 20.00 |
| | | | | 11 | 2 | 0.50 | 40.00 |
| 3 | 0.1 | 0.1 | 0.1 | 1 | 1 | 13.50 | 10.00 |
| | | | | 2 | 1 | 12.50 | 20.00 |
| | | | | 6 | 2 | 0.80 | 5.00 |
| 4 | 0.2 | 0.1 | 0.1 | 4 | 1 | 12.00 | 40.00 |
| | | | | 9 | 2 | 0.50 | 20.00 |

Table 7: GenCos DAM quantity bids

| Agent i | Unit j | No Fail- ure | q_j^{DAM} [MWh] | | | | | | |
|--------------|-------------|--------------------|-------------------|------------|-------------|------------|-----------|------------|-------------|
| | | | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| 1 | 3 | 9.38 | 9.38 | 9.38 | 9.38 | 9.38 | 9.38 | 9.38 | 9.38 |
| | 5 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 |
| | 7 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 |
| 2 | 8 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 |
| | 10 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 |
| | 11 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 |
| 3 | 1 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 |
| | 2 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 |
| | 6 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 |
| 4 | 4 | 15.62 | 15.62 | 15.62 | 15.62 | 15.62 | 15.62 | 15.62 | 15.62 |
| | 9 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 | 20.00 |

Table 8: GenCos quantity bids per network bus (a)

| Bus (a) | No Fail- ure | $\sum_{j \in J_a} q_j^{DAM}$ [MWh] | | | | | | |
|------------|--------------------|------------------------------------|------------|-------------|------------|-----------|------------|-------------|
| | | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| 1 | 55.00 | 55.00 | 55.00 | 55.00 | 55.00 | 55.00 | 55.00 | 55.00 |
| 2 | 130.00 | 130.00 | 130.00 | 130.00 | 130.00 | 130.00 | 130.00 | 130.00 |

Table 9: Feasible production schedule per network bus (a)

| Bus (a) | No Fail- ure | $\sum_{j \in J_a} q_j^{OPF}$ [MWh] | | | | | | |
|------------|--------------------|------------------------------------|------------|-------------|------------|-----------|------------|-------------|
| | | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| 1 | 55.00 | 95.00 | 0.00 | 55.00 | 55.00 | 42.33 | 41.67 | 39.88 |
| 2 | 130.00 | 90.00 | 90.00 | 65.00 | 129.17 | 127.67 | 123.33 | 125.12 |

Table 10: Amount of ENS per network bus (*a*)

| Bus (<i>a</i>) | No Fail- ure | x_a^{vg} [MWh] | | | | | | |
|---------------------|--------------------|------------------|------------|-------------|------------|-----------|------------|-------------|
| | | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| 2 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 0.00 | 0.00 | 55.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | 0.00 | 0.00 | 0.00 | 25.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5 | 0.00 | 0.00 | 20.00 | 20.00 | 0.00 | 0.00 | 20.00 | 0.00 |
| 6 | 0.00 | 0.00 | 20.00 | 20.00 | 0.83 | 15.00 | 0.00 | 20.00 |

Table 11: GenCos quantity bids in the Upwards Balancing Market

| Agent | Unit | No Fail- ure | x_j^{*BM} [MWh] | | | | | | |
|-------|------|--------------------|-------------------|------------|-------------|------------|-----------|------------|-------------|
| | | | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| 1 | 3 | 0.00 | 18.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 5 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 7 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | 8 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 1 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 2 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 6 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | 4 | 0.00 | 21.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 9 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table 12: GenCos quantity bids in the downwards Balancing Market

| Agent | Unit | No Fail- ure | z_j^{*BM} [MWh] | | | | | | |
|-------|------|--------------------|-------------------|------------|-------------|------------|-----------|------------|-------------|
| | | | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| 1 | 3 | 0.00 | 0.00 | 9.38 | 0.00 | 0.00 | 3.75 | 6.25 | 6.25 |
| | 5 | 0.00 | 5.00 | 5.00 | 5.00 | 0.415 | 0.00 | 0.00 | 0.00 |
| | 7 | 0.00 | 6.67 | 7.29 | 15.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | 8 | 0.00 | 11.67 | 20.00 | 20.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 10 | 0.00 | 0.00 | 1.67 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 1 | 0.00 | 0.00 | 10.00 | 0.00 | 0.00 | 10.00 | 10.00 | 10.00 |
| | 2 | 0.00 | 0.00 | 20.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 6 | 0.00 | 5.00 | 0.00 | 5.00 | 0.415 | 0.00 | 0.00 | 0.00 |
| 4 | 4 | 0.00 | 0.00 | 15.62 | 0.00 | 0.00 | 1.25 | 3.75 | 3.75 |
| | 9 | 0.00 | 11.67 | 6.04 | 20.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table 13: DAM and BM prices

| Market | Market Prices [€/ MWh] | | | | | | | |
|-----------|------------------------|---------|---------|----------|---------|--------|---------|----------|
| | No Fail- ure | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
| λ | 19.125 | 19.125 | 19.125 | 19.125 | 19.125 | 19.125 | 19.125 | 19.125 |
| γ | 0 | 14.125 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| ψ | 0 | -19.792 | -20.792 | -20.625 | -18.367 | -7.250 | -7.50 | -7.50 |

Table 14: Costs arising due to network line failures

| | No Failure | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
|---------------------|------------|--------|----------|----------|---------|---------|---------|----------|
| Probability | | 0.68% | 0.26% | 0.86% | 0.17% | 0.17% | 0.17% | 0.34% |
| ENS Cost [€] | 0.00 | 0.00 | 14951.50 | 8967.55 | 110.80 | 1994.55 | 2659.40 | 2659.40 |
| Correction Cost [€] | 0.00 | 591.67 | 158.33 | 97.50 | -0.63 | -178.13 | -232.50 | -232.50 |
| Total Cost [€] | 0.00 | 591.67 | 15109.83 | 9065.05 | 110.17 | 1816.42 | 2426.90 | 2426.90 |

Table 15: Risk Index for the network

| | No Fail- ure | Case I | Case II | Case III | Case IV | Case V | Case VI | Case VII |
|------------|-----------------|--------|---------|----------|---------|--------|---------|----------|
| Risk Index | 0.00 | 4.02 | 39.29 | 77.96 | 0.18 | 3.09 | 4.13 | 8.25 |

- A risk assessment method for power network failures in a market context is proposed.
- It quantifies the economic impact due to the strategic reactions of the participants.
- The method consists of game theory models and a DC-OPF model solved sequentially.
- Exercise of market power by participants alters the risk level of the network failure.

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