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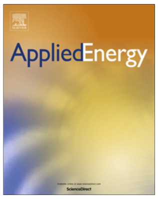

Load forecasting and dispatch optimisation for decentralised co-generation plant with dual energy storage

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HIGHLIGHTS

- Open software components for load prediction and rolling horizon CHP plant optimisation are described.
- Results indicated that solver overheads increased 380-fold during low heat load periods.
- Solving times <1 s were regained by considering differing dispatch and unit commitment horizons.
- 32% cost reductions were observed through balancing market interaction when load prediction inaccuracies were present.
- Results indicated costs were significantly more sensitive to prediction accuracy than plant model accuracy.

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ABSTRACT

Environmental concerns combined with the liberalisation of the energy markets has led to the emergence of small to medium-scale decentralised generation equipment embedded within transmission and distribution networks. Commonly, such plant is operated by small to medium private enterprises and dispatched independently from centralised resources. The liberalisation of energy markets has also brought about the rise of variable wholesale electricity markets, in the form of the spot (day-ahead) market and the balancing (intra-day) markets across the EU and beyond. As such, there is much interest in how decentralised generation equipment can be most profitably operated in this context. This paper focuses on short-term forecasting of both heat and electrical loads, along with unit commitment scheduling and economic dispatch optimisation, for a small/medium scale decentralised combined heat and power (CHP) plant. In the work presented the plant is assumed to be equipped with local heat and electricity storage and operating in the presence of fluctuating wholesale energy prices and local loads. The approach adopted builds on recent research employing Mixed Integer Linear Programming (MILP) models and non-linear boiler efficiency curves, and extends this work into a rolling horizon context. Results are presented which demonstrate the efficiency of the proposed approach and investigate the sensitivity of the results with respect to CHP model accuracy and load prediction accuracy. The results indicated that profit is much more sensitive to the accuracy of load predictions than indicated by previous work in the area. The findings also challenge those of recent work in the field, which suggest that a strategy of interacting with the spot (day-ahead) market only is the most profitable for small/medium scale decentralised energy producers. The results presented in this paper indicate that when load prediction inaccuracies are also considered in the CHP optimisation framework, a strategy interacting with both the spot (day-ahead) market and the balancing (intra-day) market is significantly more profitable than a strategy interacting with the spot market only.

1. Introduction

1.1. Context

Traditionally, for economic and safety reasons, the two most commonly consumed worldwide forms of energy – heat and electricity – have been generated by large fossil-fuelled generators and transported to consumers via one-way transmission and distribution networks (typically through hot water or steam pipe work and copper wires) [1]. Typically generation was distributed over several large generating stations operating in parallel, with transmission interconnections spanning several countries for electrical grids, with these generators and interconnections under the control of a small number of public and private bodies [1,2]. However the liberalisation of the energy markets – combined with

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Nomenclature

Name	Description (units)
Indices	
t	discrete-time step index (h)
i	index of slack variables (–)
j	index of co-efficient in polynomials (–)
k	step-ahead index for predictions (–)
Parameters	
λ	forgetting factor of recursive least-squares identifier (–)
A_B	co-efficient of boiler efficiency function (–)
B_B	co-efficient of boiler efficiency function (–)
C_B	co-efficient of boiler efficiency function (–)
A_E	autoregressive polynomial for electricity demand prediction (–)
B_E	exogenous input polynomial for electricity demand prediction (–)
C_E	moving average polynomial for electricity demand prediction (–)
A_H	autoregressive polynomial for heat demand prediction (–)
B_H	exogenous input polynomial for heat demand prediction (–)
C_H	moving average polynomial for heat demand prediction (–)
ah_j	coefficient j of polynomial A_H (–)
bh_j	coefficient j of polynomial B_H (–)
ch_j	coefficient j of polynomial C_H (–)
ae_j	coefficient j of polynomial A_E (–)
be_j	coefficient j of polynomial B_E (–)
ce_j	coefficient j of polynomial C_E (–)
η_E	electrical efficiency of CHP plant (–)
η_H	thermal efficiency of CHP plant (–)
β_{Max}	maximum heat-to power ratio (–)
β_{Min}	minimum heat-to power ratio (–)
$C_{E\alpha}$	equivalent electrical store holding efficiency (–)
$C_{E\beta}$	equivalent electrical store holding efficiency (–)
C_F	CHP plant unit fuelling cost (€ per unit of fuel/h)
C_{Fmin}	minimum fuelling constraint for CHP plant (€ per unit of fuel/h)
$C_{H\alpha}$	thermal store hourly holding efficiency (–)
$C_{H\beta}$	thermal store conversion efficiency (–)
C_{Off}	cost savings per time step when CHP plant is switched off (€)
C_{SS}	startup/shutdown costs of the CHP plant (€)
C	unit commitment horizon (time steps)
fa_j	coefficient fa of cost function affine segment j (–)
fb_j	coefficient fb of cost function affine segment j (–)
H	dispatch horizon (time steps)
M	prediction model horizon (time steps)
PQ_{Max}	maximum limit of combined power (electrical and thermal) generated by CHP plant (kW)
Variables	
$\beta(t)$	heat-to power ratio at time step t (–)
$\Delta C_E(t)$	charge/discharge power of equivalent electrical energy store at time step t (kW)
$\Delta C_H(t)$	charge/discharge power of thermal energy store at time step t (kW)
$Q(t)$	thermal power generated by CHP plant at time step t (kW)
$C_E(t)$	equivalent amount of electrical energy held in storage at time step t (kW h)
$C_H(t)$	thermal energy held in storage at time step t (kW h)
$C_{HB}(t)$	price for buying thermal energy at time step t (€ per kW h)
$C_{HS}(t)$	price for selling thermal energy at time step t (€ per kW h)
$C_{EB}(t)$	price for buying electrical energy at time step t (€ per kW h)
$C_{ES}(t)$	price for selling electrical energy at time step t (€ per kW h)
$D_E(t)$	measured electrical demand at time step t (kW)
$\widehat{D}_E(t+k\|t)$	k-step ahead prediction of electrical demand made at time step t (kW)
$D_H(t)$	measured thermal demand at time step t (kW)
$\widehat{D}_H(t+k\|t)$	k-step ahead prediction of thermal demand made at time step t (kW)
$e_H(t)$	value of white noise sequence in heat demand prediction model at time step t
$e_E(t)$	value of white noise sequence in electricity demand prediction model at time step t
$I(t)$	plant On/Off indicator variable at time step t (–)
$J(t)$	weighted sum of quadratic electricity and thermal prediction errors up to time step t (–)
$P(t)$	electrical power generated by CHP plant at time step t (kW)
$PQ(t)$	combined power (electrical and thermal) generated by CHP plant at time step t (kW)
$T(t)$	average ambient temperature at time step t (°C)
$\widehat{T}(t+k\|t)$	k-step ahead prediction of ambient temperature made at time step t (°C)
$X_{EB}(t)$	amount of electrical energy bought at time step t (kW h)
$X_{ES}(t)$	amount of electrical energy sold at time step t (kW h)
$X_{HB}(t)$	amount of thermal energy bought at time step t (kW h)
$X_{HS}(t)$	amount of thermal energy sold at time step t (kW h)
$z_i(t)$	slack variable i at time step t (–)
Functions	
$\eta_B(L)$	boiler efficiency (%) at load L (%)
$F(PQ)$	approximate fuelling cost function for combined CHP plant output level PQ

environmental concerns and the need for a low-carbon economy – has forced a rethink in the way that energy is generated and distributed to consumers [2]. In particular, the emergence of small and medium scale generation equipment (typically driven by renewable or alternative forms of energy conversion) embedded within transmission and distribution networks is becoming increasingly commonplace. In addition, technological improvements to Energy Storage Systems (ESSs) are enabling an increase in their use and capacity. ESSs provide an effective means to help supply meet demand with unpredictable daily and seasonal variations, and offers additional energy arbitrage opportunities: buying or generating energy when it is comparatively inexpensive, and reselling it at a later time at a higher price [3,4].

In the above context this paper presents a timely and novel approach to the repetitive cost-optimal balancing of supply with forecasted demand for a decentralised small/medium-scale

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