Electric Power Systems Research 78 (2008) 1764–1772

Contents lists available at ScienceDirect

Electric Power Systems Research

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

Optimal energy exchange of an industrial cogeneration in a day-ahead electricity market

J.M. Yusta [a,*], P.M. De Oliveira-De Jesus [b], H.M. Khodr [c]

[a] Department of Electrical Engineering, University of Zaragoza, Spain
[b] Department of Electrical and Computer Engineering of Faculdade de Engenharia da Universidade do Porto, Portugal
[c] Knowledge Engineering and Decision-Support Research Group of the Electrical Engineering Institute of Porto, Portugal

A R T I C L E I N F O

Article history:
Received 21 February 2007
Received in revised form 3 January 2008
Accepted 9 March 2008
Available online 12 May 2008

Keywords:
Cogeneration
Power generation
Scheduling
Optimization
Liberalized energy markets

A B S T R A C T

This paper addresses an optimal strategy for the daily energy exchange of a 22-MW combined-cycle cogeneration plant of an industrial factory operating in a liberalized electricity market. The optimization problem is formulated as a Mixed-Integer Linear Programming Problem (MILP) that maximizes the profit from energy exchange of the cogeneration, and is subject to the technical constraints and the industrial demand profile. The integer variables are associated with export or import of electricity whereas the real variables relate to the power output of gas and steam turbines, and to the electricity purchased from or sold to the market. The proposal is applied to a real cogeneration plant in Spain where the detailed cost function of the process is obtained. The problem is solved using a large-scale commercial package and the results are discussed and compared with different predefined scheduling strategies.

1. Introduction

Cogeneration is extensively used as a distributed energy source to meet industrial thermal and electrical demand, one of the reasons being that cogeneration schemes offer high energy efficiency. In the last three decades governmental policies have strongly encouraged industries to install cogeneration as a way to obtain global energy savings and reductions in the environmental impact.

Under the scope of the ongoing restructuring process in electricity markets, cogeneration is now considered as a consumer/producer agent entitled to buy or sell electricity according to its needs, which in turn depend on the thermal and electric demands of the industrial process.

Some authors have proposed many ways to solve the optimal dispatch problem of cogeneration systems by minimizing all production costs (fuel, operation, maintenance, etc.) related to electric power and thermal capacity [1–7]. Pioneering contributions were made in the late 80s incorporating power trades between the cogeneration plants and electric distribution utility [8,9] inspired by the spot pricing theory condensed in Ref. [10]. The implementation of spot pricing theory derives from complex price schemes, among other real-time prices (RTP) and time of use prices (TOU) [10,11]. An efficient strategy for energy exchange scheduling in a cogeneration plant is presented in Ref. [12] that considers real-time prices and consequently shifts steam operations.

To assess the impact of TOU prices in cogeneration sizing and operation several optimization procedures have been proposed in the literature and have been classified in Table 1.

In Ref. [13–16] Mixed-Integer Linear Programming (MILP) models have been proposed. Such optimization problems can be appropriately solved with large-scale commercial programming packages. Evolutionary Programming (EP) techniques as well as genetic algorithms (GA) were tested in Ref. [17–21] to tackle the nonlinearities of generation cost function. A Newton-based approach was proposed in Ref. [22] for optimal operation of back pressure cogeneration scheme under TOU rates.

In Ref. [23] a generalized formulation to determine optimal scheduling of a combined-cycle cogeneration unit is discussed, but does not properly consider an energy market structure. The economic benefit of energy exchange of cogenerators with the electric network under pool markets has not been extensively considered, while electricity markets are actually being worldwide operated on this basis.

Under day-ahead (DA) electricity markets the awareness of high or low electricity prices in the following day can encourage to sell or to buy electricity depending on the gas and steam turbines operation and the industrial demand in heat and electricity. The

* Corresponding author. Tel.: +34 976 761922; fax: +34 976 762226.
E-mail address: jmyusta@unizar.es (J.M. Yusta).

0378-7796/$ – see front matter © 2008 Elsevier B.V. All rights reserved.
doi:10.1016/j.epsr.2008.03.012

Table 1
Optimal cogeneration sizing and operation procedure

Type	Decision horizon	Solution technique
MILP	Short-term	Branch and Bound [13–16]
MINLP	Multi-time interval	Evolutionary Programming (EP) [17,18]
	Short-term	Genetic Algorithms (GA) [19,21]
	Short-term	GA and EP [20]
	Short-term	Newton based [22,23]

cogeneration plant can purchase power in several ways: directly from the DA market hour by hour, by a bilateral contract with a generator, or by a contract agreement with a retailer company (flat, two-part, TOU prices, etc.).

Operators of cogeneration systems face a complex problem when considering operating strategies for their facilities. The management of the cogeneration system requires constant evaluation of electrical and thermal load, plant performance variables and the relationship of these variables to energy prices. The operating strategy used must be dynamic and available on an uninterrupted basis to meet the management goal of maximizing the plant's economic return.

This work presents an optimal strategy for the energy exchange program of a cogeneration plant of an industrial factory in Spain entitled to sell power in a DA electricity market and to purchase electricity by a negotiated supply contract with a retailer. The optimization problem is written as a Mixed-Integer Linear Programming Problem maximizing the energy exchange profit of the cogeneration in the short term subject to the technical constraints as well as the industrial demand profile. The problem is solved using a large-scale commercial optimization package and the results are discussed and compared for different predefined scheduling strategies.

2. Combined-cycle cogeneration plant model

A combined-cycle cogeneration requires three basic pieces of equipment: gas turbine, waste heat recovery boiler and steam turbine. Figs. 1 and 3 show respectively the basic and detailed configurations. The cogeneration cost functions for gas turbine, steam turbine and waste heat recovery boiler are presented in the following.

2.1. Gas and steam turbines cost model

In a combined-cycle cogeneration scheme, the gas turbine cost function [23] is given by the following expression:

$$C_{\mathrm{GT}h} = f \cdot M_{\mathrm{GT}h} + C_{\mathrm{GTM}} \quad (1)$$

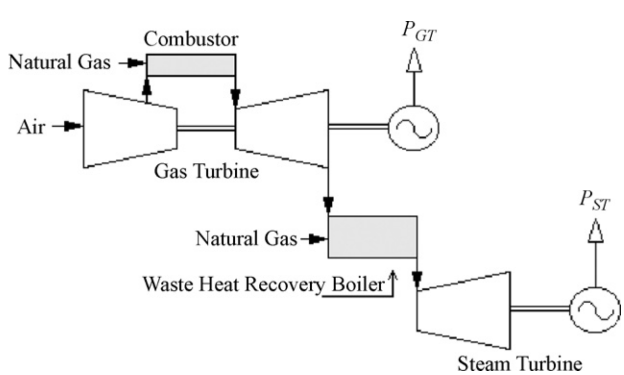

Fig. 1. Combined-cycle cogeneration basic configuration.

The mass flow rate of the fuel input $M_{\mathrm{GT}h}$ as a function of gas turbine power output $P_{\mathrm{GT}h}$ (in MW) is given by the following quadratic function:

$$M_{\mathrm{GT}h} = aP_{\mathrm{GT}h}^2 + bP_{\mathrm{GT}h} + c \quad (2)$$

where a, b and c are the coefficients of the equipment provided by the gas turbine manufacturer.

The steam turbine cost per hour is only given by the maintenance cost $C_{\mathrm{ST}h} = C_{\mathrm{STM}}$.

2.2. Waste heat recovery boiler model (WHRB)

The operating cost of the waste heat recovery boiler is related to the exhaust of gas turbines and the additional natural gas if required [23].

$$C_{\mathrm{W}h} = \left(M_{4h} \frac{H_4 - H_{10}}{\eta_{\mathrm{W}}} - \mathrm{MF}_h \cdot C_{\mathrm{p}} \cdot \Delta T \right) \frac{f}{C_{\mathrm{vf}}\rho} + C_{\mathrm{WM}} \quad (3)$$

The exhaust gas flow rate MF_h as a function of gas turbine power output $P_{\mathrm{GT}h}$ at hour h is given by

$$\mathrm{MF}_h = \phi + \gamma P_{\mathrm{GT}h} \quad (4)$$

where ϕ (kg/h) and γ (kg/MWh) are specified values.

The output mass flow rate of steam M_{4h} (kg/h) as function of steam power output $P_{\mathrm{ST}h}$ at hour h is given by:

$$M_{4h} = \sigma P_{\mathrm{ST}h} \quad (5)$$

where σ (kg/MWh) is a coefficient of the steam turbine.

3. Energy exchange framework

The energy exchange between distributed generators and electricity networks depends on the economic context of the liberalized market and on its regulatory rules. The main characteristics of the Spanish electricity market are presented below.

3.1. Energy imported from the electric network

The cost of imported energy for the industrial factory is given by a supply contract previously negotiated with a retailer that includes the traded energy price plus energy and capacity network access tariffs. These access tariffs are regulated and have two components, one depends on the energy actually supplied in a given hour and another on the power contracted. The network access tariffs are distributed in six periods and applied throughout the year taking into account the month and the type of day [24], as shown in Fig. 2.

The cost of imported electricity $P_{\mathrm{IMP}h}$ from the grid at given hour is written as:

$$C_{\mathrm{IMP}h} = (\mathrm{Ce}_h + \mathrm{We}_h) \cdot P_{\mathrm{IMP}h} + \mathrm{Wc}_h + C_{\mathrm{EM}} \quad (6)$$

3.2. Energy exported to market

In Spain, cogeneration is regulated under a special regime where all the energy injected to the electric network can be sold to the market [25]. The exported energy is paid at the hourly marginal price ρ_h previously established in the day-ahead electricity market plus an additional fee or premium pr. Price setting for exported energy to the market is prior to the optimization process and regarded as known variables. In this case, the plant is not able to modify the energy prices at the wholesale market. The revenues obtained by energy sold at given hour $P_{\mathrm{EXP}h}$ to the market are:

$$R_{\mathrm{EXP}h} = (\rho_h + \mathrm{pr}) \cdot P_{\mathrm{EXP}h} \quad (7)$$