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Modelling high level system design and unit commitment for a microgrid

A.D. Hawkes [a,*], M.A. Leach [b]

[a] Centre for Energy Policy and Technology, Imperial College London, London SW7 2AZ, UK
[b] Centre for Environmental Strategy, Faculty of Engineering, University of Surrey, Guildford GU2 7XH, UK

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ABSTRACT

This article develops a linear programming cost minimisation model for the high level system design and corresponding unit commitment of generators and storage within a microgrid; a set of energy resources working co-operatively to create a cost effective, reliable and environmentally friendly energy provision system. Previous work in this area is used as a basis for formulation of a new approach to this problem, with particular emphasis on why a microgrid is different to centralised generation or other grid-connected decentralised energy resources. Specifically, the model explicitly defines the amount of time that the microgrid would be expected to operate autonomously, and restricts flow of heat between microgrid participants to defined cases. The model developed is applied to a set of United Kingdom commercial load profiles, under best current estimates of energy prices and technology capital costs, to determine investment attractiveness of the microgrid. Sensitivity analysis of results to variations in energy prices is performed. The results broadly indicate that a microgrid can offer an economic proposition, although it is necessarily slightly more expensive than regular grid-connected decentralised generation. The analysis results have raised important questions regarding a fair method for settlement between microgrid participants, and game theory has been identified as a suitable tool to analyse aspects of this situation.

1. Introduction

Decentralised generation (DG) could play an important role in future energy systems, through economically effective reduction of greenhouse gas emissions from energy supply and possible diversification of primary sources of energy where alternative fuels are utilised. An increase in the amount of energy produced in a decentralised manner is generally seen as a desirable outcome by policy makers within the UK and abroad, as indicated by the recent energy review [1]. There are a wide variety of benefits of DG, relating to each of the three pillars of energy policy; economics, environment, and security. For example, economic benefits have been extolled [2], and environmental and security benefits reported [3]. However, barriers are faced relating to the integration of significant amounts of DG, including market structure, regulatory, technical, and some economic issues.

Microgrids are a specific incarnation of the decentralised generation concept. A microgrid is a set of decentralised energy resources,[1] operating cooperatively to provide a reliable, cheap, and possibly efficient and environmentally friendly method of energy provision [4]. Perhaps the defining characteristic of a microgrid is that it is designed to be able to operate autonomously from the larger national grid; the "macrogrid". When the macrogrid is unable to provide electricity to the consumers within the microgrid, its own generators will be able to cater for the entire energy demand of microgrid consumers. Although a microgrid is typically defined in this sense in terms of electricity demand, an equivalent argument applies to heat demand. Most sites already have onsite heat production facilities (i.e. boilers), but installation of combined heat and power (CHP) links electricity and heat production, thus altering the characteristics of considerations for the economics and environmental impact of heat provision.

The economics and environmental impacts of microgrids have been investigated in only a handful of journal publications (discussed in Section 2). This article builds upon existing work by creating a techno-economic microgrid modelling framework that better reflects the physical situation. It achieves this by explicitly defining the length of time the microgrid operates in "islanded" mode and only allowing heat transfer between sites in explicitly defined cases. It considers a large variety of microgrid generation and storage technologies, and uses a Monte Carlo analysis to consider the impact of inclusion of intermittent sources such as wind power, and examines the sensitivity of results to variations in energy prices (for the UK situation). It draws upon this modelling approach and results to pose important questions regarding how microgrid participants might settle cash flows amongst themselves.

The modelling approach developed adapts the frequently-tackled unit commitment problem (and its extension to high-level system design) in order to apply it to the microgrid situation.

* Corresponding author.
E-mail address: a.hawkes@imperial.ac.uk (A.D. Hawkes).

[1] Decentralised energy resource (DER) is defined as any local resource related to the energy system, including generators, storage, and energy demand itself.

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Nomenclature

C_i	installed capacity of CHP generator i (kW_e)
B_i	installed capacity of boiler i (kW_{th})
E_i	installed capacity of electricity storage unit i (kW_e h)
S_i	installed capacity of thermal energy storage unit i (kW_{th} h)
θ_i	installed capacity of non-dispatchable electricity-only generator i (kW_e)
α_i	cost per kW_e installed for CHP generator i (£/kW_e)
β_i	cost per kW_{th} installed for boiler i (£/kW_{th})
ε_i	cost per kW_e h installed for electricity storage unit i (£/kW_e h)
ς_i	cost per kW_{th} h installed for thermal energy storage unit i (£/kW_{th} h)
ρ_i	cost per kW_e installed for non-dispatchable electricity-only generator i (£/kW_e)
a	annuity factor (subscripts refer to corresponding capital investment)
m	annual maintenance cost (subscripts refer to corresponding plant) (£/year)
n	number of CHP generators
k	number of boiler units
o	number of electricity storage units
p	number of thermal energy storage units
l	number of non-dispatchable electricity-only generators
t	number of time periods considered in the problem
$\omega_{i,j}$	output from non-dispatchable electricity-only generator in time period j (kW_e)
$\psi_{i,j}$	maintenance cost for non-dispatchable electricity-only generator i in time period j (£/kW_e h)
$w_{i,j}$	output of CHP unit i in time period j (kW_e h)
$c_{i,j}$	cost per unit output (fuel and maintenance) for CHP unit i in time period j
$x_{i,j}$	output of boiler unit i in time period j (kW_{th} h)
$b_{i,j}$	cost per unit output (fuel and maintenance) for boiler unit i in time period j
$y_{i,j}$	electricity output from electricity storage in unit i in time period j (kW_e h)
v_i	electricity stored in unit i in time period j (kW_e h)
$e_{i,j}$	cost per unit output (maintenance) for electricity storage unit i in time period j
$z_{i,j}$	thermal energy output from thermal energy storage unit i in time period j (kW_{th} h)
$\zeta_{i,j}$	thermal energy stored in unit i in time period j (kW_{th} h)
$s_{i,j}$	cost per unit output (maintenance) for thermal storage unit i in time period
I_j	electricity imported from the grid in time period j
p_j	price for electricity imported from the grid in time period j
E_j	electricity exported to the grid in time period j
r_j	buyback price for exported electricity in time period j
$P_{\text{microgrid}}(\kappa,\lambda)$	fixed cost for microgrid components, as a function of number of sites and distance between sites (κ,λ, respectively)
$R_{l,i}$	ramp down limit for CHP generator i
$R_{u,i}$	ramp up limit for CHP generator i
$h_{l,i}$	maximum discharge rate for electricity storage unit i
$h_{u,i}$	maximum charge rate for electricity storage unit i
$g_{l,i}$	maximum discharge rate for thermal energy storage unit i
$g_{u,i}$	maximum charge rate for thermal energy storage unit i
L_j	electricity demand for all sites within the microgrid in time period j
Q_i	heat to power ratio for CHP generator i
$\eta_{s,i}$	turnaround efficiency of thermal energy storage unit i
$\eta_{e,i}$	turnaround efficiency of electricity storage unit i
H_j	thermal demand for sites served by corresponding generators/storage in time period j
W_j	weighting for time period j (reflection of number of days of this 'type' per year)
Σ	subscript indicates heat demand for thermally-connected sites only (and corresponding generators)

The problem is formulated as linear programming (LP), with the objective function being (minimisation of) equivalent annual cost (EAC) of meeting a given energy demand. EAC is the total annual cost of electricity, fuel, and maintenance, plus the annualised capital cost of the generating units required, minus any revenue gained from exporting electricity to the grid. A definition of EAC can be found in *The Principles of Corporate Finance* [5]. Once the microgrid cost minimisation problem is defined, it is applied to a specific situation in the UK; a hospital, hotel, and leisure centre's combined demand. Sensitivity analysis is performed by altering energy prices within reasonable bounds and applying the model to each price/demand combination. Whilst the mathematical formulation provides a general description of microgrid economics that could be applied to any situation, the results obtained for the specific demand scenario investigated are only applicable to that scenario, and serve as an example of application of the mathematical model. Finally, results are interpreted to comment on high level control of microgrids, and implications of microgrid-wide optimal control schedules on fair settlement between microgrid participants.

2. Background

Microgrids are an emerging energy delivery model that has the potential to increase the penetration of renewables and distributed energy resources present in the UK energy supply system, and may contribute to the governments low carbon aspirations [6]. A microgrid consists of a set of dispatchable (turbines, reciprocating engines, fuel cells) and/or non-dispatchable generators (wind turbines, PV), electrical and thermal energy storage, a grid connection for import and/or export of electricity, heat and power distribution infrastructure and an energy management system [7]. An example microgrid is displayed in Fig. 1. The defining characteristic of a microgrid is that it is able to operate autonomously in "islanded" mode where there is no electricity exchange with the macrogrid, creating a reliable area of the network with high efficiency and low greenhouse gas emissions per unit of final energy consumed. A microgrid may be split into "zones" whereby the most sensitive loads are separated by a breaker from dispensable loads, creating an environment where reliability becomes a more mainstream product and consumers within the microgrid can therefore choose what exposure to loss of load suits their budget.

From an electricity system point of view, the microgrid is a relatively new concept, differing from conventional energy systems where electricity is typically produced in large centralised power stations and then passed through transmission and distribution networks before arriving at the point of demand. The microgrid is an alternative concept where electricity is produced near the point of demand, allowing for efficient co-production of energy utilising combined heat and power (CHP) and avoidance of some transmission and distribution losses that occur in the conventional centralised generation model. A microgrid is a specific case of the

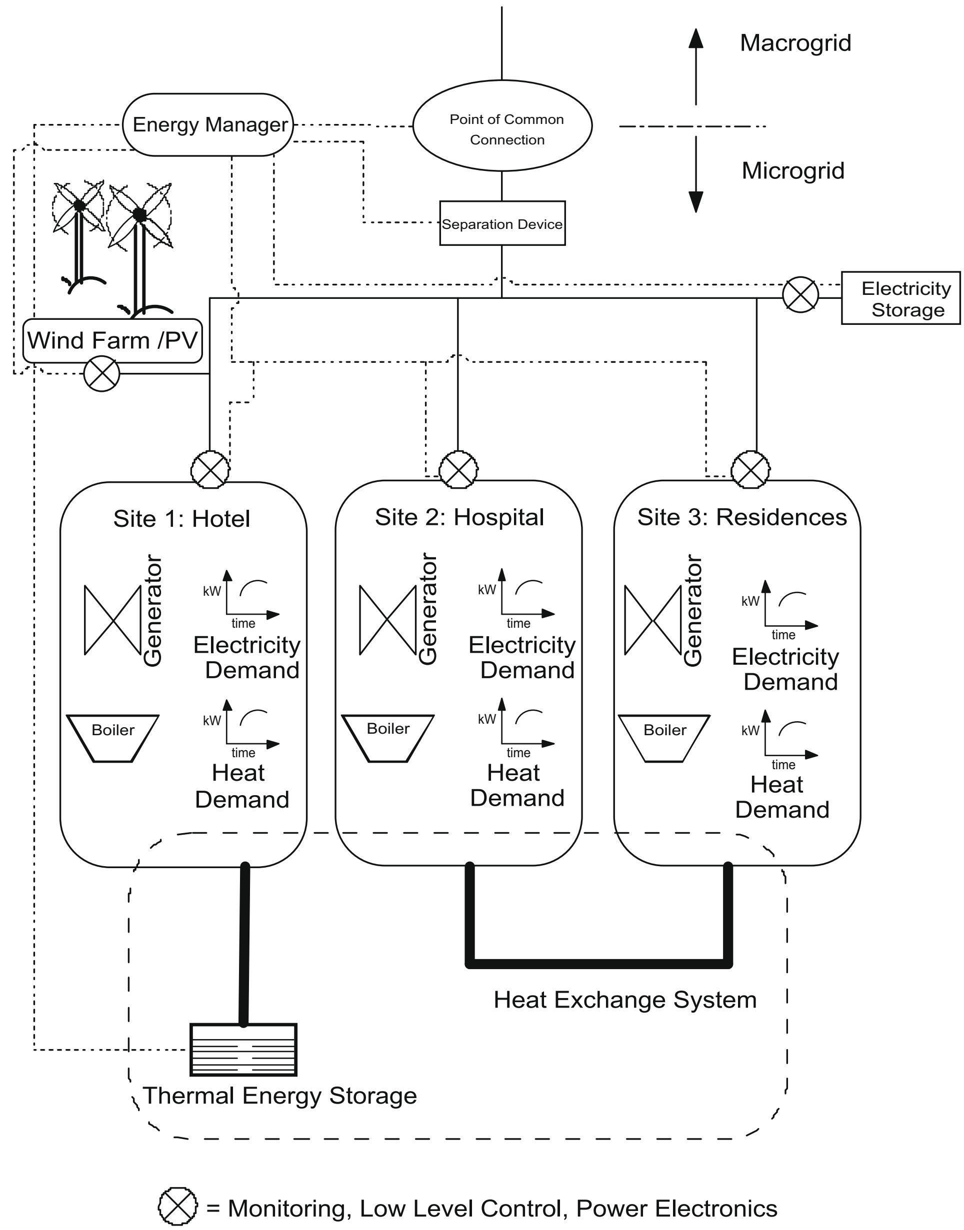

Fig. 1. An example microgrid.

decentralised generation concept in that it is designed to allow a set of decentralised energy resources to function cooperatively to furnish operation in parallel with, or autonomously of, the macro electricity grid. Thus a microgrid is not only more technically demanding than regular decentralised generation from an electrical, electronics and control point of view, but also poses energy economics questions that differ in some important ways from conventional systems.

Another important aspect of microgrids that differs from the conventional centralised model is that active management of resources is required at the distribution level for the microgrid. This is opposed to the passive management of distribution networks that is generally found in centralised systems where electricity flows from large power stations, through the transmission network, and then through distribution network to the customer. If substantial generation occurs at distribution level this mode of energy flow will change, with flow sometimes occurring in the opposite direction. This change poses significant challenges to distribution network operators, particularly in Europe, where systems are not designed to allow these flows. Active control of a microgrid consists of a variety of different considerations, with different timeframes of management. Each generator is controlled in the millisecond–seconds timeframe to provide protection and stability in the network, over minutes to provide constant import or export of electricity as is required in liberalised markets, half-hourly or hourly for aggregate energy flow cost optimisation consideration, and finally on a daily/weekly basis for storage considerations. This article only considers control on the aggregate energy flow and storage timeframes, and readers concerned with electrical engineering issues such as grid interfacing, power quality, and power system control should refer to the literature (for example; [8–13]).

Investigations of microgrid economics are relatively few, with some notable exceptions [14–17]. Zoka et al. [17] formulated the unit commitment and system design problem for a single fuel cell (with electricity storage, and a boiler) microgrid using linear programming, and applied it to a variety of load profiles for the Japanese situation. They found that when power interruption costs were included, a set of commercial entities were better off economically when they install a single microgrid when compared with the case of purchasing energy from a utility or each of them operating independent decentralised energy units. Costa and Matos [15] presented an economic analysis with uncertainty characterisation that specifically included reliability, demonstrating that increased reliability can improve the case for investment in microgrids. Celli et al. [16] used a neural networks formulation to optimise the dispatch of resources, demonstrating that cost savings can be made using the microgrid concept with an intelligent controller. Hernandez-Aramburo and Green [14] compared different modes of power sharing between generators, and then minimised fuel consumption for the microgrid including penalty functions for excess heat production and a 5% security margin to cater for unexpected electricity demand spikes. Only Zoka et al. [17] considered the high level system design problem alongside the unit commitment problem. This paper extends that treatment to impose modified constraints on the system that better reflect the physical situation, and then applies the new formulation to study the case a UK microgrid.

A body of literature exists regarding problems related to microgrid economics: Decentralised generation investment models are common, with well-known incarnations such as HOMER [18] and DER-CAM [19], and a few examples of unit commitment treatment for combined heat and power and systems including wind power are available (for example, [20,21]). Whilst the particular issue of microgrid economics (as opposed to general decentralised generation economics) has not benefited from substantial investigation, one may draw upon this extensive body of related literature, mixing these concepts with the addition of new elements to reflect the microgrid situation. This is the approach adopted in this paper.

3. Mathematical formulation

The unit commitment problem is a frequently visited area of research, where the operational schedule of generators (and other resources) is optimised, usually with the aim of minimising the cost or maximising the profit from meeting electricity demand. The reader is directed to the literature for various treatments of this problem, applying techniques such as dynamic programming, simulated annealing, tabu search, fuzzy computing and genetic algorithms to name a few. The recent literature review of techniques can be found in Padhy [22]. The problem is often tackled from the point of view of analysis of particular technical constraints, such as generator ramp limits, or environmental constraints, such as carbon dioxide emissions targets.

The unit commitment problem can be extended to consider high level system design where broad parameters such as generator capacity, electricity and/or heat storage capacity, and boiler capacity are optimised at the same time as their operational schedule is optimised. This results in a more "optimum" system than the vanilla unit commitment problem because it gives an indication of what generators are best suited to a demand profile and energy price combination, rather than only indicating how best to operate units after they have been purchased/installed. An example of this high level system design optimisation method applied to micro-CHP can be found in Hawkes et al. [23].

This article deals with a deterministic linear formulation of the unit commitment and system design problem as per Zoka et al. [17], but imposes modified constraints on the problem to reflect the chosen definition of a microgrid. Specifically, the amount of time per year that the microgrid is expected to be required to operate in an islanded mode is explicitly modelled, and thermal constraints are stricter in the sense that heat sharing between sites within the microgrid is limited to explicitly defined cases, and heat transfer between seasons (via seasonal storage) is not possible. Islanded operation is explicitly modelled through a combination of weighting day types in the cost function and constraining interaction between the microgrid and the macrogrid on specific days; for example if a microgrid is expected to operate autonomously one day per year, one may place a 1/365 weight on that "day-type" whilst simultaneously constraining (i.e. preventing) import from and export to the macrogrid on that day (see Eq. (11) below). Heat sharing between sites is limited by constructing heat demand constraints that explicitly link particular heat demands with the energy resources that can physically meet those demands. Note that whilst this mathematical formulation is deterministic, uncertainty regarding wind speed is modelled by repeatedly running the deterministic model in a Monte Carlo simulation, with each run relying on a set of wind speeds drawn from a Weibull distribution. This approach accounts for the intermittent nature of wind power (see further discussion of this issue in Section 4).

The objective function of the minimisation is the equivalent annual cost of meeting a given energy (electricity and heat) demand profile. Equivalent annual cost (EAC) is made up of annual electricity, fuel and maintenance cost plus the annualised capital cost of microgrid assets at a chosen discount rate [5]. The formula for EAC is presented in Eq. (1):

$$\begin{aligned}\mathrm{EAC} = {} & \sum_{i=1}^{n}\left(\frac{C_i\alpha_i}{a_c}+m_c\right)+\sum_{i=1}^{k}\left(\frac{B_i\beta_i}{a_b}+m_b\right)+\sum_{i=1}^{o}\left(\frac{E_i\varepsilon_i}{a_e}+m_e\right) \\ & +\sum_{i=1}^{p}\left(\frac{S_i\varsigma_i}{a_s}+m_s\right)+\sum_{i=1}^{l}\left(\frac{\theta_i\rho_i}{a_\theta}+m_\theta\right)+\sum_{i=1}^{l} \\ & \times\sum_{j=1}^{t}\omega_{i,j}\psi_{i,j}W_j+\sum_{i=1}^{n}\sum_{j=1}^{t}w_{i,j}c_{i,j}W_j+\sum_{i=1}^{k}\sum_{j=1}^{t}x_{i,j}b_{i,j}W_j \\ & +\sum_{i=1}^{o}\sum_{j=1}^{t}(y_{i,j}-v_{i,j})e_{i,j}W_j+\sum_{i=1}^{p}\sum_{j=1}^{t}(z_{i,j}-\zeta_{i,j})s_{i,j}W_j \\ & +\sum_{j=1}^{t}I_jp_jW_j+\sum_{j=1}^{t}E_jr_j+P_{\mathrm{microgrid}}(\kappa,\lambda). \end{aligned} \quad (1)$$

The constraints imposed on the optimisation are:

(a) the inability of a unit to exceed its rated capacity,

$$w_{i,j}-C_i \leqslant 0 \quad \text{for } i=1 \text{ to } n \text{ and } j=1 \text{ to } t, \quad (2)$$

$$x_{i,j}-B_i \leqslant 0 \quad \text{for } i=1 \text{ to } m \text{ and } j=1 \text{ to } t, \quad (3)$$

$$\sum_{1}^{j}(y_{i,j}-v_{i,j}) \leqslant E_i \quad \text{for } i=1 \text{ to } o \text{ and } j=1 \text{ to } t, \quad (4)$$

$$\sum_{1}^{j}(z_{i,j}-\zeta_{i,j}) \leqslant S_i \quad \text{for } i=1 \text{ to } p \text{ and } j=1 \text{ to } t, \quad (5)$$

(b) ramp limits for each generator, and charge/discharge rate limits for each storage unit

$$R_{l,i} \leqslant w_{i,j+1}-w_{i,j} \leqslant R_{u,i} \quad \text{for } i=1 \text{ to } n \text{ and } j=1 \text{ to } t, \quad (6)$$

$$y_{i,j} \leqslant h_{u,i} \quad \text{for } i=1 \text{ to } o \text{ and } j=1 \text{ to } t, \quad (7)$$

$$v_{i,j} \leqslant h_{l,i} \quad \text{for } i=1 \text{ to } o \text{ and } j=1 \text{ to } t, \quad (8)$$

$$z_{i,j} \leqslant g_{u,i} \quad \text{for } i=1 \text{ to } p \text{ and } j=1 \text{ to } t, \quad (9)$$

$$\zeta_{i,j} \leqslant g_{l,i} \quad \text{for } i=1 \text{ to } p \text{ and } j=1 \text{ to } t, \quad (10)$$

(c) onsite electricity demand must be met exactly (but import and export of electricity from/to the macrogrid is possible except when the microgrid is islanded),

$$\sum_{i=1}^{n}w_{i,j}+\sum_{i=1}^{l}\omega_{i,j}+\sum_{i=1}^{o}y_i\eta_{e,i}-\sum_{i=1}^{o}v_{i,j}\eta_{e,i}+I_j-E_j=L_j \quad \text{for } j=1 \text{ to } t, \quad (11)$$

$I_j = E_j = 0$ for all j where microgrid is islanded;

(d) heat demand must be met or exceeded and heat transfer between sites within the microgrid is not possible except where defined.

$$\sum_{i=1}^{n} w_{i,j}Q_i + \sum_{i=1}^{k} x_{i,j} + \sum_{i=1}^{p} z_{i,j}\eta_{s,i} - \sum_{i=1}^{p} \zeta_{i,j}\eta_{s,i} = H_{j,\Sigma} \quad \text{for } j = 1 \text{ to } t, \tag{12}$$

(e) electrical or thermal energy stored in one season may not be transferred to another season.

$$\sum_{j=1}^{24}(y_{i,j} - v_{i,j}) = 0 \quad \text{for each unit } i = 1 \text{ to } o, \text{ for each day}, \tag{13}$$

$$\sum_{i=1}^{24}(z_{i,j} - \zeta_{i,j}) = 0 \quad \text{for each unit } i = 1 \text{ to } p, \text{ for each day}. \tag{14}$$

This mathematical formulation of the system design and unit commitment problem is implemented in MATLAB, using the "linprog" function. Monte Carlo simulations are achieved by running this optimisation repeatedly, with each set of input parameters being drawn from a relevant probability distribution.

4. Analysis method and input parameters

4.1. Analysis method

The aim of the application of the model developed above is to investigate system design and dispatch for a specific microgrid in the UK. As a microgrid may consist of a large variety of energy resources and configurations, the number of combinations considered is limited to a manageable set. Therefore this analysis does not represent a final and complete picture of microgrid economics, environmental impact, design or operation for the UK. Rather it highlights the current situation for an interesting and relevant specific case.

Physically, the microgrid considered in this study consists of the following components;

- Up to three CHP generators;
- Wind turbines up to 600 kWe;
- Photovoltaic arrays;
- Up to one boiler per site;
- Electricity storage (e.g. a lead–acid battery);
- Thermal energy storage;
- A grid connection (allowing import and export of electricity when operating parallel to the grid);
- An energy management system;
- A separation device at the point of common connection with the macrogrid;
- Local controllers for each energy resource;
- Conductors;
- Thermal exchange system in defined cases to allow heat sharing between particular sites;
- Communications system.

Other potential energy resources that could be used in a microgrid are not considered in this study, even though they may result in a better economic or environmental outcome. Perhaps the most important resource not considered here is that of load, as load shifting or load reduction can be a valuable tool to reduce costs and environmental impact, particularly in the case of the microgrid, where peak demand when operating autonomously from the "macrogrid" has a profound influence on economics.

Central estimates of current UK energy prices and generator/unit capital costs and maintenance costs are input to the model, and optimal capacity of each generator/unit chosen along with corresponding optimal unit commitment schedule as per Section 3. As wind turbines are a possible microgrid component, and this technology has an intermittent electricity output, it is assumed that wind power cannot contribute to meeting electricity demand on days when the microgrid is operating in islanded mode.[2] This effectively reduces the capacity credit of the wind turbine to near-zero within the microgrid, which is a conservative estimate of its contribution. Additionally, the intermittency of wind power also necessitates a stochastic approach to the problem, where system capacities (CHP, wind, PV, etc.) are optimised one thousand times based on draws from a Weibul distribution (for wind speeds) to arrive at a distribution of system configurations with a corresponding distribution of economic and environmental results.

The final step in the analysis is to perform sensitivity analysis to the "central estimate" result by altering energy prices. Two cases are considered; one where the spark spread is narrowed by increasing the gas price, and one where the spark spread is widened by increasing the electricity price. The stochastic approach described above is then used applied again to each price scenario.

4.2. Input data

A microgrid potentially consists of a large number of energy resources of different types, capital costs, operating costs, etc. It is necessary to limit the number of units considered by the optimiser to furnish tractability of the problem. Three different combined heat and power (CHP) generators are considered with different capital costs and efficiencies, wind turbines and photovoltaic cells (PV), and electrical and thermal energy storage are also potential candidates for use in the microgrid energy resource mix. The basic characteristics and capital costs of each of these candidate technologies are described in Table 1.

Operating expenditure is dominated by fuel and electricity costs. The central estimate of energy tariffs used in this study was sourced from the Department of Trade and Industry Quarterly Energy Prices [24] and is presented in Table 2.

As aggregate electricity consumption of this microgrid generally falls into a category between "large domestic" and "small industrial" and aggregate gas consumption is close to that of "small industrial", central price estimates of 7.0 pence/kWh and 2.7 pence/kWh for electricity and gas, respectively, were used. Electricity export rate, where the microgrid sells electricity back to a supplier, is 4 pence/kWh based on recent average UK wholesale prices. In reality, the energy tariff assigned to the microgrid would differ from these estimates, and would almost certainly be in a half-hourly time-of-use format rather than single average values. However, for the purposes of simplicity and to provide a non-supplier-specific picture of microgrid economics, an average single rate tariff is an acceptable proxy.

Maintenance is also an operating cost, and is presented for each generator in Table 1, based on Firestone [25].

Three physical locations are considered in this analysis; a hospital, a hotel, and a leisure centre. Heat exchange between these physical locations is limited: any heat generation at "site 1" (the hospital) may not be transferred to "site 2" (the hotel and leisure centre). However, electricity may be exchanged between site 1 and site 2. Electricity and thermal demand profiles were taken from CHP Sizer Version 2 Software [26]. Basic statistics of investigated the aggregate demand profile are displayed in Table 3.

[2] Wind power may not contribute to meeting demand on islanded days because this is likely to lead to an erroneous result. Microgrid economics is strongly dependent on the peak demand on islanded days, and it is assumed that wind power cannot contribute to this peak demand, because this contribution is uncertain. This assumption will produce a conservative result.

Table 1
Basic technical parameters and costs of microgrid candidate technologies

Technology	Turnkey cost (£/kW)	Maintenance cost (£/kW h)	Electrical efficiency (LHV)	Overall efficiency (LHV)	Heat-to-power ratio	Lifetime (years)
CHP 1	800	0.01	35%	80%	1.29	15
CHP 2	700	0.01	30%	80%	1.67	15
CHP 3	650	0.01	25%	80%	2.2	15
Boiler	40	0.005	–	80%	–	15
			Cut in windspeed (m/s)	Nominal windspeed (m/s)	Cut out windspeed	
Wind	750	0.005	5	12	25	20
PV	3000	0.005	–	–	–	25
			Turnaround efficiency			
Electricity storage	350	0.005	75%	–	–	5
Thermal energy storage	20	0.001	90%	–	–	25

Table 2
Energy Tariffs for the Microgrid

Energy Source	DTI Category	Tariff rate (pence/ kWh)
Gas	Large domestic inc tax	1.95
Gas	Small industrial inc tax	2.73
Gas	Medium industrial inc tax	2.37
Electricity	Large domestic inc tax	7.73
Electricity	Small industrial inc tax	6.29

Table 3
Statistics of investigated energy demand profile

	Annual electricity demand (GWh)	Annual heat demand (GWh)	Peak electricity demand (kW)	Peak heat demand Site 1 (kW)	Peak heat demand Site 2 (kW)
Hotel, Hospital and Leisure Centre	5896	10,191	868	1137	1006

The demand profiles consists of 12 days of hourly data (6 weekdays and 6 weekend days), spread across seasons (1 weekday and 1 weekend day taken from every second month). Example summer and winter day heat demand profiles for the Hospital (Site 1) and Hotel/Leisure Centre (Site 2) are displayed in Fig. 2.

Following [14, 21], we define a security margin as a proxy for reliability of the microgrid. The peak electricity demand must be exceeded by installed generation capacity within the microgrid by 10%. Similarly, peak heat demand must be exceeded by installed heat generation capacity by 10%.

5. Results and discussion

5.1. Overall economic and environmental result

The vital statistics of Monte Carlo results are presented in Table 4. In all three price scenarios investigated, the microgrid was a sound investment, achieving an average equivalent annual cost (EAC) less than the baseline scenario where energy needs were met via the macrogrid/boiler baseline option. Under the "central

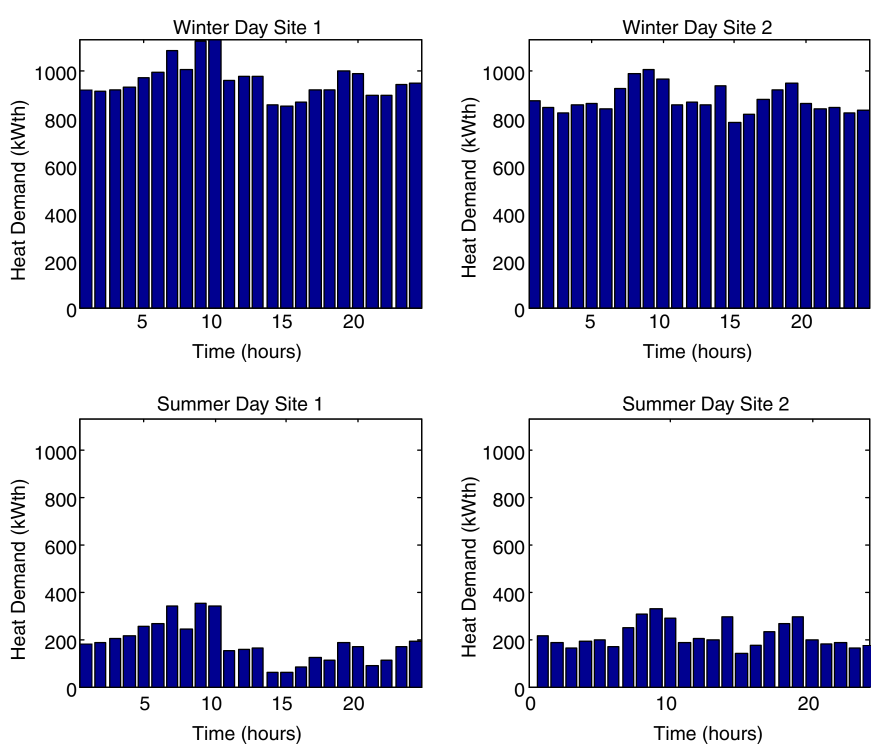

Fig. 2. Heat load profiles for winter and summer days for hospital (Site 1) and hotel and leisure centre (Site 2).

Table 4
Statistics of Monte Carlo results for central estimate prices and sensitivity analysis, for baseline (grid–boiler), conventional decentralised energy resources (DER), and a microgrid

Case	EAC saving vs. baseline (£/year)	Payback period (years)	Emissions reduction vs. baseline (% CO_2)	Average CHP 1 optimum capacity (kW_e)	Average CHP 2 optimum capacity (kW_e)	Average CHP 3 optimum capacity (kW_e)	Average optimum boiler 1 capacity (kW_{th})	Average Optimum Boiler 2 Capacity (kW_{th})	Average Optimum Thermal Energy Storage Capacity ($kW_{th}h$)	Average Optimum Wind Power Capacity (kW_e)
Central estimate baseline	770,000	–	–	–	–	–	1251	1106	–	–
Central estimate DER	682,000	6.1	29%	254	168	221	924	237	231	555
Central estimate microgrid	696,000	7.4	34%	521	183	254	817	233	141	503
+40% gas price baseline	908,000	–	–	–	–	–	1251	1106	–	–
+40% gas price DER	865,000	8.5	23%	148	126	133	1060	534	87	592
+40% gas price microgrid	896,000	14.1	28%	374	193	388	899	63	86	569
+40% electricity price baseline	936,000	–	–	–	–	–	1251	1106	–	–
+40% electricity price DER	669,000	3.5	35%	570	283	127	518	246	518	597
+40% electricity price microgrid	673,000	3.5	35%	556	257	146	778	341	169	599

estimate" of fuel prices, microgrid equivalent annual cost was reduced by approximately 10% relative to the baseline scenario. For the high electricity price and high gas price scenarios, EAC was on average reduced by 28% and 1%, respectively. Carbon dioxide emissions on average decreased by 34% for the central estimate, 28% for the high electricity price scenarios and 35% for the high gas price scenario, indicating the microgrid is likely to produce a positive environmental result in terms of global warming.

However, the fact that the microgrid is a sound investment and offers environmental benefit does not imply that an alternative solution does not offer an even better opportunity. The case of decentralised energy resources (DER) serving the load in parallel with the macrogrid without the capability to act as a microgrid provides a better economic outcome than the microgrid in all cases, although this is accompanied by a less impressive greenhouse gas emissions reduction outcome. The high gas price case exhibits the most significant difference between the microgrid and DER cases, with average payback period doubling, and approximately 10% of Monte Carlo results falling above the cost of the grid/boiler baseline (i.e. in 10% of wind speed cases, investment in the microgrid was not justified). The high electricity price scenario exhibits the smallest difference between microgrid and DER cases, with the additional cost associated with operation as a microgrid opposed to conventional DER approaching zero.

Table 4 shows statistics for these and other important result parameters of the optimised microgrid after the Monte Carlo simulation. The results presented in Table 4 do not represent an estimate of the optimum design for this Microgrid (only the statistics of the results from Monte Carlo analysis are presented). Optimum design requires minimisation of the expectation of EAC, whereas these results present the average of EAC results from this deterministic optimisation formulation.

5.2. Microgrid design

It is of interest to determine how important microgrid design is in terms economic and environmental outcome. If choice of CHP and other plant capacities significantly influences the economic result under uncertain wind speeds and uncertain energy prices, more effort may be made to hedge these risks through well-considered choice of capacities, or through use of conventional financial instruments (e.g. insurance, non-firm forward contracts, etc). A simple measure of the risk inherent in this microgrid is the spread of EAC results for the Monte Carlo simulation, and the spread of EAC results between the three price scenarios. Fig. 3 shows the distribution of EAC for each of the three price scenarios. The distribution of EAC values within each price scenario is approximately ±£250,000 per year around the mean. Therefore whilst variation in wind speed is important, it does not significantly alter the investment decision. This is because in only one of the price scenarios did variation in wind speed result in a microgrid EAC that was larger than the corresponding baseline EAC, and that result has low probability. The spread of results between the price scenarios is more pronounced than the spread of results due to variation in wind speed. Therefore, in terms of total cost of energy provision (i.e. EAC), the modelled variation in fuel and electricity price is more important the variation in wind speed at the site.

The average optimum capacities of the considered generation components are presented in Table 4. Note that PV systems were never selected by the optimisation model, because their high capital cost means they are not competitive with the other technology options considered. Electricity storage (i.e. a lead–acid battery) was also never selected by the optimisation model; in all cases additional CHP capacity was favoured over electricity storage capacity. It is important to note that these results are sensitive to reward afforded to renewable electricity generation; in this study it has been assumed renewable electricity attracts no special treatment. Should renewable generation attract significant reward, it would be expected that PV and/or wind generators combined with electricity storage would offer more attractive economics.

A microgrid designer may be interested in choosing capacities of each CHP unit. In Fig. 4, variation in optimum combined heat and power capacity under varying wind speeds and the three price scenarios for CHP unit 1 (Site 1) is displayed. The high gas price scenario shows the widest variation in optimum CHP 1 capacity with the majority of values between 275 kW_e and 500 kW_e (more than 200 kW_e range), whilst both of the other price scenarios exhibited a range of approximately 50 kW_e. Similarly, in Fig. 5, where variation in optimum CHP capacity for unit 3 is displayed, it is apparent that capacity of this CHP unit is more sensitive in the high gas price (small spark spread) scenario. Choosing the "best" capacities for each CHP unit therefore becomes complicated, because there is significant difference between optimum capacities between price scenarios (see statistics of results in Table 4), and

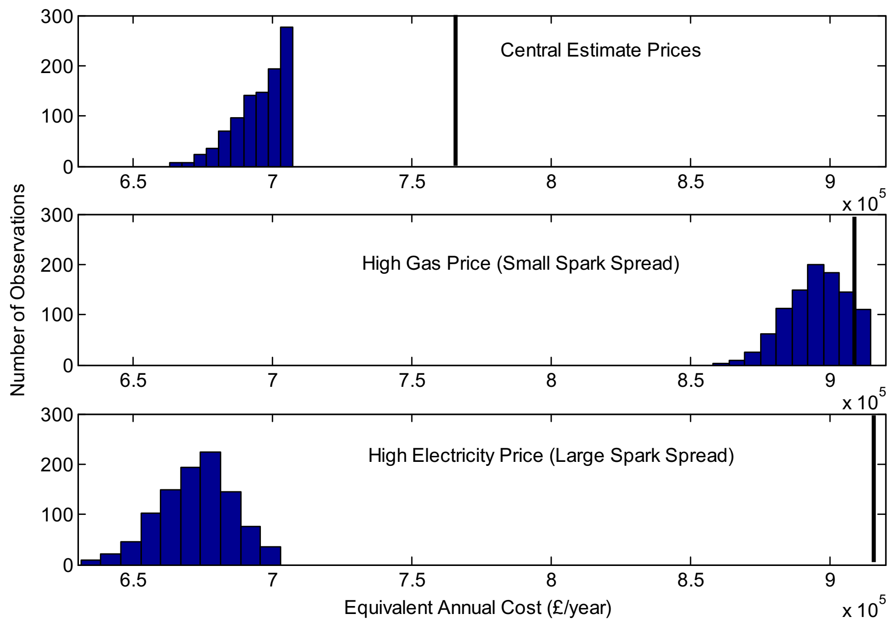

Fig. 3. Histogram of equivalent annual cost for the three price scenarios (vertical line at baseline grid/boiler EAC).

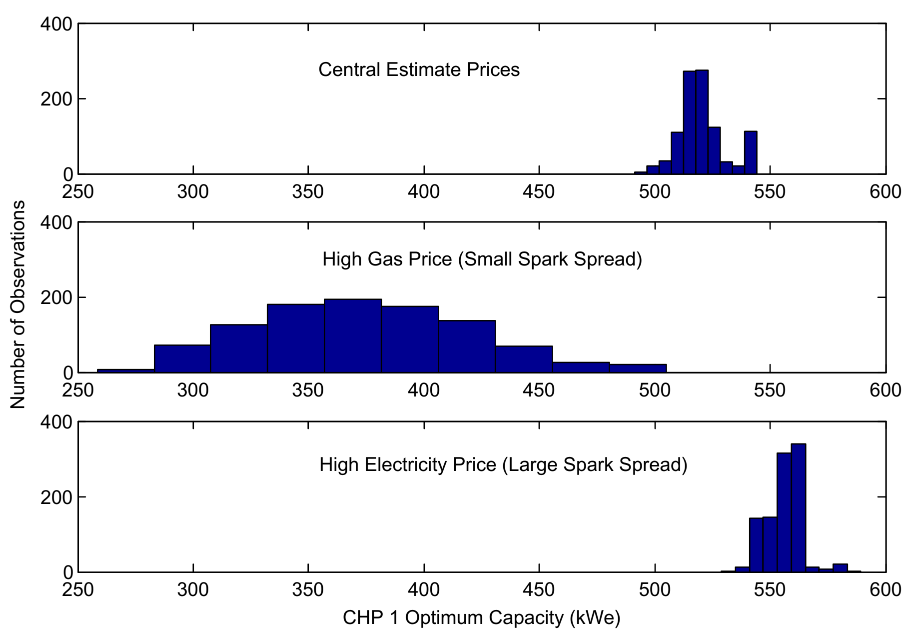

Fig. 4. Histogram of CHP 1 optimum capacity for the three price scenarios.

even within price scenarios (due to variation in wind speed). Presentation of a defensible method for choosing plant capacities given the observed variation is beyond the scope of the article, but requires minimisation of the expectation of EAC, rather than computation of the expected minimum EAC as presented in Table 4.

5.3. Microgrid operation and control

Given the large number of generation sources and the presence of thermal energy storage in the considered microgrid, and the modelled thermal constraints (heat transfer between site 1 and site 2 is not possible), it is of interest to consider the mode of operation of the microgrid. Optimal dispatch patterns of generators when the system is islanded and when it is grid-connected are both of interest.

Firstly, operation of the microgrid when grid-connected is considered. Exchange of electrical energy with the macrogrid is possible. As heat dump is also possible from the system, the generators may operate at any set-point, determined by whatever combination results in minimum cost to the consumers in the microgrid. Heat demand/supply match is displayed in Figs. 6 and 7 for Sites 1 and 2, respectively. An example electricity demand/supply pattern for the grid connected microgrid on a winter day is displayed in Fig. 8. The operational pattern is simple in this grid connected case; to meet heat demand the CHP unit is dispatched first (most efficient unit first in Site 2, which has two units available), and then any supplementary heat required is provided by the boiler. The electricity demand profile is essentially ignored, with any excess production over the demand being spilled to the grid, including any contribution from the wind turbines.

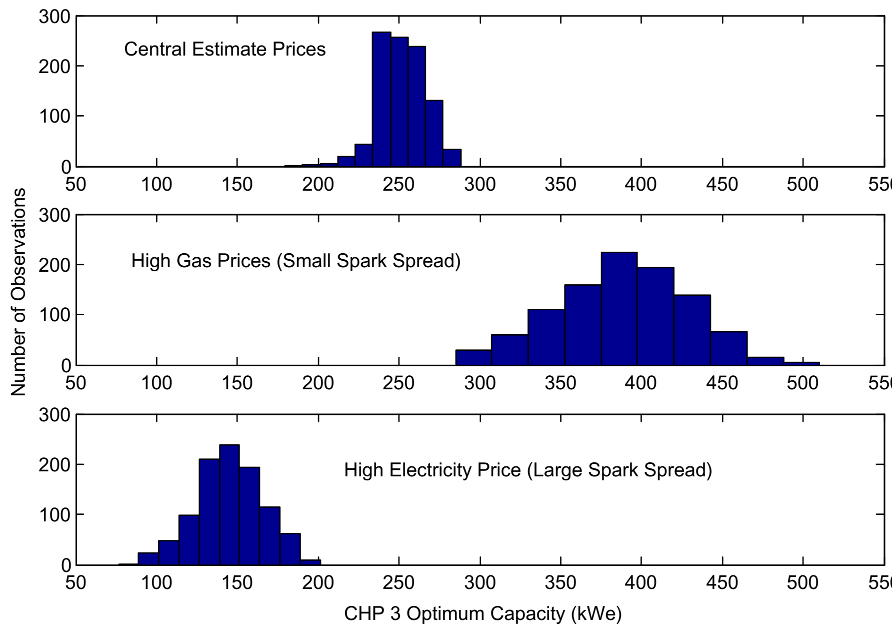

Fig. 5. Histogram of CHP 3 optimum capacity for the three price scenarios.

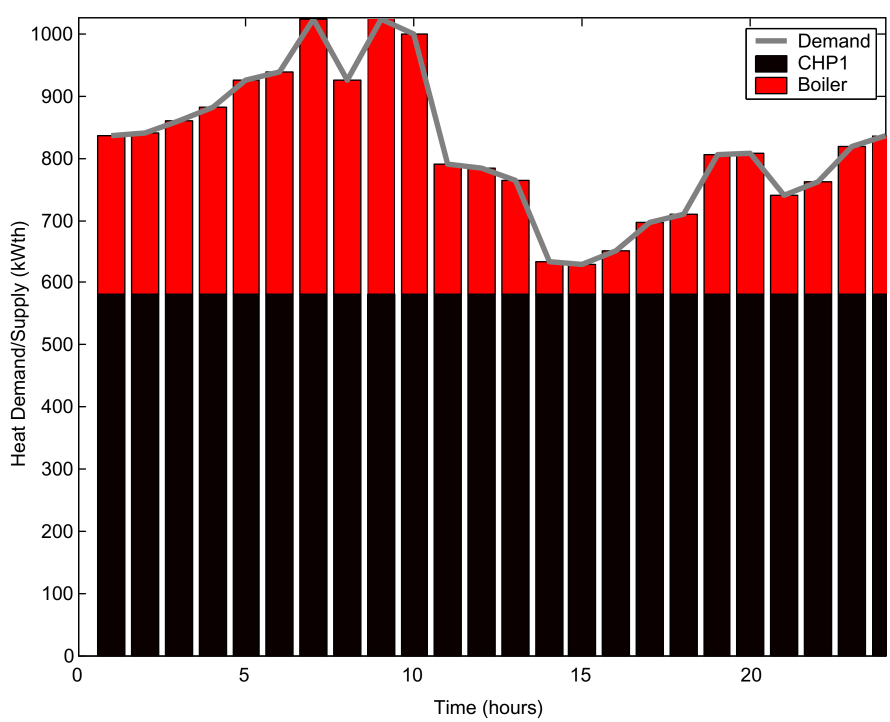

Fig. 6. Site 1. Heat demand and supply balance for a winter day whilst grid connected.

The optimal operational pattern for the islanded case is more complicated than that of the grid connected case. Figs. 9 and 10 show the demand/supply balance for heat for Sites 1 and 2, respectively, and Fig. 11 shows the islanded demand/supply balance for electricity in the microgrid. The microgrid system is much more constrained in the islanded case because electricity demand must be met exactly. Subsequently the operational pattern has changed significantly, and the most efficient CHP unit is no longer dispatched first. Rather the three available units are mixed-and-matched to find an optimal combination of set-points that best matches the heat-to-power ratio of demand given the thermal constraints discussed above.

The operation and control results generated by this optimisation approach form the primary output of relevance to engineering application in this article. It suggests that centrally-coordinated control of microgrid resources may give the best economic and environmental result. This creates an engineering challenge to provide such control systems whilst maintaining reliability and enabling fair settlement between microgrid participants, as discussed below.

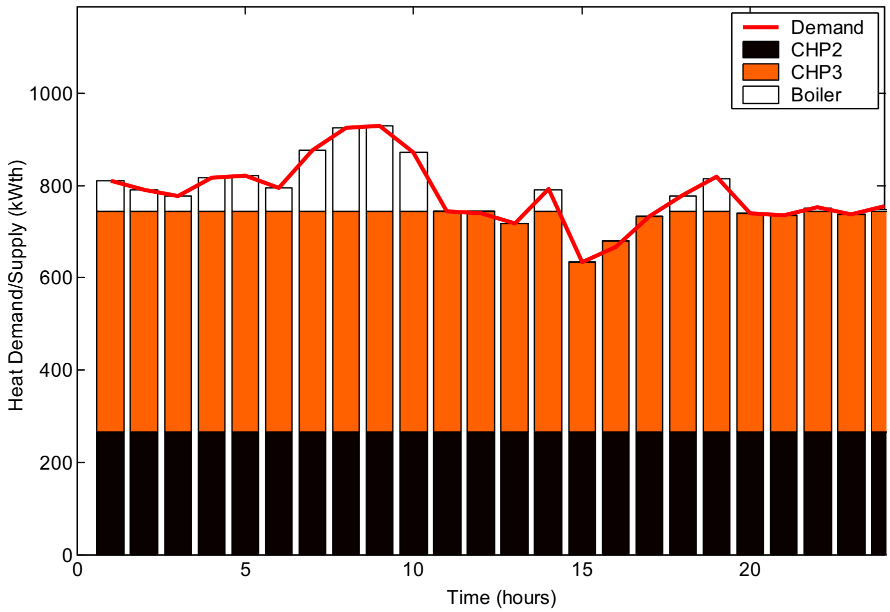

Fig. 7. Site 2. Heat demand and supply balance for a winter day.

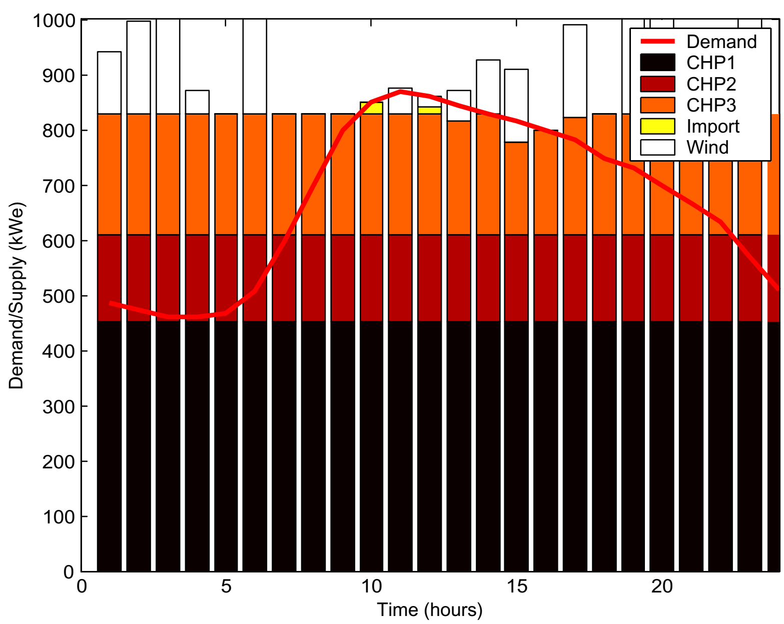

Fig. 8. Microgrid electricity demand and supply balance (grid-connected) for a winter day.

5.4. Settlement and reconciliation for generator aggregations

The discussion above regarding microgrid design and operation raises important questions regarding models of ownership and related cash flows within the microgrid. Whilst the market model for the macrogrid is reasonably well established, the market model within the microgrid is an open area of research. Pertinent questions relate to the interaction between generators in the microgrid, and subsequent impact on fair cash flows to and from actors in the microgrid. For example, the optimisation above considers the whole microgrid, and minimises aggregate cost for all microgrid participants, rather than each participant separately. If optimisation were carried out for one single participant, it may be possible to reduce their cost of energy provision (but consequently increase another participants costs), creating a tension between cooperation and self interest for the participants.

There is an analogy with game theory in this situation. The classic example of game theory known as Prisoner's dilemma creates a situation where each party has a motivation towards self interest, but co-operation leads to the best aggregate result. Where a game is played a single time and participants have little or no knowledge of attitudes of other participants, there is often a tendency towards self-interest. However, if a game is played repeatedly, co-operative strategies often emerge as the best for all participants, where participants exhibiting self-interest can be punished by other participants, leading to loss of utility. Detailed application of game theory to the microgrid or decentralised energy situation is beyond the scope of this paper, but it is clear that behaviour (and settlement)

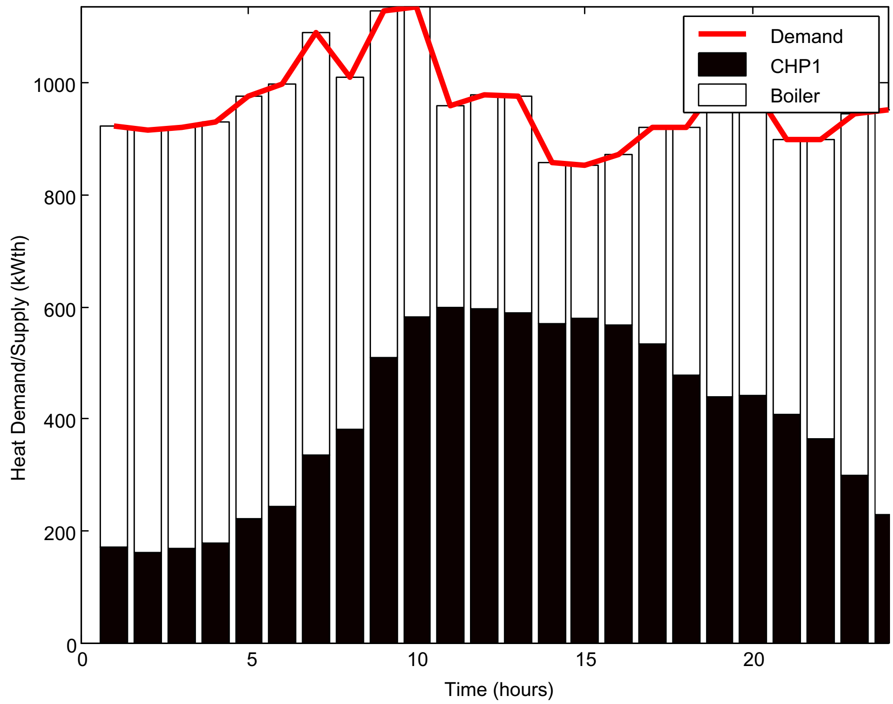

Fig. 9. Site 1. Heat demand and supply balance for a winter day whilst islanded.

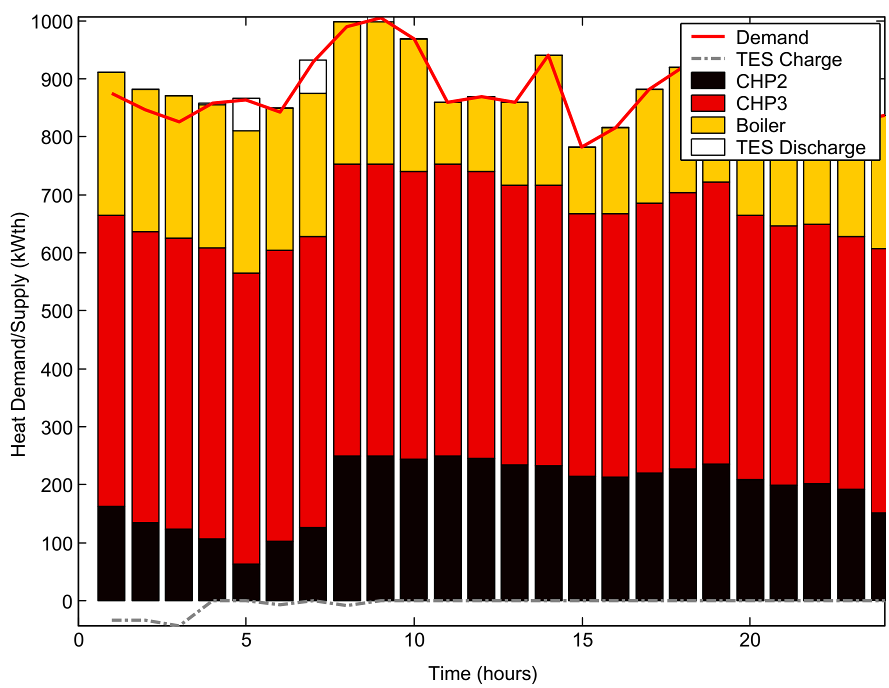

Fig. 10. Site 2. Heat demand and supply balance for a winter day whilst islanded.

amongst participants could be cast as a problem in game theory, with each participant having either self-interest or co-operative attitude.

Taking the example of the islanded microgrid presented in Figs. 9–11 above, it is apparent that Site 1 (i.e. the Hospital) has curtailed its output in order to allow CHP 2 and CHP 3 to generate and provide heat at Site 2 (i.e. the Hotel and Leisure Centre). If Site 1 were considered alone, a better economic outcome could have been achieved by allowing CHP 1 to follow the electrical load of Site 1, thus producing more heat from CHP 1. However, this would have implied Site 2 would need to curtail output from its CHP generators in order to match aggregate electricity demand within the microgrid, resulting in an increase in cost. Therefore Site 1 has increased its costs in order to minimise the costs of the microgrid as a whole.

A possible solution to this problem is development of settlement and reconciliation processes that adequately reward each participant's relative contribution to the aggregate gain that operating in a microgrid configuration provides. This requires calculation of the cost to each participant when they are acting with

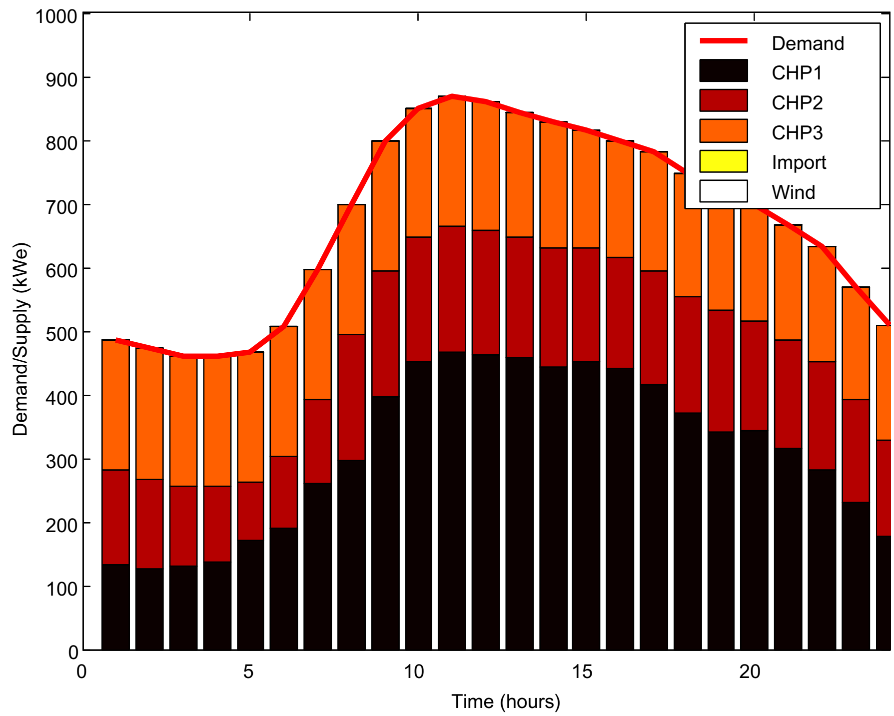

Fig. 11. Microgrid electricity demand and supply balance (islanded) for a winter day.

complete self interest and ensuring their received costs do not, on average, exceed this value. This requires cash flow between participants for "aggregation services". It is certainly possible that a situation will arise where this is not possible, and the microgrid will not provide a better result than participants acting alone, but on average a benefit must be apparent. This necessitates that contracts exist between microgrid participants that do not allow entry to and exit from the microgrid according to financial gain at any particular time (participants may take advantage of the microgrid when it suits them, and leave it when they are better off alone, resulting in an unfair situation for remaining microgrid participants). Presentation of detailed settlement methods is beyond the scope of this article, but an optimal microgrid operation strategy and related settlement could be drawn from game theory as mentioned above.

Aggregation services do exist in the current UK electricity trading market. Whilst offerings are few, existing services generally do not consider co-located DER or the microgrid situation. Aggregation services are generally aimed at reducing the cost participation in a deregulated market by trading through a third party, with the generator choosing the level of risk they are exposed to in terms of market price volatility and exposure to imbalance charges. Whilst these market examples are an interesting step toward generators realising the benefits of aggregation, they do not represent co-operative operation of the generators to minimise cost (and generators do not need to be physically in close proximity). The microgrid situation is rather different, as aggregation is assumed to occur on the customer (i.e. microgrid) side of the meter.

6. Conclusion

A linear programming model designed to choose the optimal system capacities and operation schedule for a microgrid has been presented. This model adds additional constraints to those currently existing in the literature in that it explicitly defines the amount of time per year that the microgrid would be expected to operate in "islanded" mode, and restricts heat flow between microgrids participants to specifically defined cases. This is a more practical representation of the microgrid than presented in the reviewed literature.

The model is applied to consider the case of a hypothetical microgrid consisting of a hospital, a hotel, and a leisure centre in the UK. Technologies available to the microgrid owner were; up to three combined heat and power units (CHP) with different electrical efficiencies, a wind farm up to 600 kWe, solar PV, electricity and thermal storage, and a boiler. The model chooses capacities of each of these technologies and their operation schedule to minimise cost of meeting demand.

It was found that the microgrid can offer a positive case for investment when compared with the situation where those demands are met via grid electricity and a boiler. The microgrid situation was necessarily more expensive than the conventional (i.e. grid connected 100% of the time) decentralised generation (DG) situation, reflecting the extra expense of installing generating capacity to meet peak load in the microgrid when operating in "islanded" mode. Whether these additional costs would be considered acceptable for the specific microgrid benefits (e.g. achievement of higher emissions savings and perhaps greater supply reliability) is a topic for further research and requiring empirical market evidence.

Finally, the differing optimal operation schedules between grid-connected and islanded systems were presented, pointing out that the islanded microgrid represents a far more constrained system and therefore exhibits a more complex cost-optimal dispatch schedule. Observation of participants' operating schedules indicates that cooperative action rather than pure self interest provides the best economic outcome for the microgrid, indicating that development of a fair settlement system between microgrid participants should be developed. Game theory provides the necessary tools to carry out such an analysis.

7. Further research

The exploratory analysis presented in this paper could be pursued in a number of ways. These relate to three primary issues;

microgrid design and the economics of reliability, drivers for the inclusion of renewable energy within microgrids, and settlement and reconciliation in microgrids.

This analysis presented has made clear that the cost of meeting peak demand with onsite generators is a primary economic consideration. In essence, this relates to the economics of reliability, with each microgrid situation required to make a judgement regarding acceptable frequency and length of outages. This consideration could be explicitly included in an optimisation framework similar to that described in this paper. Furthermore, optimal design of a microgrid (i.e. a method for choice of system capacities) could be developed, requiring minimisation of expectation of cost, not calculation of expectation of minimum cost as presented in this paper.

Drivers for inclusion of renewable generation within a microgrid could be examined more comprehensively. This article assumed no special reward for renewable generation (i.e. a free market case, without government intervention). Inclusion of existing and/or proposed support mechanisms could bear upon results significantly, providing potentially low public cost of CO_2 reduction.

Finally, as discussed above, game theory can be applied to investigate fair settlement and reconciliation for microgrid participants. Such analysis could be carried out with respect to environmental drivers and outcomes, highlighting how different participants with different motivations may interact and what economic/environmental outcomes this would produce, and what incentives may improve these outcomes.

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