Electric Power Systems Research 127 (2015) 64–72

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Redispatching in an interconnected electricity system with high renewables penetration

K. Van den Bergh [a], D. Couckuyt [b], E. Delarue [a], W. D'haeseleer [a,*]

[a] University of Leuven (KU Leuven) Energy Institute, Celestijnenlaan 300 Box 2421, B-3001 Leuven, Belgium
[b] Elia System Operator, Boulevard de l'Empereur 20, B-1000 Brussels, Belgium

ARTICLE INFO

Article history:
Received 21 January 2015
Received in revised form 29 April 2015
Accepted 25 May 2015
Available online 9 June 2015

Keywords:
Congestion management
Redispatching
Renewables integration
Loop flows
N-1 security
Redispatching costs

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.

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

[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.

* Corresponding author. Tel.: +32 16 322 510.
E-mail address: william.dhaeseleer@kuleuven.be (W. D'haeseleer).

http://dx.doi.org/10.1016/j.epsr.2015.05.022
0378-7796/

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
S (index s) set of line contingencies
T (index t) set of time steps

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]
$\bar{F}_{l,s}$	transmission capacity of a line [MW]
LC	cost of lost load [EUR/MWh]
MC_i	marginal generation cost [EUR/MWh]
MDT_i	minimum down time [h]
MUT_i	minimum up time [h]
$\bar{P}_i$	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]

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]
$v^{DA}_{i,t}$	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}

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 [6–8]. 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 [10–12]. 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.