Electric Power Systems Research 141 (2016) 124–136

Contents lists available at ScienceDirect

Electric Power Systems Research

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

A nodal-based security-constrained day-ahead market clearing model incorporating multi-period products

Grigoris A. Dourbois, Pandelis N. Biskas *

Department of Electrical and Computed Engineering, Aristotle University of Thessaloniki, 54124 Thessaloniki, Greece

ARTICLE INFO

Article history:
Received 24 December 2015
Received in revised form 18 June 2016
Accepted 16 July 2016

Keywords:
Locational Marginal Prices
Multi-period products
AC Load Flow
Apparent power
Line Outage Distribution Factors
Paradoxically Accepted Blocks

ABSTRACT

A model for the solution of a European-type day-ahead market with multi-period products is presented in this paper, considering a nodal network representation and including N and $N-1$ transmission security constraints. An iterative process is employed, similar to the process implemented in the U.S. markets, coordinating a market clearing problem (formulated as a Mixed Integer Linear Programming—MILP model) with an AC Load Flow solution, in order to check the apparent power flows of transmission lines against their respective limits, accounting the influence of voltage magnitudes and reactive power on the system lines' power flows and calculate the Locational Marginal Prices—LMPs. A distributed-slack bus modelling is used, in order to ensure the robustness of the attained LMPs, so that they are independent of the selection of the system reference node. The model is evaluated in terms of pricing and computational efficiency using the Balkan nodal power system.

1. Introduction

Many milestones have been accomplished recently to achieve a fully operational Internal Electricity Market (IEM) in compliance with specific directives issued by the European Commission. Important steps have been accomplished towards this direction through the voting and the implementation of the Third Energy Package, Directive 2009/72/EC, and the launching of the Price Coupling of Regions initiative (PCR), which aimed at the clearing of the European day-ahead market utilizing a price coupling algorithm. Indisputably, a crucial issue for the efficient operation of the integrated European electricity market is the handling of congestion management (CM) in the European transmission network. Several studies on European day-ahead market coupling have been presented taking into account the congestion in the interconnections only, considering copper plate zones, namely all intra-zonal lines as uncongested. However, taking into account the current level of RES (renewable energy sources) penetration and the initiatives of PCR towards a flow-based network modeling, intra-zonal CM should be also monitored.

In the day-ahead market, as implemented in most U.S. ISOs (such as PJM, New York ISO, ISO New England [1,2]), the basic rationale is that the network constraints that are monitored at the real-time market should be monitored at all other (previous) market instances; otherwise, strategic bidding may be engaged by market participants taking advantage of the diverse network representations accounted at different market instances, which may lead to different market prices and significant arbitrage opportunities. In most U.S. markets, a Security Constrained Unit Commitment (SCUC) is initially performed, incorporating DC power flow equations and security constraints. The SCUC is followed by a Security Constrained Economic Dispatch (SCED), with the full DC network representation along with linear $N-1$ security constraints (for a critical contingency set) to account for the system security. After an iterative procedure resolving all possible congestions and $N-1$ security issues, an AC power flow is solved to determine the final area interchange values. This SCED procedure defines the day-ahead Locational Marginal Prices (LMPs) that will be finally applied in the day-ahead settlement for generation and demand, as a function of (a) the energy price, (b) congestion price and (c) marginal or average losses price. Since European markets use DC power flow equations (e.g. linearized PTDFs) to account for congestion management in the intra-zonal and inter-zonal transmission lines, the first two components are also inherently included in the Market Clearing Prices in the European market, but the third component (marginal loss price) is absent.

SCUC is widely used for the efficient system operation in the U.S. deregulated energy markets [3,4]. Since SCUC constitutes a non-convex, non-linear, large-scale, mixed-integer optimization problem, several algorithms have been employed in the literature

* Corresponding author. Fax: +30 2310 994352.
E-mail address: pbiskas@auth.gr (P.N. Biskas).

http://dx.doi.org/10.1016/j.epsr.2016.07.017
0378-7796/

Nomenclature

Indices and Sets

$t \in T$ Index (set) of trading periods in the trading day (typically, the trading period is one hour)
$n \in N$ Index (set) of nodes; especially, for the system reference node, the symbol *ref* is used
$n' \in N_n$ Index (set) of nodes connected to node n
$l \in L$ Index (set) of transmission lines
$s \in S_n$ Index (set) of simple supply/demand hourly priced energy orders (offers/bids) submitted at node n
$b \in B_n$ Index (set) of block orders submitted at node n, where b includes supply block offers and demand block bids; $B_n \subseteq B$
$lb \in LB_n$ Index (set) of linked block orders submitted at node n, $LB_n \subseteq B_n$
$c \in C$ Set of transmission lines checked during the contingency analysis; also used as a set of contingency states studied during contingency analysis

Main Parameters

P_s^t, Q_s^t Price-quantity pair of the hourly priced energy order s in trading period t, in €/MWh and MWh, respectively; Q_s^t is negative for supply offers and positive for demand bids
P_b, Q_b^t Price-quantity pair of block order b, in €/MWh and MWh, respectively; Q_b^t is negative for supply and positive for demand; in case of a profile block order b, the quantity Q_b^t may be different in each trading period t
R_b^{min} Minimum Acceptance Ratio of block order b, in p.u.
A_b^{lb} Linked block order lb to block order b incidence matrix
$D_n^{AC,t}$ Loss distribution factor (computed through an AC Load Flow) of node n for trading period t, in p.u.
$LF_n^{AC,t}$ Loss sensitivity factor (computed through an AC Load Flow) for node n and trading period t, in p.u.
$offset^{AC,t}$ System losses linearization offset (computed through an AC Load Flow) in trading period t, in MWh
$P_{loss}^{AC,t}$ System losses (computed through an AC Load Flow) in trading period t, in MWh
FL_l^t Active power flow limit of line l in trading period t under no contingency, in MWh
$FL_{l,c}^t$ Active power flow limit of line l in trading period t in contingency state c, in MWh
$PTDF_l^{n,ref}$ Power Transfer Distribution Factor (PTDF) of transmission line l for an energy transfer from node n to reference node *ref*, in p.u.
$LODF_{l,c}$ Line Outage Distribution Factor (LODF) related to transmission line l in contingency state c, in p.u.
$P_{fnd,n}^t$ Fictitious nodal demand corresponding to system losses in trading period t in node n, in MWh

Variables

x_s^t Acceptance ratio of supply/demand hourly order s in trading period t
x_b Acceptance ratio of block order b
u_b Clearing status of block order b
$flow_l^t$ Active power flow in line l in trading period t under no contingency, in MWh
$flow_{l,c}^t$ Active power flow in line l in trading period t in contingency state c, in MWh
$p_{n,t}^{inj}$ Net energy injection at node n in trading period t, in MWh
P_{loss}^t System losses in trading period t, in MWh

to obtain an optimal or close-to-optimal solution. The most common solution methodology is to divide the SCUC problem in two components, a Master Problem (MP) taking the unit commitment and dispatch decisions, and one (or more) Sub-Problem(s) (SP) handling the network congestion and security ($N-1$) constraints [5–15]. The Master Problem is usually solved using (a) Mixed Integer Linear Programming (MILP) or (b) Lagrangian Relaxation (LR)/Augmented Lagrangian Relaxation (ALR) methods (decomposing the problem in sub-problems for each generating unit and solving them using e.g. dynamic programming). The SP is formulated either using the full AC power flow equations or the DC network representation. The possible violations found in the SP are usually fed back to the MP as additional constraints using Benders decomposition (BD) or using Linearized (line flow) Sensitivity Factors (LSF) [6]. The MP and the SP are coordinated within an iterative process, which terminates when no more violations exist. An extensive analysis of research works on SCUC is given in Ref. [6]; additionally, the basic features of each research work [6–15] are presented in Table 1.

Nevertheless, the above research works do not discuss pricing issues, which are crucial in the wholesale electricity markets. In the literature, the Locational Marginal Pricing theory was established for nodal markers [16–18], and it was later adopted for the market clearing and congestion management by many markets in the U.S. (PJM, New York ISO, New England ISO, CAISO), in Australia and in New Zealand. The Locational Marginal Prices (LMPs), or nodal prices, are the backbone of the nodal markets and are usually attained by the solution of a Security Constrained Economic Dispatch (SCED) either in the day-ahead market or in the real-time market. However, SCED is non-linear hard, non-convex problem, so LP-based methods have been utilized in the literature to find a faster robust solution. In some works, the system losses have been modeled/approximated within a DCOPF model, leading to more accurate results (with respect to the plain DC system representation) in the LMPs [19–22]. In Ref. [19] a DCOPF-based algorithm is proposed using a fictitious nodal demand (FND) model to offset the system losses; the drawback of this method is the dependency of the LMPs from the reference node. The basic idea behind the computation of the LMPs (their three components) based on a distributed slack-bus formulation is presented in Ref. [20]. In Ref. [21] a new method is proposed to handle system losses in the DC network representation. This method uses nodal loss distribution factors and the attained LMPs are independent of the reference node selection. However, in Ref. [21] these factors are preset and constant and the LMPs have a heavy reliance to these factors; this is handled efficiently in Ref. [22], where an iterative process is presented, during which the loss-related factors (loss factors, loss offset and the loss distribution factors) are updated appropriately, leading to improved accuracy in loss and congestion calculation, and eliminating the reliance on presetting these loss-related factors.

In European markets, a zonal-based pricing scheme is prevalent, thus defining zonal prices (per bidding area) instead of nodal. This stems from the "Network Code on Capacity Allocation and Congestion Management" [23], which explicitly states (Article 46, clause 2) that the developed pan-European price coupling algorithm shall determine "*a single Clearing price for each Bidding Zone and Market*