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Redispatching in an interconnected electricity system with high renewables penetration

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Abstract

Grid congestion management is gaining importance in certain parts of the European electricity grid. The deployment of renewable electricity sources at locations with a weak grid connection and far from the load centers can lead to overloading of transmission lines. Redispatching, i.e., rearranging scheduled generation and consumption, might be needed to obtain a feasible and safe operational state of the electricity system. This paper studies the impact of three parameters on the redispatching quantities and costs: (1) loop flows through the electricity system, (2) an increase in renewable generation in remote areas, and (3) a curative and preventive N-1 security criterion. Towards this aim, a dedicated generation scheduling model is developed, consisting of a day-ahead market and a redispatch phase. The Belgian power system is considered as case study. Three general conclusions can be drawn from this paper. First, it is important to consider loop flows when quantifying redispatching, especially in a highly interconnected electricity system as the European system. The case study shows that loop flows can more than double the need for redispatching. Second, transmission grid constraints might restrict the deployment of renewables in certain areas. Third, relaxing the N-1 security criterion in congested grid areas from preventive to curative can drastically reduce the redispatch costs.

Keywords: Congestion management, redispatching, renewables integration, loop flows, N-1 security.

Nomenclature

Sets

I (index i)	set of conventional power plants (subset I_{nuc} contains nuclear units)
J (index j)	set of renewable generation units
L (index l)	set of transmission lines
N (index n)	set of nodes

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11 S (index s) set of line contingencies

T (index t) set of time steps

12 Parameters

$A^{PLANT}_{n,i}$	matrix linking power plants to nodes {0,1}
$A^{RES}_{n,j}$	matrix linking renewable units to nodes {0,1}
C_i	generation cost at minimum power output [EUR/h]
CC_j	cost of curtailment [EUR/h]
$D_{n,t}$	electricity load [MW]
$\overline{F_{l,s}}$	transmission capacity of a line [MW]
LC	cost of lost load [EUR/MWh]
MC_i	marginal generation cost [EUR/MWh]
13 MDT_i	minimum down time [h]
MUT_i	minimum up time [h]
$\overline{P_i}$	maximum power output [MW]
$\underline{P_i}$	minimum power output [MW]
$PTDF_{l,n,s}$	power transfer distribution factors
SR^+	required upward spinning reserve [MW]
SR^-	required downward spinning reserve [MW]
SUC_i	start-up cost [EUR/start-up]
$RES_{j,t}$	available renewable generation [MW]

14 Variables

$curt^{RD}_{j,t,s}$	renewables curtailment (redispatch) [MW]
$g^{DA}_{i,t}$	power generation above minimum output (day-ahead) [MW]
$g^{RD}_{i,t,s}$	power generation above minimum output (redispatch) [MW]
$inj^{RD}_{n,t,s}$	grid injection (redispatch) [MW]
$ll^{RD}_{n,t,s}$	loss of load (redispatch) [MW]
15 $v^{DA}_{i,t}$	start-up status (day-ahead) {0,1}
$v^{RD}_{i,t}$	start-up status (redispatch) {0,1}
$w^{DA}_{i,t}$	shut-down status (day-ahead) {0,1}
$w^{RD}_{i,t}$	shut-down status (redispatch) {0,1}
$z^{DA}_{i,t}$	on/off-status (day-ahead) {0,1}
$z^{RD}_{i,t}$	on/off-status (redispatch) {0,1}

1. Introduction

Transmission constraints restrict the amount of electric power that can be transported between two points in the grid. A grid congestion occurs whenever the physical or operational transmission limit of a line is reached or violated [1]. Congestion management can be defined as all actions taken to avoid or relieve congestions in the electricity grid [2].

Congestion management is becoming increasingly important in a system with a high penetration of intermittant renewables. According to ENTSO-E, the association of European Transmission System Operators for Electricity, 80% of the bottlenecks identified in the European grid are directly related to renewables integration [3]. Renewable generation units are often installed in areas with a high load factor, but not necessarily close to the load center or to the existing high voltage grid (e.g., offshore wind farms) [4]. ENTSO-E distinguishes between direct connection issues (i.e., the connection between the renewable generation unit and the existing grid) and congestion issues (i.e., congestion in the existing grid between the renewable generation unit and the load center). The latter is dealt with in this paper.

Often, transmission constraints are only taken into account to a limited extent in electricity markets. The market clearing algorithm determines the accepted generation and consumption bids within a bidding zone, and the exchange with other zones.[1] The transmission limits between different bidding zones are considered in the market clearing, but transmission constraints within a bidding zone are neglected. This can lead to grid congestions which need to be solved by proper congestion management.

Different forms of congestion management are discussed in the literature. One can distinguish between a centralized or a decentralized approach [5]. According to the first approach, one centralized entity is responsible for managing grid congestions. This entity is typically the Transmission System Operator (TSO) or the Independent System Operator (ISO). In such centralized approach, generators and consumers trade electricity and schedule their generation and consumption units without taking account of the grid constraints within their bidding zone. The system operator then undertakes all required actions after the market clearing to avoid line overloading within the bidding zone. One of the possible remedial actions is redispatching. Redispatching is defined as rearranging the generation (and consumption) schedule in order to obtain a feasible schedule that respects all transmission constraints

[1]Allocation of the cross-border capacity to generators or consumers can happen explicitly or implicitly. In explicit cross-border allocation, a market player first has to obtain the right to use the cross-border capacity before electricity can be traded with a market player in another bidding zone. In implicit cross-border allocation, cross-border capacity is allocated together with the trade of electricity between different bidding zones.

[6],[7],[8]. Other short-term remedial actions are changing the set point of flexible transmission systems like phase shifting transformers [9]. On the longer run, the system operator might invest in grid reinforcements to solve structural grid congestions [10],[11],[12]. According to the decentralized approach, the size of bidding zones is reduced and more transmission constraints are taken into account in the market clearing (i.e., the transmission constraints between the bidding zones). In the limit, every node in the electricity grid is a bidding zone. The result is locational price signals, i.e., electricity prices which can differ between different places in the grid when congestion occurs [13]. On the short term, locational electricity prices give an incentive to generate and consume electricity at places in the grid which do not lead to congestion [14],[15]. On the longer term, locational price signals would drive generators and consumers to install new generation or consumption units at places in the grid with little grid congestion.

Redispatching is an important congestion management measure in the European electricity sector, and this for two reasons. First, a centralized approach to congestion management is implemented, where the TSOs have the responsibility to avoid grid congestions within their bidding zone. Second, due to the rapid deployment of renewable electricity, grid congestions become more common. On the short term, redispatching is the main tool for the TSO to relieve the grid congestions. Due to these two reasons, one sees an increase in redispatching in the European electricity grid [6]. In Germany, for instance, redispatching is a pressing issue at the time of writing.

This paper focusses on redispatching as congestion management tool. The aim of this study is to quantify the redispatch quantities and costs for a realistic case study, and investigate the impact of loop flows, increasing renewable generation and the N-1 security criterion. Towards this aim, the Belgian electricity system is studied in detail. The Belgian system is an exemplary case to illustrate the congestion issues that can arise due to renewables deployment. Belgium aims to integrate a considerable amount of offshore wind generation, but the current grid connection between the shore and the main load centers is rather weak, causing grid congestions. Similar situations occur in other places in the European grid. Although the results presented in this paper are case-specific, general trends and conclusions can be derived.

This paper addresses congestion management with a market oriented approach. The focus lies on the market design in place to deal with congestion management and the redispatching that results from it. In this regard, a proper modeling of the generation portfolio is important in order to take account of dynamic power plant constraints which can impact redispatch costs (e.g., minimum up and down times). Another approach to congestion management is taken by a series of papers which focuses on the computational challenges related to models that determine a safe and secure grid operation, i.e., Optimal Power Flow (OPF) models [16]. An OPF determines the optimal network operation. A Security Constrained Optimal Power Flow (SCOPF) is a generalization of the OPF that additionally considers a set of postulated contingencies in the OPF [17]. The (SC)OPF is a non-linear, non-convex, optimization problem which makes it hard to solve for large-scale electricity systems. However, large scale studies exist which present SCOPF case studies of, for instance, Great Britain [18] and Poland [19].

The added value of this paper to the existing literature is twofold. First, the results presented in this paper follow from a case study with very detailed grid data and time series, based on a real-life electricity system. This unlike most market-oriented case studies on redispatching presented in the literature, which typically use a simplified or methodological test system [9],[8],[12]. Second, this paper studies quantitatively the impact of various parameters on redispatching (loop flows, increased renewable generation, and N-1 security criterion) whereas the existing literature takes these parameters as fixed. This paper complements the existing literature and indicates the complexity of redispatching.

The paper proceeds as follows. Section 2 gives an overview of the different redispatch options and costs for the TSO. Section 3 describes the dedicated model that is developed to simulate the day-ahead generation scheduling and the redispatching phase. Section 4 presents the Belgian electricity system as case study. Section 5 presents and discusses the results. Finally, section 6 concludes.

2. Redispatch actions and costs

Electricity markets in Europe are zonal markets, meaning that every bidding zone is represented as one single node and connected to other nodes by cross-border links.[2] As a result, the market clearing does not take into account transmission limits within a bidding zone, and this may lead to technically infeasible generation schedules. At this point, the TSO comes into play. The TSO performs an ex-post analysis to validate the feasibility of the generation schedule. If grid congestions occur within the bidding zone, the TSO issues redispatch orders to generators to reschedule their generation.

The TSO can issue different types of redispatch orders, each with a related cost (or revenue);

[2] Most bidding zones in Europe coincide with countries, e.g., Belgium is one bidding zone, but exceptions exist. For instance, Germany and Austria are one bidding zone.

- A TSO can request an increase in power output of a conventional generation unit.[3] In return, the generator will expect a compensation for increasing its power output, equal to at least the additional generation cost. The additional generation cost consists of the cost for additional fuel, CO_2 emissions and possibly extra start-ups.

- A TSO can request a decrease in power output of a conventional generation unit. The generator will pay the TSO to decrease its power output, equal to at most the avoided generation cost.[4] The avoided generation cost consists of the cost for the non-used fuel, CO_2 emissions and possibly avoided start-ups.

- A TSO can request a decrease in renewable generation, if technically, practically and regulatory feasible.[5] The renewable generator will expect a compensation for curtailing its generation equal to at least the missed financial support for renewables (assuming a zero marginal generation cost).

Figure 1 gives a schematic overview of the possible redispatch actions and costs for the TSO. The following numbers are used in this study and can give an idea of the costs and revenues related to redispatch orders. The marginal generation costs of conventional units range from 18 EUR/MWh for nuclear units to 95 EUR/MWh for open-cycle gas turbines. The renewable support for curtailable renewables goes from 0 to 100 EUR/MWh. The cost used in this paper for loss of load and curtailment of renewables with priority access is 10,000 EUR/MWh (i.e., indicating system infeasibilities). The net redispatch cost of the TSO will always be positive as the starting point of the redispatch phase, i.e., the day-ahead market outcome, is the result of a minimization of generation costs (without considering grid constraints). In the redispatch phase, expensive generation, which was not scheduled in the day-ahead market, needs to replace cheaper generation, which was scheduled in the day-ahead market.

Other redispatch actions than the ones mentioned in this section might be possible, such as topological actions and the use of phase shifters. However, they are not dealt with in this paper as they are not applicable to the considered case study. Topological actions are not used by the TSO to avoid redispatching of conventional generation units due to the short-term and time-variable character of

[3]Conventional generation units refer to centralized and dispatchable units. In this paper, conventional generation units refer to nuclear units and gas fired units (no coal fired units are operational in the considered electricity system).

[4]The running generation units have sold their electricity already in the day-ahead market at the day-ahead price. Conventional generators have the same pay-off when they run and incur generation costs then when they are off-line and pay the avoided generation costs to the TSO.

[5]A renewable generation unit can be used for redispatching purposes if curtailment of its power output is technically feasible, can be measured for billing purposes and is allowed by regulation.

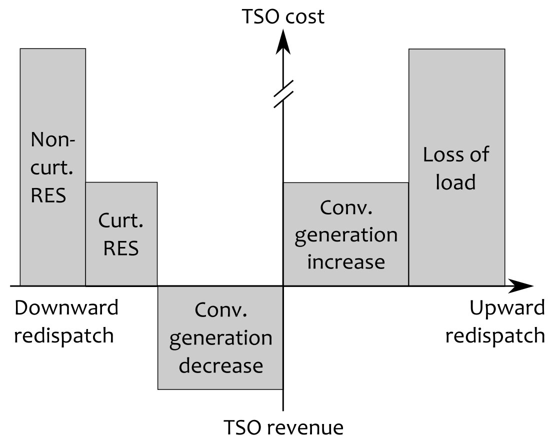

Figure 1: Schematic overview of possible redispatch actions for the Transmission System Operator (TSO) (RES: renewables, Curt.: curtailment, Conv.: conventional).

redispatching, especially when caused by intermittent renewable generation. Moreover, by not using topological actions for short-term congestion management, a certain margin is still available to guarantee a safe grid operation, which can be used to deal with grid maintenance situations. No phase shifters are present within the studied electricity network (although there are phase shifters installed on the borders of the considered case study but they are used to control loop flows through the system and not for solving local congestions within the grid).

Note that this paper only deals with day-ahead congestions caused by neglecting network constraints within bidding zones in the day-ahead market. Congestions which occur intra-day or real-time due to contingencies or large variations in renewable generation are not discussed. However, a similar approach as presented in this paper can be used to address the latter (although possibly without contingency constraints).

3. Model description

To study redispatching, the authors have developed a dedicated model. The model consists of two sub-models which are solved sequentially, reflecting a two-step approach. In a first step, the optimal day-ahead generation schedule is determined, without taking into account the transmission limits within the bidding zone. In a second step, the day-ahead generation schedule is evaluated by means of a DC power flow and redispatch actions are taken to avoid transmission line overloading in the bidding zone. This two-step approach corresponds to the actual market design in which generators first schedule their generation units without considering intra-zonal transmission limits, followed by a feasibility evaluation of the generation schedule by the TSO.

The optimal day-ahead generation schedule is determined by a unit commitment model. The output of the unit commitment model is the generation schedule that fulfills load at minimal operational generation cost. As already mentioned, transmission constraints within the considered bidding zone are not considered in this first step. Commercial exchange of electric power with neighboring bidding zones is limited by the Net Transfer Capacity (NTC) of the cross-border connections.

If the day-ahead generation schedule is infeasible due to grid constraints, generation needs to be rearranged. Any deviation from the day-ahead generation schedule will result in a net cost for the TSO as generation needs to be replaced by more expensive generation. The optimal redispatch schedule is determined by a redispatch model that minimizes the cost for the TSO. However, the possible redispatch actions are constrained by the unit commitment decision taken in the day-ahead market. The redispatch model determines a curative N-1 secure system operation, meaning that the solution of the redispatch model is able to deal with line contingencies if curative actions are allowed after the contingency occurred. Curative actions refer to changing the economic dispatch of conventional generation units and changing the curtailment of renewables [16].

The optimization model presented in this paper is meant to be used for market oriented studies of redispatching, and can be used towards this aim by researchers, policy makers, TSOs and regulators. Both sub-models -unit commitment and redispatch- are formulated as mixed-integer linear programs in GAMS and solved with CPLEX 12.6, using an optimality criterion of 0.1%. The considered time period is one year with an hourly time step. The models solve blocks of two days, with one day overlap to ensure a correct coupling between the consecutive days.[6]

The applied methodology entails certain assumptions. First, the study is fully deterministic, meaning that no stochastic variables are considered (e.g., wind power forecast errors). The input parameters are the same in the day-ahead market and the redispatch model and are assumed to be perfectly known to all generators in advance. Second, the models use an hourly time step since the day-ahead markets in Europe are currently based on an hourly time resolution. Within this time resolution, not all variations in the time series for load and renewable generation are seen. Moreover, the (technical) ramping constraint of conventional units is not restricting on an hourly basis; no ramping constraints are considered in this study. Third, the modeling framework assumes a centrally cleared and perfectly

[6]The one-day overlap is based on the largest minimum up/down time in the generation portfolio (i.e., a 24 hour minimum up/down time for nuclear units, see Table 1). By working with a one-day overlap, the model considers the full length of the nuclear minimum up/down time when taking a decision to start-up/shut-down a nuclear unit at the end of the first considered day.

competitive electricity market. In Belgium (and other European countries), electricity is traded day-ahead bilaterally and through power exchanges with (simplified) bidding. However, assuming a perfect competitive market, the market outcome of both market designs is very similar. Fourth, it is assumed that all conventional units can be called upon by the TSO for redispatching at a cost (revenue) equal to the additional (avoided) generation cost for increasing (decreasing) their power output. However, this might not be the case as the bidding strategies and generation costs are private and confidential information.

3.1. Day-ahead model (unit commitment)

The objective function of the unit commitment model is the minimization of the operational generation cost:

$$min \sum_t \sum_i C_i\, z_{i,t}^{DA} + MC_i\, g_{i,t}^{DA} + SUC_i\, v_{i,t}^{DA} \tag{1}$$

For clarification on the symbols, the reader is referred to the nomenclature section at the outset of the paper. The generation cost consists of generation costs (fuel and CO_2 emissions) and start-up costs. The objective function is subject to the market clearing constraint (equation 2), generation limits of conventional units (equation 3), minimum up and down time constraints (equations 4-5), the logic relation between different states of the power plants (equation 6), upward and downward spinning reserves (equations 7-8), binary constraints (equation 9) and non-negative constraints (equation 10), all displayed here below:

$$\sum_i (z_{i,t}^{DA}\, \underline{P_i} + g_{i,t}^{DA}) = \sum_n D_{n,t} - \sum_j RES_{j,t} \qquad \forall\, t \tag{2}$$

$$0 \leq g_{i,t}^{DA} \leq (\overline{P_i} - \underline{P_i})\, z_{i,t}^{DA} \qquad \forall\, i, t \tag{3}$$

$$z_{i,t}^{DA} \geq \sum_{t'=t+1-MUT_i}^{t} v_{i,t'}^{DA} \qquad \forall\, i, t \tag{4}$$

$$1 - z_{i,t}^{DA} \geq \sum_{t'=t+1-MDT_i}^{t} w_{i,t'}^{DA} \qquad \forall\, i, t \tag{5}$$

$$z_{i,t-1}^{DA} - z_{i,t}^{DA} + v_{i,t}^{DA} - w_{i,t}^{DA} = 0 \qquad \forall\, i, t \tag{6}$$

$$\sum_{i \notin I_{nuc}} \left((\overline{P_i} - \underline{P_i})\, z_{i,t}^{DA} - g_{i,t}^{DA} \right) \geq SR^{+} \qquad \forall\, t \tag{7}$$

$$\sum_{i \notin I_{nuc}} g_{i,t}^{DA} \geq SR^{-} \qquad \forall\, t \tag{8}$$

$$z_{i,t}^{DA}\,,\, v_{i,t}^{DA}\,,\, w_{i,t}^{DA} \in \{0, 1\} \qquad \forall\, i, t \tag{9}$$

$$g_{i,t}^{DA} \geq 0 \qquad \forall\, i, t \tag{10}$$

The unit commitment model, as presented in this section, is based on [20].

3.2. Redispatch model

The objective function of the redispatch model aims at minimizing the redispatch cost for the TSO:

$$\begin{aligned} min \sum_{t} \sum_{i} \Big(& C_i\,(z_{i,t}^{RD} - z_{i,t}^{DA}) + MC_i\,(g_{i,t,1}^{RD} - g_{i,t}^{DA}) + SUC_i\,(v_{i,t}^{RD} - v_{i,t}^{DA}) \Big) \\ & + \sum_{t} \sum_{j} CC_j\, curt_{j,t,1}^{RD} + \sum_{t} \sum_{n} LC\, ll_{n,t,1}^{RD} \end{aligned} \tag{11}$$

Again, the reader is referred to the nomenclature section at the outset of the paper for clarification on the symbols. Only the N-situation is considered in the objective function (s equal to 1), but all N-1 situations are considered in the constraints. The objective function is subject to the market clearing constraint (equation 12), the day-ahead on/off-decision for nuclear units (equation 13), generation limits of conventional units (equation 14), minimum up and down time constraints (equations 15-16), the logic relation between different states of the power plants (equation 17), upward and downward spinning reserves (equations 18-19), curtailment limits (equation 20), loss of load limits (equation 21), grid limitations (equations 22-23), binary constraints (equation 24) and non-negative constraints (equation 25), as follows:

$$\sum_i A_{n,i}^{PLANT}\,(z_{i,t}^{RD}\,\underline{P_i} + g_{i,t,s}^{RD}) + \sum_j A_{n,j}^{RES}(RES_{j,t} - curt_{j,t,s}^{RD}) = D_{n,t} - ll_{n,t,s}^{RD} + inj_{n,t,s}^{RD} \qquad \forall\, n,t,s \tag{12}$$

$$z_{i,t}^{RD} = z_{i,t}^{DA} \quad \forall\, i \in I_{nuc}, t \tag{13}$$

$$0 \leq g_{i,t,s}^{RD} \leq (\overline{P_i} - \underline{P_i})\, z_{i,t}^{RD} \qquad \forall\, i,t,s \tag{14}$$

$$z_{i,t}^{RD} \geq \sum_{t'=t+1-MUT_i}^{t} v_{i,t'}^{RD} \qquad \forall\, i \notin I_{nuc}, t \tag{15}$$

$$1 - z_{i,t}^{RD} \geq \sum_{t'=t+1-MDT_i}^{t} w_{i,t'}^{RD} \qquad \forall\, i \notin I_{nuc}, t \tag{16}$$

$$z_{i,t-1}^{RD} - z_{i,t}^{RD} + v_{i,t}^{RD} - w_{i,t}^{RD} = 0 \qquad i,t \tag{17}$$

$$\sum_{i \notin I_{nuc}} \left((\overline{P_i} - \underline{P_i})\, z_{i,t}^{RD} - g_{i,t,1}^{RD}\right) \geq SR^{+} \qquad \forall\, t \tag{18}$$

$$\sum_{i \notin I_{nuc}} g_{i,t,1}^{RD} \geq SR^{-} \qquad \forall\, t \tag{19}$$

$$curt_{j,t,s}^{RD} \leq RES_{j,t} \qquad \forall\, j,t,s \tag{20}$$

$$ll_{n,t,s}^{RD} \leq D_{n,t} \qquad \forall\, n,t,s \tag{21}$$

$$-\overline{F_{l,s}} \leq \sum_n PTDF_{l,n,s}\, inj_{n,t,s}^{RD} \leq \overline{F_{l,s}} \qquad \forall\, l,t,s \tag{22}$$

$$\sum_{n} inj^{RD}_{n,t,s} = 0 \qquad \forall\, t, s \tag{23}$$

$$z^{RD}_{i,t}\,,\, v^{RD}_{i,t}\,,\, w^{RD}_{i,t} \in \{0,1\} \qquad \forall\, i, t \tag{24}$$

$$g^{RD}_{i,t,s}\,,\, curt^{RD}_{j,t,s}\,,\, ll^{RD}_{n,t,s}\,,\; inj^{RD}_{n,t,s} \geq 0 \qquad \forall\, i, t, s \tag{25}$$

The redispatch model is developed by the authors and dedicated to this study. A DC power flow model of the electricity network is being used. The main advantage of a DC power flow model is its linearity compared to the non-linear AC power flow model. This allows solving large power systems for multiple time steps in a limited run time. The disadvantage of a DC power flow is its reduced accuracy. The literature mentions, for high voltage grids, an average 5% deviation between line flows in a DC power flow model and in an AC power flow model [21]. However, the use of a DC power flow is justified in this paper given its focus on yearly aggregated redispatch quantities and costs, rather than on particular line flows in specific hours.

4. The Belgian power system as case study

The case study presented in this paper is the expected Belgian 2016 system (see Figure 2). Belgium has a well developed and meshed high voltage grid, connecting the main load and generation centers. Therefore, grid congestions and congestion management were never a pressing issue for the Belgian TSO in the past. However, this has changed due to the deployment of offshore wind power in the Belgian North Sea. Over the last years, about 800 MW of offshore wind power has been commissioned. This raises congestion issues as the transmission grid connecting the shore with the 380 kV grid was not designed to accommodate large landward power flows from offshore wind. As a result, congestions in the existing 150 kV grid in the coastal area become more apparent. At the same time, injections of onshore renewable generation in this area are increasing as well, further worsening the situation. The Belgian case is exemplary for the difficulties associated with the deployment of renewable generation in areas where the grid was not built to accommodate these new injections.[7]

[7] The Belgian TSO is, at the time of writing, strengthening the grid with a new 380 kV connection between the shore and the existing 380 kV grid. This new connection is not expected to be in place before the end of 2016.

The model to simulate the electricity grid in this study is a detailed DC power flow model with 161 nodes and 241 line elements (transmission lines, transformers and couplings). The whole Belgian 380 kV transmission grid is included, together with the 150 kV grid in the Western part of Belgium. The remaining part of the 150 kV grid and the 220 kV grid are represented by equivalent lines and nodes. The grid model allows to study grid congestions in the coastal region in detail. Not all line contingencies are considered in the N-1 analysis. Eight critical line outages are determined ex-ante by the TSO experts and taken into account in the redispatch optimization. In an N-1 situation, transmission flows can go to 120% of the rated line capacity.

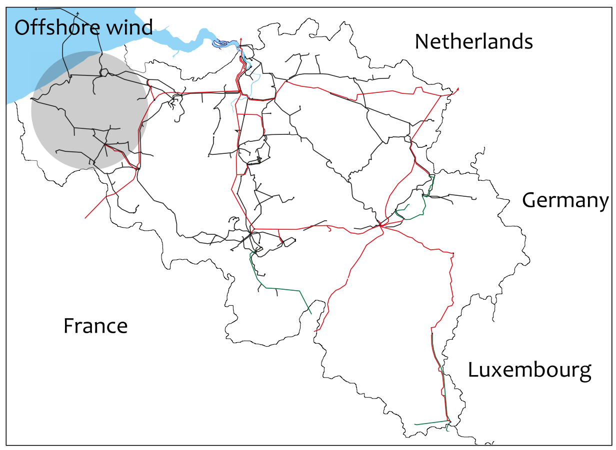

Figure 2: Overview of the Belgian high voltage grid (red: 380 kV lines, green: 220 kV lines, black: 150 kV lines) [22]. Grid congestions occur in the grey area between the offshore wind farms in the North Sea and the 380 kV grid.

Historical nodal load measurements are scaled up and used as demand time series. The annual electric energy demand is 90.2 TWh, with a peak demand of 13.9 GW in the winter and the lowest demand in the summer of about 6 GW. About 7% of the electricity consumption is located in the coastal region. The load time series are corrected for commercial exchange with neighboring countries. The commercial cross-border trade is imposed on the model as an exogenous parameter. In the case study, Belgium imports on an annual basis 10.8 TWh from France and 3.3 TWh from the Netherlands. Note that no direct connection with Germany exists at the present time.

The generation portfolio consists of 23 conventional generation units, with an aggregated capacity of 8.6 GW. Table 1 shows the technical parameters and generation costs allocated to the conventional generation units [23]. In this study, the authors assume that all online conventional units can ramp-up and ramp-down for redispatching purposes. Gas fired units (combined-cycle gas turbines and open-cycle gas turbines) can also start-up and shut-down for redispatching purposes. Nuclear units cannot

	Units	$\sum \overline{P}$ [GW]	$\underline{P}$ [% $\overline{P}$]	MUT,MDT [h]	C [EUR/h]	MC [EUR/MWh]	SUC [kEUR/start]
NUC	6	5.1	95	24	8,000-18,000	18	6
CCGT	9	2.9	35	3	1,200-16,000	65-95	83-555
OCGT	8	0.6	30	1	1,000-4,000	70-85	28

Table 1: Overview of technical characteristics per technology (NUC: nuclear, CCGT: combined-cycle gas turbines, OCGT: open-cycle gas turbines, $\overline{P}$: maximum power output, $\underline{P}$: minimum power output, MUT: minimum up time, MDT: minimum down time, C: generation cost at $\underline{P}$, MC: marginal generation cost, SUC: start-up cost) [23].

change their on/off-state for redispatching purposes due to too large minimum up and down times.

Historical time series for renewable generation and generation from cogeneration units are scaled up and used. Renewable generation refers to generation from conventional hydro, wind energy (offshore and onshore), bio-energy and photovoltaic energy. Three types of renewables are considered, based on the curtailment cost for redispatching purposes. One distinguishes onshore renewable generation with a flexible contract, offshore wind generation and onshore renewable generation with priority grid access. The flexible onshore renewable generation is located in the coastal area and connected to the grid under the condition that the TSO can curtail them at zero cost for redispatching purposes. About 180 MW of renewable generation capacity is operated under such a flexible capacity, accounting for a generation of 0.4 TWh/a. Offshore wind can be curtailed in the redispatch phase at the cost of the financial support for offshore wind generation, i.e., 100 EUR/MWh. By 2016, 870 MW of offshore wind capacity is expected in the Belgian North Sea, accounting for a generation of 3.1 TWh/a (i.e., normal wind year with a load factor of 40 %). The onshore renewable generation capacity with priority access to the grid is about 6.2 GW, responsible for a yearly generation of 11.2 TWh. The redispatch model allows curtailment of these last renewable generation units only at a very high cost of 10,000 EUR/MWh. Moreover, 4.1 GW of cogeneration units (electric capacity) is installed, with a yearly electricity generation of 23.5 TWh/a. No curtailment of cogeneration units is allowed.

Recall that the studied power system is the expected 2016 Belgian power system, based on hypotheses regarding the development of generation capacity and demand. The authors are not responsible for the realisation of these hypotheses. The results of the paper can only be interpreted correctly taken into account these hypotheses.

5. Results and discussion

This section presents the redispatch quantities and the redispatch costs due to grid congestions in the considered case study. First the reference case is presented, i.e., the anticipated Belgian 2016 power system. In the following subsections, the impact of loop flows, increasing offshore wind and the N-1 security criterion are discussed.

5.1. Reference scenario: Belgian 2016 power system

The day-ahead market outcome for the reference scenario is shown on Figure 3. In terms of TWh/a, the system load is mainly covered by renewable generation and cogeneration units (42%), nuclear generation (38%) and import (16%). CCGTs generate 2.5 TWh/a (load factor of the operating CCGTs is only 18%; part of the CCGT units is never used) and OCGTs generate 1 TWh/a (load factor of 17%). These gas units are mainly brought online to fulfil the spinning reserve requirement. The total annual generation cost (fuel, CO_2 emissions and start-ups, excluding the cost of import) is 899 Mio EUR.

This day-ahead market solution then possibly needs to be adapted to get a feasible generation schedule that takes account of the grid constraints. The feasibility of the day-ahead generation schedule can be checked by calculating the grid flows through all transmission lines resulting from the day-ahead generation schedule, and this for the N-state and each considered N-1 state. If the capacity of at least one transmission line is exceeded, redispatching will be needed. It turns out that during 1,972 hours of the year (23% of the time), grid congestions occur and redispatching will be needed.

The TSO has one option for upward redispatching -increasing conventional generation (Conv+)- and two for downward redispatching -decreasing conventional generation (Conv-) and curtailing flexible onshore renewable generation and offshore wind (RES-). From the redispatch simulation follows that 34.3 GWh/a of upward redispatching is required. The amount of upward and downward redispatching is by definition equal (the electricity demand still has to be met). The downward redispatching consists of 29.3 GWh/a of conventional generation that is ramped down and 5 GWh/a of curtailed renewable generation. Overall, the amount of redispatching is rather limited as only 0.08% of the annual load is redispatched.[8] Loss of load and curtailment of renewable generation with priority access is only possible at the very high cost of 10,000 EUR/MWh, indicating system infeasibilities. However, neither loss of load nor curtailment of renewable generation with priority access occurs in the reference case. The annual redispatch cost is 2.9 Mio EUR.

[8] The redispatch simulations indicate redispatch due to two reasons; grid congestions and renewables curtailment. In the day-ahead market, no renewables curtailment is allowed, while in the redispatch phase curtailment of flexible onshore renewables and offshore wind is possible. If renewables curtailment is a cost-efficient measure, the model will perform curtailment in the redispatch phase and reduce overall system costs (i.e., a net income for the TSO). However, this study only deals with redispatching due to grid congestions. Therefore the numbers shown in this paper refer only to redispatching due to grid congestions.

The total amount of downward redispatching, i.e., 34.3 GWh/a, can be split up in 15 GWh/a of downward redispatching in the coastal area and 19.3 GWh/a of downward redispatching in the rest of Belgium. The downward redispatching in the coastal area is a direct consequence of grid congestions (i.e., there is not enough transmission capacity to transport all planned generation from the coastal area landward). Downward redispatching in the rest of Belgium is caused by the minimum operating point of the units delivering upward redispatching. If a unit starts up for redispatch purposes, that unit has to operate above its minimum operating point. Therefore, additional downward redispatching might be needed elsewhere.

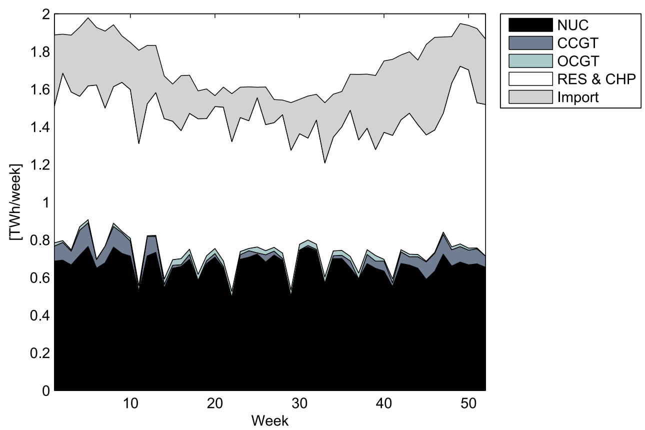

Figure 3: Weekly day-ahead generation schedule in the reference scenario (NUC: nuclear, CCGT: combined-cycle gas turbines, OCGT: open-cycle gas turbines, RES: renewables, CHP: cogeneration).

5.2. Impact of loop flows

In the reference case, only the commercial exchange of electricity with the neighboring countries was considered. However, the actual power flows on the cross-border lines can largely deviate from the commercial cross-border exchange, due to loop flows. Loop flows are power flows through the Belgian grid caused by injections or withdrawals in other parts of the European grid. As these loop flows enter and leave the control area (by the same amount), they do not impact the net exchange position of the Belgian system, but they do impact the flows through the transmission lines in the Belgian system and hence also the need for redispatching. This is clarified in an example below.

Loop flows are particularly important in a highly interconnected electricity grid like the European grid. The Belgian electricity grid is connected to the Netherlands in the north and to France in the south. The northern border has a Net Transfer Capacity (NTC-value) of 1,000 to 1,500 MW and the southern border has a NTC-value of 2,000 to 2,500 MW, both for the importing direction [24].[9] The NTC-values are given to the electricity market as import/export constraint and used for commercial exchange between different market zones.

To check the effect of loop flows, an annually fixed loop flow is added to the commercial cross-border flow in the redispatch phase. The positive direction of the loop flow is defined from north to south (i.e., from the Netherlands to France). Consider, for instance, a certain time step where Belgium imports commercially net 1,000 MW from France in the south and 500 MW from the Netherlands in the north (net exchange position of Belgium is -1,500 MW). If a loop flow of 100 MW is imposed, the resulting physical flow on the southern border is 900 MW (net import) and 600 MW on the northern border (net import). The net exchange position of the Belgium area stays the same (-1,500 MW), but the power flows within the Belgium system are impacted by the loop flow.

Figure 4 and Figure 5 show the impact of loop flows on the amount of redispatching and the redispatch costs, respectively. Loop flows are varied from -2,000 MW to 2,000 MW in steps of 500 MW. The zero loop flow scenario corresponds to the reference case discussed in the previous subsection. Figure 4 shows, for each loop flow scenario, the amount of upward redispatching (left bar, consisting of increasing conventional generation and loss of load) and the amount of downward redispatching (right bar, consisting of decreasing conventional generation and renewables curtailment). As explained before, the amount of upward and downward redispatching are equal. The impact of loop flows on redispatching is considerable. The redispatched energy and the redispatch costs more than double for large negative loop flows, i.e., northward loop flows. At a loop flow of -2,000 MW, loss of load is needed in the simulations, indicating system infeasibilities (all nodal load can no longer be met). Curtailment of renewables with priority access, i.e., another system infeasibility, never occurs. It turns out that loop flows from the south to the north strongly increase the need for redispatching, whereas loop flows in the other direction have a more modest impact on redispatching. This can be understood as follows; grid congestions are mainly caused by west-east flows in the coastal region (offshore wind generation needs to be transported from the Sea in the west to the main load centers landinward). A loop flow from France to the Netherlands increases this west-east flow as part of the loop flow will enter Belgium in the south-west and leave Belgium in the north-east. A loop flow from the Netherlands to France counteracts the west-east flow, relieving congestion in this direction. However, a north-south loop flow

[9] The NTC-value of a cross-border link depends on the direction (import or export) and the considered moment in time.

causes new congestions on the north-south lines in the coastal area. Both effects cancel each other out, resulting in more or less stable redispatch costs for increasing north-south loop flows. Recall that in this section, it was assumed that a constant loop flow occurs during the whole year. In reality, different loop flows occur every hour, changing in magnitude and direction.

Loop flows can - to a certain extent - be mitigated by phase shifting transformers.[10] The redispatch cost savings that can be obtained by mitigating loop flows can be read from Figure 5 by comparing the costs in a loop flow scenario with the cost in a zero loop flow scenario. Installing a phase shifter to mitigate redispatch costs can be interesting if the avoided redispatch costs surpass the investment and maintenance costs over the life time of the phase shifter (although various other aspects should be considered, such as the controllability of the phase shifter).

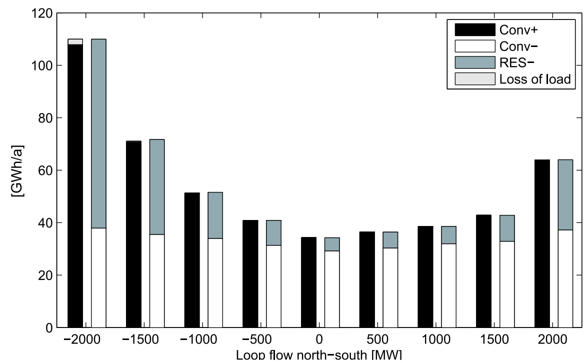

Figure 4: Impact of loop flows on redispatching for 9 loop flow scenarios. The left bar of each loop flow scenario shows the amount of upward redispatching (Conv+: increased conventional generation, and loss of load) and the right bar the amount of downward redispatching (Conv-: decreased conventional generation, and RES-: decreased flexible onshore renewable generation and offshore wind generation). Large negative loop flows can more than double the amount of redispatching.

5.3. Impact of increasing offshore wind

To investigate the effect of increasing offshore wind capacity, a sensitivity analysis is performed. The installed offshore wind capacity is varied from 800 MW to 2,300 MW in steps of 500 MW (offshore wind capacity in the reference case is 870 MW, expected offshore wind capacity by 2020 is about 2,300 MW). The offshore wind generation profile is scaled up in proportion to the installed capacity. This increased offshore generation impacts both the day-ahead generation schedule and the need for redispatching. The redispatching model considers only a case with zero loop flows.

[10]There are phase shifting transformers installed on the Belgian border with the Netherlands and with France, with the aim to mitigate loop flows.

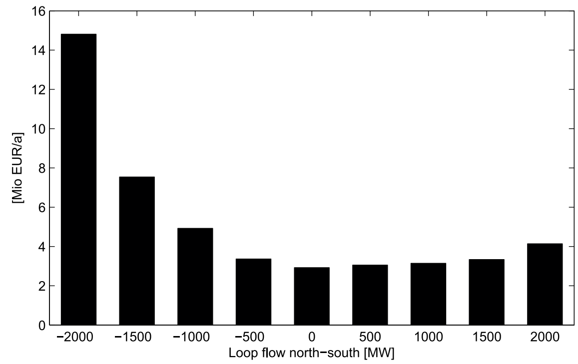

Figure 5: Impact of loop flows on redispatch costs for 9 loop flow scenarios (excluding loss of load cost). Redispatch costs increase drastically for large negative loop flows.

The increase in offshore wind generation in the day-ahead market is compensated by a decrease in generation from nuclear power plants and gas fired power plants. Offshore wind generation increases from 2.8 TWh/a to 8.1 TWh/a for 800 MW and 2,300 MW of installed capacity, respectively. Additional offshore wind generation pushes out first the most expensive conventional units, i.e., gas fired power plants. However, additional offshore wind generation increases the need for flexibility which is preferably delivered by gas fired generation. These two effects cancel out each other, resulting in both a decrease in gas fired generation and nuclear generation for an increasing amount of offshore wind capacity (see Figure 6). The operational generation cost decreases with increasing offshore wind generation, from 901 Mio EUR for 800 MW offshore wind capacity to 779 Mio EUR for 2,300 MW offshore wind capacity.

Figure 7 and Figure 8 show the amount of redispatching and the redispatch costs for increasing offshore wind capacity. The amount of redispatching and the redispatch costs increase drastically with increasing offshore wind generation. For 2,300 MW of offshore wind capacity, about 3% of the annual electricity demand needs to be redispatched. As of 1,800 MW of offshore wind, loss of load occurs in the redispatch simulations, indicating system infeasibilities. It might seem counter-intuitive that more installed offshore wind capacity leads to more loss of load, but more offshore wind generation reduces the upward redispatch options. Due to more offshore wind generation, some nuclear units are shut down during certain days in the day-ahead generation schedule. These nuclear units cannot be started up again in the model for redispatching purposes when it turns out that not all scheduled offshore generation can be transported to the load centers. This might lead to loss of load in the redispatch phase. The redispatch costs rise drastically for increasing offshore wind capacity (see Figure 8). This increase is to a large extent caused by the curtailment of offshore wind at a cost of 100 EUR/MWh. At high installed offshore wind capacities, most of the generation of every additional MW offshore wind has to be curtailed to avoid line overloading.[11]

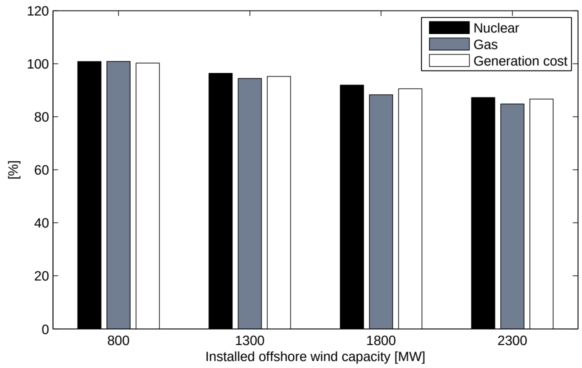

Figure 6: Impact of additional offshore wind capacity on conventional generation and operational generation costs in the day-ahead market. The figure shows the annual nuclear generation, the annual gas generation and the annual generation system costs, all expressed relatively to the reference case with 870 MW offshore wind capacity.

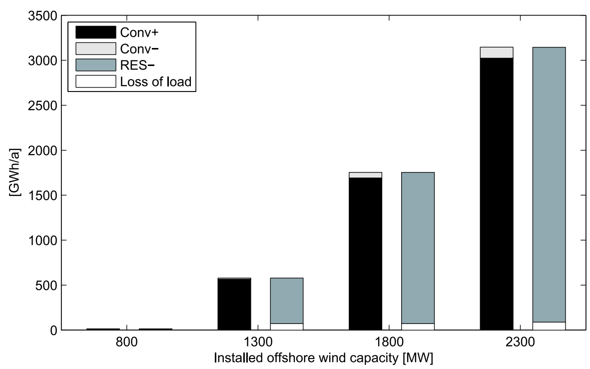

Figure 7: Impact of additional offshore wind on redispatching. The left bar of each offshore wind scenario shows the amount of upward redispatching (Conv+: increased conventional generation, and loss of load) and the right bar the amount of downward redispatching (Conv-: decreased conventional generation, and RES-: decreased flexible onshore renewable generation and offshore wind generation). The amount of redispatching explodes above 1,000 MW offshore wind capacity.

5.4. Impact of preventive N-1 security criterion

A curative N-1 security criterion has so far been implemented in the redispatch phase. In a curative N-1 secure system, the economic dispatch of conventional units and the curtailment of renewables can be changed after the line contingency occurred. In a preventive N-1 secure system, a line contingency has to be passed without changing the economic dispatch or curtailment. A preventive N-1 secure system

[11]The Belgian TSO is, at the time of writing, strengthening the grid connection between the shore and the main load centers inland in order to accommodate an increase in offshore wind.

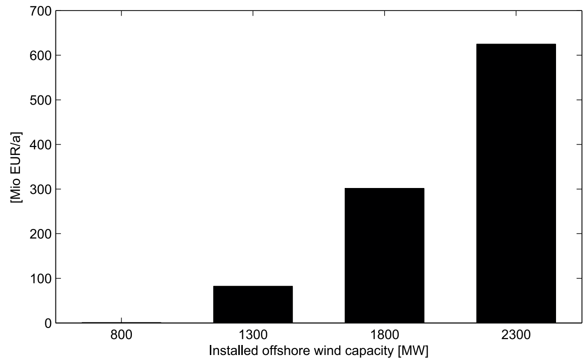

Figure 8: Impact of additional offshore wind on redispatch costs (excluding loss of load cost). Redispatch costs explodes with increasing offshore wind.

is hence more stringent than a curative system. This subsection discusses the impact on redispatching of the more stringent preventive N-1 security criterion, compared to a curative N-1 security criterion. The redispatch model is extended with the following three equations to impose a preventive N-1 security criterion, instead of a curative one:

$$g_{i,t,s}^{RD} = g_{i,t,1}^{RD} \qquad \forall\, i, t, s \tag{26}$$

$$curt_{j,t,s}^{RD} = curt_{j,t,1}^{RD} \qquad \forall\, j, t, s \tag{27}$$

$$ll_{n,t,s}^{RD} = ll_{n,t,1}^{RD} \qquad \forall\, n, t, s \tag{28}$$

Equations 26-27-28 impose on the model that the economic dispatch, renewables curtailment and loss of load have to be the same for every N-1 situation.

Figure 9 shows the impact of the N-1 security criterion on the redispatch quantities for the reference case (i.e., 870 MW offshore wind, no loop flows). Without an N-1 security criterion, almost no redispatching is required. With a curative N-1 security criterion, 34.3 GWh/a of redispatching is needed (i.e., the reference case). This increases to 220 GWh/a in case of preventive N-1 security. With preventive N-1, loss of load occurs, indicating system infeasibilities.

The redispatch cost increases from 0.2 Mio EUR without an N-1 security criterion to 2.9 Mio EUR with curative N-1 and 25.9 Mio EUR with preventive N-1. This allows to determine the cost of N-1 security as the difference between the cost with and without N-1 security. For the considered power system, the annual cost of a curative N-1 criterion is 2.7 Mio EUR and 25.7 Mio EUR for a preventive N-1 criterion.

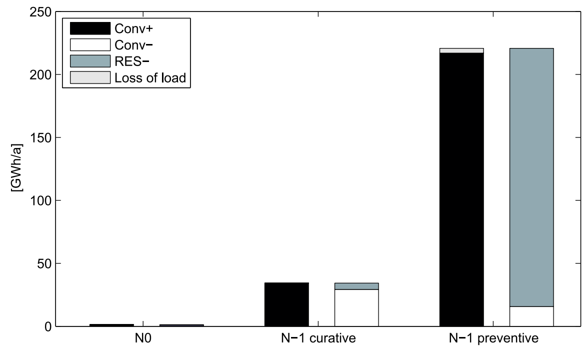

Figure 9: Impact of the N-1 security criterion on redispatching. The left bar of each security criterion shows the amount of upward redispatching (Conv+: increased conventional generation, and loss of load) and the right bar the amount of downward redispatching (Conv-: decreased conventional generation, and RES-: decreased flexible onshore renewable generation and offshore wind generation). The amount of redispatching depends heavily on the N-1 security criterion.

6. Conclusions

This paper discusses redispatching as tool for congestion management in interconnected electricity systems with a high penetration of renewables. The Belgian electricity system is studied as a case study. The Belgian system is embedded in the European electricity system and faces grid congestion issues due to the deployment of offshore wind without a strong grid connection between the shore and the main load centers inland. Based on the results presented in this paper, three conclusions can be drawn.

First, it is shown that loop flows can have a considerable impact on redispatching. Loop flows are unintended power flows through a bidding zone, caused by injections and withdrawals outside the bidding zone. In the case study, redispatch quantities and costs increase with more than a factor 2 at high loop flows. Loop flows are relevant in a highly interconnected electricity system such as the European system. One can conclude that the impact of loop flows is too large to neglect and should therefore be considered, in particular in a highly interconnected power system.

Second, redispatch amounts and costs can increase drastically when additional (renewable) generation is added to congested areas. In the case study, the increase in redispatching amounts and costs with increasing offshore wind capacity is very steep. One can conclude that transmission grid constraints restrict the deployment of renewables in certain areas, once grid congestions start to occur.

Third, it is shown that the stringency of the N-1 security criterion imposed to the system has a large impact. In the case study, redispatch costs are a factor 8 higher if a preventive N-1 security criterion is imposed, compared to a curative N-1 security criterion. One can conclude that relaxing the stringency of the N-1 security criterion, i.e., going from preventive to curative N-1 security, can reduce redispatch costs drastically.

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