Applied Energy – manuscript

Synergy of smart grids and hybrid distributed generation on the value of energy storage

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In smart grids, demand response and distributed energy systems aim to provide a higher degree of flexibility for load-shifting operations and the leverage to control intermittent wind supply. In this more dynamic energy system, deployment of energy storage at the site of consumption is envisioned to create synergies with the local distributed generation (DG) system. From a large end-user perspective, this paper contributes to the practical understanding of smart grids by modelling the impact of real-time pricing schemes (smart grids) on a hybrid DG system (mixed generation for heating and electricity loads) coupled with storage units. Specifically, we address: How does the portfolio of DG units affect the value of energy storage? and, what is the value of energy storage when assessing different designs of demand response for the end-user? To this end, we formulate a dynamic optimization model to represent a real-life urban community's energy system composed of a co-generation unit, gas boilers, electrical heaters and a wind turbine. We discuss the techno-economic benefits of complementing this end-user's energy system with storage units (thermal storage and battery devices). The paper analyses the storages policy strategies to simultaneously satisfy heat and electricity demand through the efficient use of DG units under demand response mechanisms. Results indicate that the storage units reduce energy costs by 7–10% in electricity and 3% in gas charges. In cases with a large DG capacity, the supply-demand mismatch increases, making storage more valuable.

Key words: Energy storage; smart grid; modelling; renewable; distributed generation; demand response

1. Introduction

The UK government has committed to increase the share of electricity generated from renewable energy to 20-40% by 2020-2030 (European Commission 2014). As renewable intermittency creates uncertainty in power supply, the national grid will need to raise a higher amount of balancing power (e.g. reserves) than today. For instance, a recent warning coming from UK energy regulators has noted a potential shortage of energy spare capacity for the 2015-16 winter (BBC News Business 2012, Mayor and Mokkas 2012). This warning reinforces previously raised concerns about the feasibility of ambitious EU environmental policies, which so far have predominately focused on

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increasing the share of renewable energy rather than upgrading stand-by capacity for electricity generation. As a result of these developments, the national grid is facing an unprecedented challenge of modernizing the grid infrastructure, keeping the lights on and integrating large quantities of renewables.

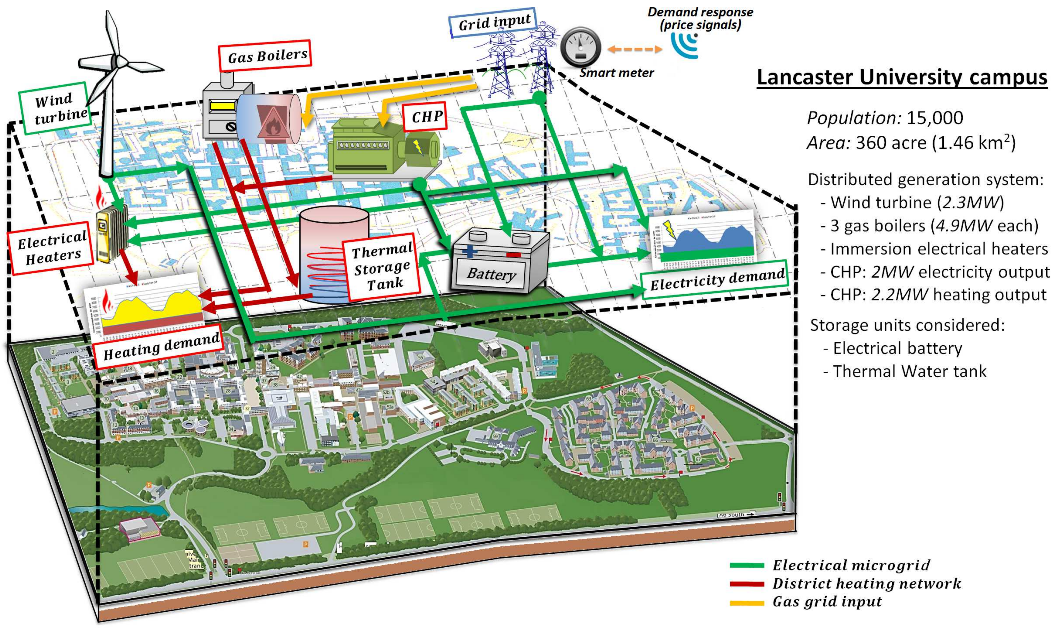

Figure 1 Schematic representation of a comunity's hybrid energy system and features of the case study.

As part of the overall strategy to address this energy system transition, the UK National Grid is currently installing smart meters nationwide (Teh et al. 2011). In smart grids, knowing and influencing consumer demand patterns, close to real-time, is setting the scene to use distributed energy systems (small/medium sized generation units) as part of the grid balancing services. Through smart demand response systems, a shortfall of electricity supply can be counter-balanced with changes in consumption patterns. Indeed, in the last years, the UK National Grid has introduced incentives for large energy users to control demand during peak hours in winter (National Grid 2014). In this context, energy storage has been promoted as the key synergy catalyst to balance the inflexibility in local supply (e.g. renewable) and to actively control demand in a smart grid (Roberts and Sandberg 2011). In the last year, for instance, Japan and Germany have launched subsidy programs to support the installation of battery systems to complement end-user distributed generation systems (Runyon 2014). Distributed energy storage increases demand elasticity, which in turn, through smart meters, enhances grid balancing services. Locally, energy storage improves energy supply strategies (energy efficiency) and hence increasing the revenue stream from distributed generation (DG). At the policy level, local energy storage provides the necessary flexibility to support further deployment of renewables via DGs systems located on site of consumption.

Despite of these synergistic potentials, in the literature, relatively limited attention has been paid to the pragmatic role of *end-user* energy storage in enhancing demand flexibility that is complimentary to grid requirements. This paper provides a bottom-up perspective – the end-user – on investigating the value of storage units have on the end-user's energy system in smart grids. Through analysing a practical example of a large end-user (community, industrial site or building complex, see Fig. 1), we discuss the conditions under which energy storage is valuable for a mix of local generation units that satisfy heating and electricity loads (hybrid energy system). To this end, the paper explicitly focuses on analysing how dynamics of local demand, energy prices and the hybrid DG profile impact the value of energy storage to answer the following research questions:

– What is the value of end-user energy storage, in the form of a battery and a thermal water tank, for heating and electricity systems?

– How does a hybrid[1] DG structure impact the value of storage units?

– As the UK National Grid is introducing demand response schemes (e.g. price signals) to enhance its electricity supply operations, we analyse: what is the value of end-user electricity storage from load-shifting operations in smart grids?

To address these questions, we study a real-life community's energy system considering energy storages for demand response and energy efficiency purposes. Lancaster University campus serves as our case study, where the hybrid DG system is composed of a wind turbine, a combined heat and power unit (CHP), gas boilers, and electrical heaters (Fig. 1). The community collects the necessary energy from the grid at prevailing prices (i.e. under a price driven demand response mechanism), but does not deliver energy to the grid. Through a dynamic optimization model we consider the inter-temporal dynamics of price, demand and renewable generation. The model's objective is to provide procurement and storage strategies that minimize the community energy costs for electricity and gas consumption over a finite planning horizon of one day. Results examines how local DG units work together to satisfy demand for comparable cases with/without storage units exposed to demand response mechanisms. We describe energy storage benefits to enhance the integration of the heating and electricity systems by focusing on:

- Synergies of the hybrid DG units portfolio and load profiles (electricity and heat) on the value of energy storage. We quantify how energy storages smooth peak demands through a more efficient utilization of the CHP and possible wind power surplus. For example, thermal storage enhances the efficient usage and operation of the boilers and the CHP.

- Energy arbitrage decisions and load-shifting operations under a demand response mechanism. Specifically, the value of electricity storage on procuring electricity at low prices and using the battery to avoid high prices.

[1] An energy system composed of more than one energy carrier is refereed as hybrid (electricity and heat mix).

In a nutshell, the paper reports on the value of end-user energy storage and its reciprocal effects on a hybrid DG system under a demand response mechanism (smart grid setting). In the next section, literature on energy storage valuation is reviewed. In Section 3, a description of demand response in relation to DG is presented. This is followed by a description of the case study and the modelling methodology (Section 4). Section 5 discusses the results from different DG case configurations. Then, conclusions and directions for future research are summarized in Section 6.

2. Related literature

Valuating energy storage has predominantly focused either on its application feature or ownership setting (see review by Zucker et al. 2013). Most studies are devoted to a supplier perspective, that is to medium or large-scale energy providers or utility at grid level. These studies predominately examine the supplier's optimal control strategies for energy storage to a mix of energy generators so as to maximize profits from its energy commitments to electricity markets (see review by Steeger et al. 2014). In contrast, this paper explores decentralized storage benefits from an end-user perspective for a micro grid that integrates renewables and district heating operations.

Recently, the assessment of end-user energy storage has gained attention due to the promising prospects of smart grids (Römer et al. 2012, Ottesen and Tomasgard 2015). Research in this area analyses the value of storage under uncertain wind supply (Crespo Del Granado et al. 2015), its contribution to micro grid operation and stability (Tan et al. 2013) and its technical benefits for power and network management (Wade et al. 2010). However, the storage literature from an end-user perspective is limited, particularly when considering integrated energy systems for electricity and heating, which – depending on the problem context – are modelled as separate structures and studied as such (see review by Mendes et al. 2011). Some literature studies, for instance, analyse thermal storage systems complemented with CHPs (Celador et al. 2011, Pagliarini and Rainieri 2010) or storages role when heating/cooling requirements are electricity driven (Arteconi et al. 2012). In Stadler et al. (2009) both thermal and electricity storage are considered with emphasis on the value of solar PV systems. This is extended in a second paper (Stadler et al. 2013) in which they examine the cost-benefits of electricity storage and the impact on CO2 emissions. Though both storage units are taken into account, the study gives little analysis on the energy unit interactions within the system. In contrast, this paper extents the analysis by including a more detailed assessment of the heating system. We highlight the heating-electricity interactions of wind power as most of the studies have only researched the effects to the electrical system or addressed engineering aspects of the technology (see Elma and Selamogullari 2012).

Additionally, this paper proposes the inclusion of demand response in the valuation of energy storage in synergy with a hybrid DG system structure. In this regard, as noted in O'Connell et al. (2014), one of the main challenges in demand response is the lack of practical experience on understanding its value and benefits in smart grids. In this literature domain, various studies have focused on behavioural aspects of the end-user (consumer reactions to prices, see Thorsnes et al. 2012). This paper, however, broadens the scope and encompasses notions of demand response to systems such as storage units, renewables, district heating and micro grids. Moreover, as the UK discusses the electrification of heating systems in the near future, a bottom-up understanding (end-user perspective) of smart grids and the role of decentralized energy storage is key to improve energy efficiency and support renewables integration (Parra et al. 2015, Crespo Del Granado et al. 2014). In summary, as existing studies have not considered the joint inclusion of wind power, heating-electricity system integration and demand response for a community based energy storage, this papers provides a detailed analysis of the synergistic effect of these factors on end-user energy storage and hence a contribution to the micro grid literature.

3. Distributed generation and demand response

Existing DG units across the UK accounts for 11% (approx.) of total supply (Carbon Connect 2012). Typically, urban communities or buildings complexes have on-site DG systems composed of a mix of solar panels, gas boilers or wind turbines who are supported by local energy distribution networks (i.e. district heating and micro grids). This local DG system satisfies heating and electricity loads along with the procurement decisions to buy electricity and gas from energy suppliers. Usually, the tariffs are agreed beforehand at a fixed retail price disregarding the time-varying marginal cost of producing electricity. In a smart grid setting, however, time-varying prices are adopted as a type of demand response to represent the grid's operational costs in real-time. Responding to economical signals creates an end-user demand profile that is more consistent with the grid's balance needs. Assuming a smart grid setting, we consider the following demand response mechanisms:

- *Balancing market prices*: The UK national grid uses a pool of bids/offers price mechanism to balance market participants in order to match discrepancies between electricity supply and demand **close** to real-time (ELEXON-Ltd 2013). This results in a time dependent electricity price that reflects the transactions of the half-hourly UK wholesale spot market. Figure 2***i*** illustrates this half-hourly time varying price in GBP/MWh.

- *Short term operating reserve (STOR)*: This tool is used by the UK National Grid to access additional power sources when critical short term events occur, for example, to manage high inaccuracies in demand forecast or unforeseen problems in generation availability. STOR is a contracted balancing service in the form of stand-by generation or demand reduction to deal with actual demand imbalances (National Grid 2014). Under a STOR arrangement, the grid instructs a service provider to make STOR capacity available, and in return pays for the energy delivered as well as a supplementary fee for 'availability offered'. Grid STOR alerts vary across the year and are related to load penalties for large end-users, known as triad warnings (Matthews and Kockar 2007).

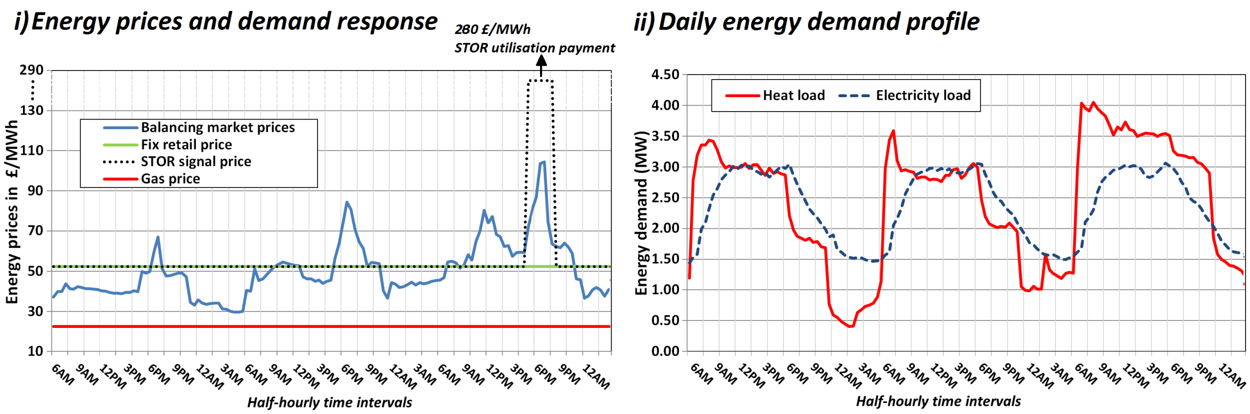

Figure 2 *(i)* Energy prices schemes considerd and *(ii)* case study demand profiles: three days in winter.

4. Modeling community energy systems

In this section we describe the modelling characterization of local DG system for a large end-user prone to adopt the demand response schemes noted. That is, we assume that the end-user is able to exploit real-time pricing information to dynamically adjust decisions to either procure, store or produce energy for a planning horizon of one day. This is divided into 48 time period intervals (half hourly based), indexed by $t = 1, 2, ..., 48$ in the model. The end-user objective is to minimize the total energy consumption cost for every single time step t under a demand response price scheme for electricity as proxy for energy cost (Fig. 2***i*** depicts the three price constellations analysed: flat or retail price, wholesale price and STOR signals). For gas prices, we use a constant price.

The following sub-sections describe the features of our case study and the DG units operational in the energy system as well as the hypothetical integration of storage units. We focus on the energy units' conversion efficiency, capacity and their role in the community's supply-demand balance.

4.1. Case study: a large end-user with DG

A typical DG infrastructure depends on the availability of local energy resources. Mainly based on the region's climate and geological conditions, these can be: wind speeds, biomass sources, small hydro reservoirs and solar irradiation levels. Usually, this local generation is supported by external energy resources in the form of natural gas supply for CHPs and thermal boilers, fuel for back up generators, and an electricity connection to the centralized national grid or local utility. This makes Lancaster University campus an ideal profile of a small community dependent on its own hybrid DG sources and grid supply to satisfy heating and electricity loads (Fig. 1).

The university's campus energy system is designed around a "central service spine" that contains all major mechanical and electrical services needed to connect buildings throughout campus. This central service contains a district heating network and an electrical micro grid. These are operated from a central facility containing the gas thermal boilers and the CHP. The campus has a daily average heating demand of 105MWh and 95MWh for daily electricity consumption. Maximal peak loads (in one hour) for heat and electricity are about 10MWh and 6.2MWh, respectively. The illustrations in Figure 2***ii*** show a typical daily bell-shaped electricity demand profile (dash line) stemming from the combination of load patterns from office buildings and housing residences. The heating demand profile (solid line) is a function of the temperature requirements for space heating and hot water. For instance, the 6–8 a.m. morning peak comes from heating up student residences, lecture theatres and offices across campus. As the day progresses, at midday, the heating demand decreases due to the raising ambient temperature.

4.2. Electricity system and DG units

A community with DG has a confined electrical distribution network commonly refereed as "micro grid" which is connected to the national grid. The aim of a micro grid (or local network) is to combine all the producing energy sources in one domain to meet an aggregated demand coming from various buildings or end-users. Usually, generation and demand in a micro grid are interconnected at low voltage based on a defined electrical grid architecture. This means that a coupling transformer is used to interface the micro grid with the grid operator in order to synchronize, via a switchgear, the distribution voltage level and frequency. For instance, the university campus presently owns, operates and maintains its own high voltage ring circuit consisting of various substations transformers. The local company supplier (North West Electricity Ltd.) supplies a total capacity of 10.5 MWh as grid connection.

By modelling the DG electrical units shown in Figure 1, on the supply side we have: wind generation input $w^{(t)}$, grid input connection $E_{grid}^{(t)}$, battery discharge $B_d^{(t)}$ and the CHP input $G_{chp}^{(t)}$. These inputs satisfy the electricity demand $d_e^{(t)}$, electrical heaters $A_{el}^{(t)}$, and the possible battery charging intake $B_c^{(t)}$. This electricity supply-demand interplay inequality is represented as follows:

$$\overbrace{w^{(t)} + E_{grid}^{(t)} + B_d^{(t)} + \eta_{chp\to el} \cdot G_{chp}^{(t)}}^{\text{Wind+Grid+Battery}\Downarrow\text{+CHP}} \geq \overbrace{d_e^{(t)} + A_{el}^{(t)} + B_c^{(t)}}^{\text{Demand+Electric heaters+Battery}\Uparrow} \quad ,\forall t \tag{1}$$

Any supply surplus on eq. (1) left-hand side is assumed to be wasted as we consider a confined non-delivery end-user. Here, the main **electrical** DG unit is the wind turbine which has the following technical description and characteristics:

Wind turbine, Wind turbines' energy output depend mainly on wind speeds, height of the installation and in lesser extent to the ambient pressure and temperature. Usually, this energy generation output is explained by the so-called *power curve* that represents an empirical relationship between wind speeds and output power. Currently, the campus operates a wind turbine[2] with the

[2] Lancaster University, wind turbine details: `http://www.lancs.ac.uk/sustainability/`

technical characteristics of the Model E70 manufactured by ENERCON GmbH (2010). The wind turbine has a maximum power output of 2.3 MW. In the optimization model, for every period t, we gathered the corresponding time series for wind generation and treat them as a parameter $w^{(t)}$.

4.3. Hybrid energy units

As a hybrid energy system, the end-user energy system has specific DG units that connect the electric sub-system with the heating sub-system. In our case, the two systems interact (see Fig. 1 & 3) through the CHP by-product energy output and the electrical heaters.

Electrical heaters In district heating, some users (buildings) sometimes have extra heating sources due to: distance from the main central station (district heating loses), connection disruption, seasonality requirements, or custom heat requirements (e.g. in our case study: research labs or a swimming pool). The campus operates "satellite-rooms" or heat stations, for some buildings, in which there are electric immersion heaters that complement heat load requirements. For our model, we aggregate the energy output of these electric heaters (A_{el} notation in eq. 1) and use a typical electricity to heat conversion efficiency of $\eta_{el\rightarrow he} = 0.9$. Hence, in the model, electrical heaters are central to link the electricity system with the heating system. Especially when there is leftover wind electricity. As a result, in this paper, a setting is defined or refereed as **hybrid** when electrical heaters are part of the system (non-hybrid otherwise, $A_{el} = 0$).

Combined heat and power (CHP) We model the CHP as a "co-generation" unit that recovers exhaust heat produced from a thermal turbine's electricity generation. This is a single process that uses gas or fuel to simultaneously generate heat and power. In district heating, CHPs are mainly used to generate heat for space heating or/and hot water from the electricity generation by-product. For example, a CHP could produce 36 kWh of electricity and 50 kWh of heat from 100 kWh of gas. These two outputs could also be generated separately by a gas boiler and a gas thermal power. But, since their individual efficiencies are around 90% and 55% respectively, the total gas required to produce each individual demand would be 120 kWh. Consequently, producing heat and electricity simultaneously reduces the marginal source (gas) as well as carbon emissions.

For our model we use $G^{(t)}_{chp}$ as the notation for the CHP's gas input. To represent the CHP's energy output efficiencies/conversion rates for heating and electricity generation, we use $\eta_{chp\rightarrow he}$ and $\eta_{chp\rightarrow el}$ respectively. Lastly, the CHP's maximum gas capacity intake (γ_{chp}) defines the bound:

$$G^{(t)}_{chp} \leq \gamma_{chp}, \forall t \tag{2}$$

The CHP unit used in our case study[3] has a gas conversion efficiency $\eta_{chp\rightarrow el} = 0.4$ for electricity generation and $\eta_{chp\rightarrow he} = 0.45$ for heating. The CHP maximum gas intake is $\gamma_{chp} = 4.9$MWh so,

[3] Lancaster University, CHP details: http://www.lancs.ac.uk/sustainability

for example the maximum electricity generated after loss is $G_{chp} \cdot \eta_{chp \to el} \approx 1.96$MWh (Lancaster University 2011, Danish Energy Agency and Energinet.dk 2012). To maintain a high efficiency in these conversions rates, the CHP is typically used as base load and it is run at maximal capacity all the time. Consequently it is treated as a parameter on the model formulation.

4.4. Heating system and DG units

In our case study, the district heating infrastructure is supported by two gas boilers, and a CHP provides the primary base load heat (Lancaster University 2011). In a nutshell, the heat is generated from a central building and distributed through pipes (network of insulated pipes consisting of feed and return lines) to heating stations located within individual buildings. Then, the heat is transferred via non storage heat exchangers for space heating systems and via storage calorifiers for hot water usage (see Watkins 2011 for details on district heating). Thus, by modelling the heating demand side equation: we have the community demand for hot water & space heating noted by $d_h^{(t)}$ and the charging of the thermal storage $H_c^{(t)}$. This heating demand is met by the heat supply sum coming from electrical heaters $A_{el}^{(t)}$, thermal gas boilers $G_{boiler}^{(t)}$, and CHP heating generation $G_{chp}^{(t)}$. This defines the heat supply-demand inequality:

$$\overbrace{\eta_{el\to he} \cdot A_{el}^{(t)} + \eta_{boiler} \cdot G_{boiler}^{(t)} + \eta_{chp\to he} \cdot G_{chp}^{(t)} + H_d^{(t)}}^{\text{Electric heaters+Gas boilers+CHP+thermal storage}\Downarrow} \geq \overbrace{d_h^{(t)} + H_c^{(t)}}^{\text{heating demand + thermal storage}\Uparrow}, \forall t \quad (3)$$

As it is common to have district heating network losses, a 10% loss factor is considered to the supply side in Eq. (3) . Basically, district heating generation units are multiplied by 0.9.

Gas thermal boilers Gas thermal boilers are the conventional method to satisfy local space heating and domestic hot water requirements. In DG, gas boilers are adopted for district heating in order to provide supplementary provision to the CHP and other heating technologies. For example, the gas fired boilers will operate once demand exceeds the combined capacity of the CHP unit and thermal storage. To support the supply-demand balance equation (3), the boiler converts gas ($G_{boiler}^{(t)}$) to heat subjected to an energy conversion efficiency rate (η_{boiler}). The boiler has a maximum gas capacity intake γ_{boiler} which defines the following bound:

$$G_{boiler}^{(t)} \leq \gamma_{boiler}, \forall t \quad (4)$$

Our case study currently operates two gas thermal units with an individual heat output of 4.8 MWh under an efficiency rate of $\eta_{boiler} = 0.9\%$ (Lancaster University 2011, Danish Energy Agency and Energinet.dk 2012).

4.5. Energy storage technologies

An electrical battery and a thermal water tank are taken into consideration as the appropriate storage devices to complement the case study's hybrid DG system.

Electricity storage The main benefit of electricity storage is its contribution to energy ramping and frequency control, as well as its ability to shift bulk energy over periods of several hours to smooth renewable output and correlate it with demand. In our case study, a battery would store electricity from the wind turbine and the CHP when their generation is not fully consumed and it is a mechanism to perform energy arbitrage decisions (avoid high energy prices).

Today's electricity storage technologies are mainly based on chemical reactions (most batteries) and mechanical (compressed air or pumped storage); for a review see Luo et al. (2015). In general, the main performance indicators for storage technologies, are the storage capacity ($S_b^{(t)}$), the maximum rates for charging (α_b) and discharging (β_b), and the round-trip efficiency for charging/discharging power ($\eta_{eff} \in [0,1]$, i.e., $1-\eta_{eff}$ is the percentage loss). Depending upon the battery technology of choice, a minimum depletion threshold is recommended for the storage level ($S_b^{(t)}$). This is due to the battery charging/discharging rates are sensible to the storage level inside the battery which might affect its performance. Typically to optimize the charging/discharging rates and to prolong the battery lifetime, a 30 to 40% of the battery capacity is recommended as the minimum discharge level (Leadbetter and Swan 2012). Hence, for our model we define a lower bound S_b^{min} and upper bound capacity S_b^{max} for the stored energy level $S_b^{(t)}$.

$$S_b^{min} \leq S_b^{(t)} \leq S_b^{max} \tag{5}$$

Likewise, charging the battery $B_c^{(t)}$ in each period t, (comes from the grid, CHP or wind turbine in equation 1) is bounded by a maximum charge rate α_b:

$$0 \leq B_c^{(t)} \leq \alpha_b \tag{6}$$

Similar rate, noted as β_b, bounds the maximum battery discharge $B_d^{(t)}$ in each period t :

$$0 \leq B_d^{(t)} \leq \beta_b \tag{7}$$

Lastly, the inter-temporal dynamics of the amount of electricity stored ($S_b^{(t)}$) in the battery at each time t must satisfy the balance:

$$S_b^{(t-1)} + \eta_{eff} \cdot B_c^{(t)} - B_d^{(t)} = S_b^{(t)} \tag{8}$$

This constraint illustrates that the electricity stored in the battery at the end of time period t ($S_b^{(t)}$) is decided by the previous time period inventory level ($S_b^{(t-1)}$) and the battery operations in

t (charge or discharge, i.e., $B_c^{(t)}$ or $B_d^{(t)}$). Note that we do not take into account custom aspects on the internal impedance of the battery from the state of charge or other engineering operational details. In (8) we assume that there is an approximate linear relationship between energy capacity (S_b^{min}, S_b^{max}) and power capacity (α_b, β_b) as well as their effect to efficiency (η_{eff}).

To select the appropriate battery parameters for our community-based energy system, we reviewed demonstration projects that considered mega-watt class battery (see the United States Department of Energy database for examples). Among these cases, the vanadium redox flow battery (VRFB) has shown strong prospects to become a mature technology for long duration services applicable to micro grids. This battery has a variety of applications in power quality control, stabilization of renewable energy, and emergency power among others (Kear et al. 2012). Although other battery types, lithium-ion for example (Parra et al. 2015), are also suitable for our setting, we use the VRFB more as a generic example of electricity storage rather than focusing on technological aspects of storage devices (see Tapbury Management Ltd for a similar example).

In this regard, we gather the basic battery parameters based on a standard battery module[4] detailed in the Prudent Energy Corporation catalogue. For our half hourly intervals, the maximum capacity per module is $S_b^{max} = 250$kW. To achieve a round-trip efficiency of $\eta_{eff} \approx 80\%$, the recommendable minimum threshold is set to $S_b^{min} = 50$kWh (Divya and stergaard 2009). Lastly, the discharge rate is $\alpha_b = 100$kWh and the charge rate is $\beta_b = 65$kWh. This battery module size is scaled up to match the case study, namely a 4MWh and 8MWh (S_b^{max}). Besides, we adopt these sizes so it is in line with STOR availability capacity requirements (Matthews and Kockar 2007).

Thermal storage Thermal storage has been broadly used in DG to increase the performance of heating systems when there is a mismatch between production and demand. For example, in the presence of a CHP, thermal storage creates the flexibility to decouple the heat production from the electricity production (Streckien et al. 2009).

The basic principle behind thermal storage is to release (or absorb) energy by reducing or increasing the temperature of a material. A popular and widely used form of thermal storage for DG are hot water tanks. Thermal energy in a water tank is created due to buoyancy forces, which ensure the highest temperature at the top and the lowest temperature at the bottom of the tank. During the charging process, hot water is supplied to the top of the tank, and the same amount of cold water is taken out from the bottom of the tank. During the discharge of thermal store, an opposite process takes place. In this regard, the capacity of the heat storage facility is characterized by its volume and the amount of thermal heat stored (water temperature). The standard means of measuring thermal heat in Wh is by calculating the temperature difference (known as ΔT) of

[4] Based on performance characteristics of Prudent Energy's standard VRB-ESS MW-Class module, 250KW battery

the water's temperature (T_{tank}) minus the ambient temperature (T_a). This difference is multiplied by the water mass m and the water heat capacity coefficient, c_{wh}= 1.16Wh/^{o}Ckg. For instance, the power content of a thermal water tank (noted by S_h) of m =300,000 litres with an average temperature of T_{tank} =80°C, and an ambient temperature of T_a =15°C will be: $S_h = m \cdot c_{wh} \cdot (T_{tank} - T_a) \approx$22.6 MWh. Now since the water's temperature boiling point is 100°C and that temperatures below 40°C can cause legionella outbreaks, the water tank's temperature is typically operated by a maximum T_h^{max} temperature of 90°C and a minimum T_h^{min} temperature of 50°C (Pagliarini and Rainieri 2010).

$$T_h^{min} \leq T_{tank}^{(t)} \leq T_h^{max} \tag{9}$$

Thus, based on (9) temperature interval, the thermal storage capacity S_h is restricted to $S_h^{min} \approx$ 12.2MWh and $S_h^{max} \approx$ 26.1MWh (see Table 1). Similar to the battery device, the thermal storage role on the heat energy supply-demand interactions on equation (3) is defined by the heat storage charge ($H_c^{(t)}$ on the supply side) and heat storage discharge ($H_d^{(t)}$ on the demand side). Then, we have the following inter-temporal equilibrium for each time interval t:

$$\overbrace{(1-\tau)S_h^{(t-1)}}^{\text{Stored at t-1}} + \overbrace{H_c^{(t)}}^{\text{charge heat input}} - \overbrace{H_d^{(t)}}^{\text{discharge to demand}} = \overbrace{S_h^{(t)}}^{\text{Stored at the end of t}} \tag{10}$$

In this equality constraint, τ represents the storage insulation heat loss factor or self-discharge (within time intervals) which is typically 1-5% per day (Dinçer and Rosen 2010).

The water tank used for the case study is comparable to the manufacturing specifications of Ratiotherm-UK Ltd (2014) water tanks. We consider a $m = 300,000l$ (or $300m^3$) and a loss or self discharge $\tau = 0.001$ per time step (Danish Energy Agency and Energinet.dk 2012). These choice of parameters are also analogous to a case analysed in Streckien et al. (2009). Note that equality (10) assumes that the thermal storage works as a "heat accumulator". This represents the limiting case where we considered the water to be at an uniform or average temperature. A similar approach and assumptions are considered in Celador et al. (2011).

Table 1 Energy units data specifications of parameters (half hour based)

		Battery storage sizes	
Water tank storage	Heating units*	4MW Battery	8MW Battery
$S_h^{max} \approx$26.1MW($T_h^{max} = 90C^o$)	$\gamma_{boiler} = 2.65$MW	S_b^{max}=4MW	S_b^{max}=8MW
$S_h^{min} \approx$12.2MW($T_h^{min} = 50C^o$)	η_{boiler}=0.9	S_b^{min}=0.8MW	S_b^{min}=1.6MW
$m = 300,000l$	$\eta_{el \to he}$=0.9	α_b=1.04MW	α_b=2.08MW
$\tau = 0.001$	$\eta_{chp \to he}$=0.45	β_b=1.6MW	β_b=3.2MW
$T_a = 15C^o$	$\eta_{chp \to el}$=0.4	η_{eff}=80%	η_{eff}=80%
	γ_{chp}= 2.45MW		

* 10% energy losses is applied to each unit efficiency ($\eta \cdot 0.9$) due to district heating distribution.

4.6. Model formulation

The objective function minimizes the energy cost of the 48 half-hourly time intervals (t) for a finite time horizon of one day. To calculate energy costs, the model uses a type of demand response price scheme for electricity ($p_{el}^{(t)}$) and a fix gas price ($p_{gas}^{(t)}$). This splits the objective function (11) in two parts: cost of the gas consumption incurred by the gas boiler and the CHP, and the cost of electricity consumption from the grid. The model formulation is as follows:

$$\underset{t=1,t=2,...,t=48}{\textbf{Minimize}}(\text{Energy cost}) = \left\{ \overbrace{\sum_{t=1}^{48}[p_{el}^{(t)} \cdot E_{grid}^{(t)}]}^{\text{Electricity grid}} + \overbrace{\sum_{t=1}^{48} p_{gas}^{(t)} \cdot [G_{chp}^{(t)} + G_{boiler}^{(t)}]}^{\text{Gas consumption}} \right\} \tag{11}$$

Subject to ($t = 1, ..., t = 48$):

$$\textit{Supply} \geq \textit{demand} \begin{cases} \eta_{el\to he} A_{el}^{(t)} + \eta_{boiler} G_{boiler}^{(t)} + \eta_{chp\to he} G_{chp}^{(t)} + H_d^{(t)} \geq d_h^{(t)} + H_c^{(t)} & \text{heating} \\ w^{(t)} + E_{grid}^{(t)} + B_d^{(t)} + \eta_{chp\to el} G_{chp}^{(t)} \geq d_e^{(t)} + A_{el}^{(t)} + B_c^{(t)} & \text{electricity} \end{cases}$$

$$\textit{Storage inter-temporal balance} \begin{cases} S_b^{(t-1)} + \eta_{eff} B_c^{(t)} - (B_d^{(t)}) = S_b^{(t)} & \text{for electricity storage} \\ (1-\tau) S_h^{(t-1)} + H_c^{(t)} - H_d^{(t)} = S_h^{(t)} & \text{for thermal storage} \end{cases}$$

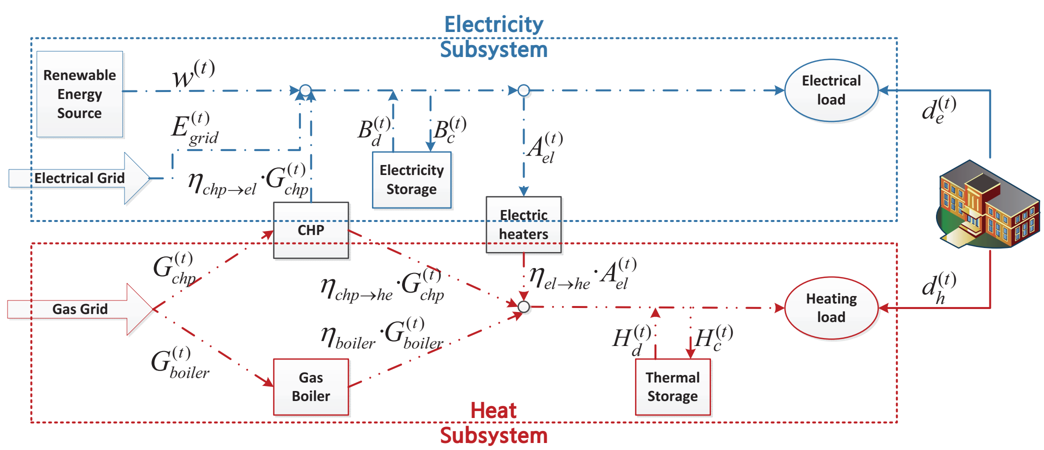

Figure 3 Schematic of the energy system with variables and parameters notation (Table 4).

Above formulation also considers non-negativity of the decision variables as well as the capacity bounds described for gas boilers in (4), the CHP in (2), battery in (5) -(7) and thermal storage in (9). All parameters are assumed to be deterministic. Figure 3 illustrates a schematic of the model along with the parameters and decision variables used (notations summary in Table 4, appendix).

5. Numerical study

5.1. Implementation setting

In addition to gathering the data-sets for demand and wind energy from Lancaster University campus, we use the half-hour UK reference price index settled for each day to reflect the electricity price in the balancing market for 2012–2013 (ELEXON-Ltd 2013, APX Group UK 2014). The model is applied to the period when the district heating is operational, in our case from September 20^{th} to May 31^{sth} in 2012–2013. Table 1 parameters are implemented in the model which is programmed and solved in Matlab®. Other remarks regarding model implementation are as follows:

- *Start-end storage level*: An important modelling feature is to define the initial amount of energy available in the storage devices. Since we calculate the dynamics of supply-demand balance for each day separately, we set the **starting** storage capacity ($S^{t=1}$) to begin with a fully charged storage ($S^{t=1} = S^{max}$). Likewise, the **end** storage level is set to $S^{t=48} = S^{max}$. This way all end-of-horizon effects are resolved avoiding a total or sudden discharge at the end of the day. As the main storage discharge operations occurs during the morning peak, the model is set to start at 6 a.m. ($t = 1$) and to end at 5:30 a.m. ($t = 48$) for each optimization instance (see a similar procedure in Crespo Del Granado et al. 2015).

- *Electricity and gas prices*: Typical grid energy prices are composed of distribution and transmission charges, supply costs, and wholesale market prices. To implement either a time-varying or a fixed retail electricity price that is comparatively consistent for the valuation of energy storage, we use wholesale electricity prices as proxies for energy costs (not what the end-user actually pays). With these proxies, we calculate the average cost per MWh to serve as fixed retail contractual price for our baseline case, i.e. 55 GBP/MWh, while for gas prices we use the case study's contractual gas price agreement of 22 GBP/MWh (fix $\forall t$, refer to Fig. 2i).

5.2. Results and insights: a base-case

The purpose of the *base-case* is to show the reciprocal influences between the hybrid DG system and the storage units **without** the influence of demand response – a setting with fixed electricity price for every time step t ($p_{el}^{(t)} = 55$ GBP/MWh). Therefore, the model optimizes the usage of wind and CHP **surpluses**. Table 2 summarizes the annual results of this base case while Figure 4 provides an illustrative two day example of the supply-demand dynamics. We highlight the following:

Electricity sub-system: Figure 4***i*** shows the electricity supply-demand balance under a constant price, in which battery charging operations occur when supply (wind + CHP) surpasses demand. In day-1 for instance, the battery is gradually discharged throughout the day in expectations of wind surplus which recharges the battery in full at night. In day-2, however, no supply surplus is foreseen which leads to no battery operations. Table 2 annual results indicate that the CHP satisfied 49.6%

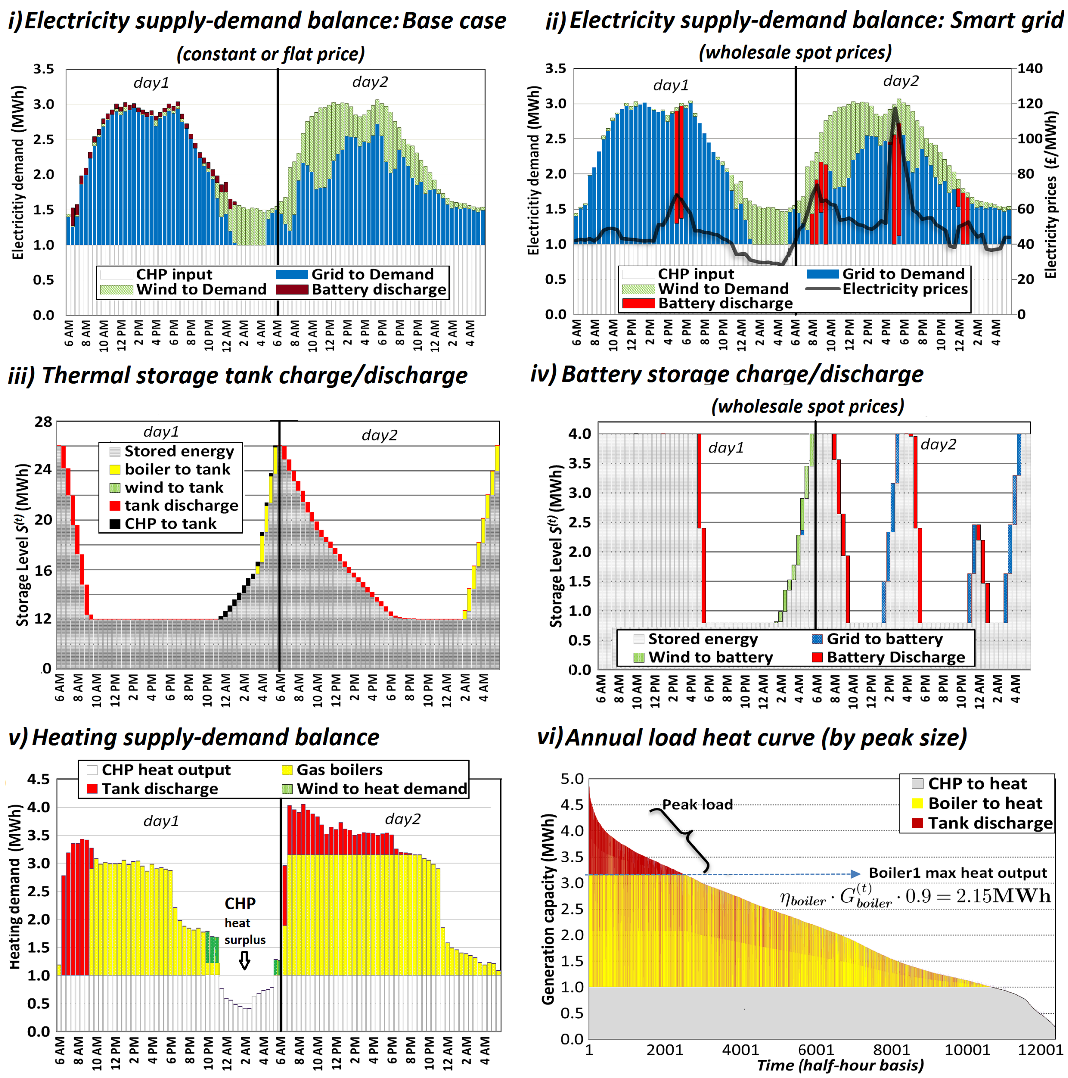

Figure 4 Illustrative results on the energy supply-demand dynamics (discretized in 30 min intervals.)

of the electricity demand, the grid covered 37.5% of the load and 12.1% came directly from the wind turbine. The remaining 0.8% came from storing wind surplus through battery operations.

In short, under a fixed price regime, the optimal decision is firstly to take up any wind available for electricity demand consumption (85% of wind output). Then, the model diverts any wind leftover to the battery (6.6%) and later to the heat load (5.2%) and to thermal tank (2.5%). Hence, the combination of operating a hybrid structure with battery presence is that only 0.7% of the wind is wasted while in the reference case annual wind losses are up to 15% (see Table 2).

Heating sub-system: Energy heating dynamics in Figure 4***v*** show the role of the CHP as base load while the rest of the heat demand is met by the boilers and thermal storage discharge. In both days, thermal storage covers peak time, especially on day-1 where the storage is discharged rapidly to cover the morning peak so as to minimize self-discharge losses τ (storing the heat for a longer time increases losses). Overall, annual heat results show that the CHP meets 44.2% of the heat demand while gas boilers and thermal storage provides 42% and 13.2% respectively. Wind energy, through electrical heaters, contributes the remaining 0.6%.

Basically, to exploit valuable conditions from thermal storage and the hybrid structure, the optimal operating policy is to dispatch wind (leftover from electricity usage) first to heating demand and then to the thermal storage. Also, if the CHP overproduces heat, the thermal tank saves it while in the reference case (no storage) 4% of the CHP heat output is lost (day-1 night, Fig. 4***v***).

Since the thermal storage takes over peak heat demands, we observe two important insights valuable to the heating system: First, the thermal storage allows a more efficient operation of the gas boilers by running the boilers at maximal capacity. On day-2 for example (Fig. 4***v***), the gradual thermal storage discharge avoids turning on a second boiler[5]. If a boiler operates at low capacity, it decreases its conversion efficiency (η_{boiler}) performance which increases gas expenses. Second, the annual load duration diagram in Figure 4***vi*** demonstrates the storage role as a peak shaving mechanism associated with the usage of boiler capacity. That is, we could either invest in a larger boiler that covers the heat demand single-handedly or use a second boiler to cope with peak demands. Hence, note that having a thermal storage avoids the need to invest in a large boiler or operate multiple ones – an additional storage value that should be studied further in more detailed cost-benefit assessment of the energy system.

The value of storage units and the hybrid system: The economic performance of storage units is assessed through a ceteris paribus analysis detailed in Table 2. Cost savings of three different system configurations are compared to a reference case (non-hybrid system without storage units). For example, under a hybrid system but without storage units, *excess* wind is only used for heating purposes which yields gas cost savings of 1.5%. Adding thermal storage to the hybrid setting generates 4.24% in gas cost savings for the heating system. However, if a battery is added to this system, gas savings drop to 3% as the battery generates 2% savings in electricity costs. These relationships are explained by the following conditions:

- Interactions between the two energy systems are valuable for the heating system and indifferent for the electricity system. Since electricity prices are higher than gas prices (Fig. 2***ii***), the model prioritizes savings on the electricity side. The battery maximizes wind savings to serve electricity demand. In fact, the direct interplay and contribution between the two storage units is not always favourable for the thermal tank. For example, wind contributes 6% of its output to thermal storage when no battery is in place while battery presence results in a drop to 2.5%. Likewise, wind surplus satisfies 0.9% of heat demand in the absence of a battery, but drops to 0.6% when a battery is part of the system configuration.

[5] The model formulation has one variable per boiler (G_{boiler}). But the model prioritizes the usage of the first boiler at its fullest (we added a negligible increase on the gas price paid by the second boiler).

Table 2 ***Base-case*** results analysis. Annual demand of electricity: 24.4GWh and heating: 26.3GWh. Wind generation output: 3.49GWh. CHP heat and electricity output: 12.2 GWh and 12.1 GWh.

	Reference case	**Energy system configuration**		
Base case: Constant price (fix)	*Battery* ✗ *Thermal-tank* ✗ *Hybrid system* ✗	Battery ✗ Thermal-tank ✗ Hybrid system ✓	Battery ✗ Thermal-tank ✓ Hybrid system ✓	Battery ✓ Thermal-tank ✓ Hybrid system ✓
Total annual electricity cost	**£507,222**	£507,222	£507,222	£497,197
Total annual heating (gas) cost	**£398,905**	£392,589	£382,007	£386,968
% of *electricity demand* met by battery	-	-	-	0.8%
% of *electricity demand* met by wind	12.1%	12.1%	12.1%	12.1%
% of *electricity demand* met by CHP	49.6%	49.6%	49.6%	49.6%
% of *electricity demand* met by the Grid	38.3%	38.3%	38.3%	37.5%
% of *heat demand* met by wind	-	0.9%	0.9%	0.6%
% of *heat demand* met by thermal tank	-	-	13.2%	13.2%
% of *heat demand* met by CHP	44.3%	44.3%	44.2%	44.2%
% of *heat demand* met by Boiler	55.7%	54.8%	41.6%	42.0%
% of boiler input to *thermal storage*	-	-	83.3%	86.2%
% of CHP input to *thermal storage*	-	-	12.2%	11.9%
% of wind input to *thermal storage*	-	-	4.5%	1.9%
% of *wind generation* to battery	-	-	-	6.6%
% of *wind generation* to thermal tank	-	-	6%	2.5%
% of *wind generation* to heat demand	-	8.3%	8.2%	5.2%
% of *wind generation* to electricty demand	85%	85%	85%	85%
% of *wind generation* wasted	15%	6.7%	0.8%	0.7%
% of *CHP heat generation* wasted	4.1%	4.1%	0.6%	0.6%
% Electricity cost savings	-	0%	0%	2% *(£10,025)*
% Heating (gas) cost savings	-	1.5% *(£6,034)*	4.24% *(£16,898)*	3% *(£11,937)*

- The synergy of the storage units and the hybrid DG system results into a better utilization and operation of the CHP. Consider the CHP without thermal storage: 96% of its heat output is utilized for heat demand. Remember that we have a constant gas input to the CHP which provides a continuous production of electricity and heat. However, a lack of thermal storage presence would make the CHP idle at times of low heat demand, as there are more efficient ways to acquire/produce electricity if the heat is discarded. Since the CHP is heat-driven, the thermal storage decouples the heat production from the heat load. Thus, providing flexibility to continue producing electricity even though heat demand is low (any surplus is saved by the thermal storage or an analogous situation on the electricity side with the battery). This is an important value from thermal storage since the benefits are for both systems as a hybrid structure. Hence, a larger CHP capacity, would make the hybrid system even more valuable as long there are storages for support.

5.3. The value of electricity storage under demand response

In a non time-variant price environment, the battery value and its operational strategies are uniquely conditioned to store supply surplus. Now, if the community participates in one of aforementioned demand response schemes (Section 3), the battery additionally captures the value of energy arbitrage decisions. For instance, supply-demand energy dynamics reshape the battery charge/discharge conditions if compared to a flat price (Fig. 4***i*** vs. ***ii***). Table 3 shows the annual electricity costs depending on the demand response case for two battery sizes.

Wholesale (Balancing market prices): Figures 4***ii*** and 2***ii*** show typical patterns of wholesale electricity prices with two important peaks: morning (7 to 10 a.m.) and evening (4 to 7 p.m.). Here, the storage strategy is to procure energy (battery charging) when the consumption price is low and then use the stored energy (battery discharging) to satisfy demand during peak pricing periods. Observe chart ***ii***, day-2: low prices in the middle of the day created the opportunity to recharge the battery in preparation for the evening peak price.

Results indicate that the saving potentials of electricity storage (4MW battery) in combination with demand response is higher than constant prices (base-case), namely up to 7.1% instead of up to 2%. That is, dynamic pricing increases battery usage through the synergy effect of coupling DG (renewable) and load-shifting conditions with the battery. As such, the battery satisfies 4% of the electricity load compared to 0.8% in the *base-case*. Here, the electricity storage policy is to firstly exploit the available renewable electricity (wind surplus) and then avoid to procure grid electricity at high peak prices (load-shifting). Since demand response does not influence wind-battery charging decisions, wind surplus to heat loads remains unchanged. However, under a larger battery (8MW) the heating system loses some electricity-to-heat due to a greater capacity to capture wind. This in turn increases electricity cost savings to 11.4%.

Short term operating reserve (STOR) price signals: STOR signals are issued to reduce demand consumption at particular periods in exchange for availability payments (around 280£/MW, see Fig. 2***ii*** STOR signal). According to Flexitricity Ltd (2013) and National Grid (2014), there are around 40 to 60 signals per year. Typically, these price signals last for a couple of periods (1 or 2 hours). Thus, storage arbitrage strategies are similar to the wholesale case but occur for a short period and on specific days.

In 2012-2013, three out of these STOR signals were classified as triad warnings (Flexitricity Ltd 2013). During these triad periods large end-users or industrial sites in the UK are frequently called upon to forcefully reduce demand consumption or pay a hefty price for electricity consumption. In our case study, triad charges cost Lancaster University around £50,000 in previous years (Lancaster University 2014). In our model, under a STOR scheme, we assume that the large end-user is exposed to these signals as well as to triad periods. Hence, the STOR reference case (Table 3) faces penalties from triad charges as no demand elasticity (storage) exists. However, with battery presence, the cost savings come from avoiding the triad periods and by taking advantage of the STOR payment periods. Here the value of the battery is around 5.6% in cost savings.

Table 3 Value of energy storage in demand response cases and other energy mix profiles.

Case profiles		*Reference case** NO storages	With battery & thermal storage 4MW battery	8MW battery
Wholesale spot price	Total annual electricity cost	**£510,559**	£474,274 *(-7.1%)*	£452,288 *(-11.4%)*
	% of *electricity demand* met by battery	-	4.0%	7.3%
	% of *electricity demand* met by CHP + wind	61.7%	61.7%	61.7%
	% of *electricity demand* met by the Grid	38.3%	34.3%	31.0%
	Cost savings and % electricity savings	-	7.1%(£36,285)	11.4%(£58,271)
STOR price signals	Total annual electricity cost	**£521,027**	£491,702	£486,747
	% of *electricity demand* met by battery	-	2.1%	2.6%
	% of *electricity demand* met by CHP + wind	61.7%	61.7%	61.7%
	% of *electricity demand* met by the Grid	38.3%	36.2%	35.7%
	Cost savings and % electricity savings	-	5.6%(£29,325)	6.6%(£34,281)
Additional wind turbine with wholesale prices	Total annual electricity cost	**£426,259**	£387,823 *(-9%)*	£366,142 *(14.1%)*
	Total annual heating (gas) cost	**£366,874**	£352,623 *(-3.9%)*	£355,336 *(-3.1%)*
	% of *electricity demand* met by battery	-	3.9%	7.0%
	% of *electricity demand* met by CHP + wind	68.0%	68.0%	67.9%
	% of *electricity demand* met by the Grid	32.0%	28.1%	25.1%
	% of *wind generation* to battery	-	5.5%	8.0%
	% of *wind generation* to heat demand	20.9%	19.0%	18.3%
	% of *wind generation* to thermal storage	-	7.3%	6.2%
	% of *wind generation* to electricty demand	64.3%	64.2%	64.0%
	% of *wind generation* wasted	14.8%	4.0%	3.5%
50% Larger CHP with wholesale prices	Total annual electricity cost	**£260,621**	£219,930 *(-15.6%)*	£201,327 *(-22.8%)*
	Total annual heating (gas) cost	**£260,158**	£219,346 *(-15.7%)*	£222,122 *(-14.6%)*
	% of *electricity demand* met by battery	-	3.4%	6.1%
	% of *electricity demand* met by CHP + wind	81.4%	81.4%	81.4%
	% of *electricity demand* met by the Grid	18.6%	15.2%	12.5%
	% of *heat demand* met by wind	1.8%	1.7%	1.6%
	% of *heat demand* met by thermal tank	-	12.3%	12.3%
	% of *heat demand* met by CHP	61.8%	61.8%	61.8%
	% of *heat demand* met by Boilers	36.4%	24.2%	24.3%
	% of *thermal storage* charged from boilers	-	49.1%	51.7%
	% of *thermal storage* charged from CHP	-	42.4%	42.4%
	% of *thermal storage* charged from wind	-	8.5%	5.9%
	% of *wind electricity supply* wasted	34.2%	10.8%	9.4%
	% of *CHP heating supply* wasted	10.8%	2.8%	2.8%

**Reference case is without storage units but with hybrid interactions.*

5.4. The impact of DG capacity size on the value of storage units

Since energy arbitrage and DG supply surplus are the main drivers behind storage procurement strategies, we analyse the impact of an additional wind turbine or a larger CHP device compared to the base-case. We assume that the second wind turbine experiences the same wind speeds, so it generates an identical energy output as the current wind turbine. As for the CHP, its energy output is increased[6] by 50% for heating and electricity ($\gamma_{chp} = 7.4$MWh). Results of these DG capacities in Table 3 show a significant reduction in costs since less energy is procured from the grid. Also, note that since the mismatch between DG output and heat/electricity loads are more significant than in the *base-case*, the value to the storage units and the hybrid interactions increases as follows:

[6] For instance, Streckien et al. (2009) with a similar CHP/thermal-storage configuration argues that thermal storage is almost unnecessary with a 1MWh output as is used as a simply base load.

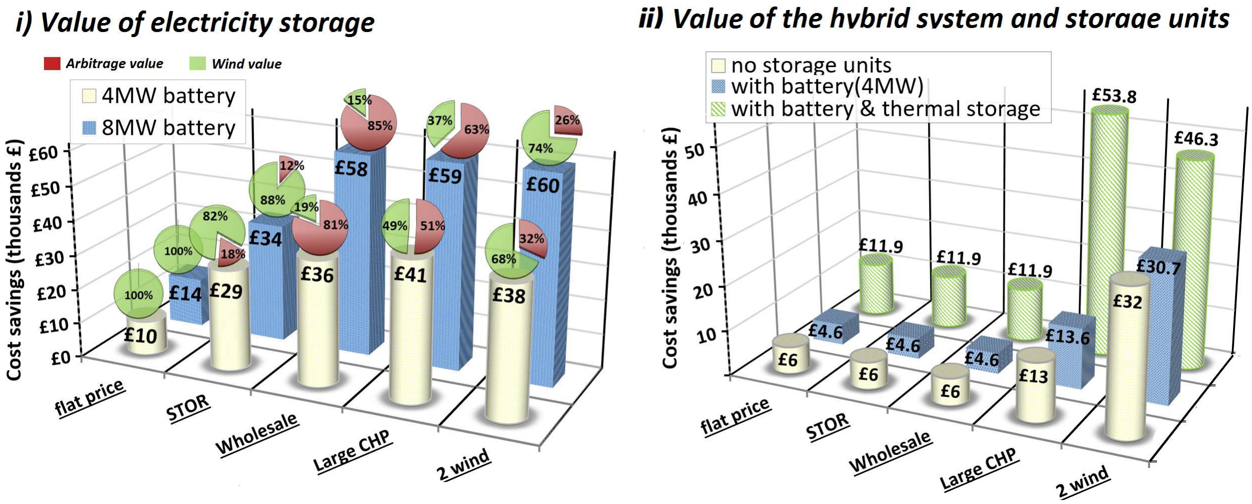

Figure 5 Value of energy sytem configuration as a total annual savings for each case (energy system setting).

Battery value: The introduction of an additional wind turbine increases the value of the battery to 9% and 14% of cost savings for 4MW and 8MW cases respectively. This is due to the fact that without a battery 14.8% of the wind generation is lost while with storage units 4% is unused. Likewise, with a larger CHP, the battery value in GBP savings are about the same as the 2-wind case (see Fig. 5***i*** cost savings in GBP).

Thermal storage value: With an extra wind turbine, the thermal storage increases its wind intake to 7.3% compared to 2.5% in the *base-case*. So, the value of thermal storage slightly increases to 4%. Even though more excess renewable electricity is available, the model still prioritizes first the satisfaction of heat demand so as to minimize heat losses (tank self-discharge loss τ). As for a larger CHP capacity, thermal storage accommodates the CHP heat surplus by charging 42.4% of its stored heat from the CHP compared to 12% in the *base-case*. Hence, this significantly increases the value of thermal storage with gas cost savings up to 15.7%.

Hybrid system value: Table 3 results are calculated under the premise that a hybrid structure is in place. For example, in the reference case (2 wind case without storage), 20.9% of wind surplus goes to heat via the electrical heaters. This value is facilitated by the hybrid system interactions to prevent wind curtailments. Figure 5***ii*** illustrates the total annual cost savings generated by the hybrid system, that is, the difference between the annual cost of a hybrid energy system setting (case profile) and the value of its non-hybrid counterpart. For instance, cost savings for flat price (base-case), STOR and wholesale prices are identical since the use of excess wind for heating requirements is not affected by demand response – the hybrid value remains at 1.5% as in the base-case. Now, since the model prioritizes wind surplus for electricity savings over gas, the introduction of a battery to these cases decreases the value from £6 to 4.6 (in thousands). As for larger DG capacity cases, the value of the hybrid interactions are generated from: (1) the dispatch of excess wind supply (due to larger a base load) for heating demand, and (2) the storage units support on a efficiently use of the CHP by-product energy generation.

Demand response value: Under larger DG capacity cases, the amount of price motivated storage operations decreases since the strategy is to store the supply surplus. The pie charts in Figure 5***i*** indicate that large DG capacity cases increase the proportion of wind to battery (% of charging input) compared to the base-case under wholesale. For example, under a flat price, storage is only used (100% wind charge) to match generation with demand. But load-shifting operations under demand response (wholesale case) came from grid charging (up to 85% arbitrage for 8MW size).

6. Conclusions

The paper analysed the pragmatic benefits of on-site hybrid DG sources for heat and electricity energy systems from the point of view of a large end-user in a smart grid. The paper estimated the value of energy storage units from demand response options and DG sources. Results indicate that storage arbitrage decisions to energy prices doubles the value of electricity storage to 5–7% in costs savings compared to a fixed retail price. Also, storage units play a key role on larger DG capacities, resulting into a battery value of 9–15% reduction in electricity costs and around 15% in gas costs from coupling a large CHP with thermal storage. Acting as a reserve source that supports the grid critical supply periods, the battery response to the STOR signals yields savings of around 5%. This showcases a first concrete study on how to incorporate demand-side storage to balancing markets and a first-hand quantification on the value of batteries for an existing demand response program. Observe that in these results no behavioural changes in demand are inflicted to the end-user, everything is dealt between the smart meter and the battery. This is an important advantage on exploiting smart grid technologies rather than relaying on the predisposition (demand elasticity) of end-users as other studies propose (see Thorsnes et al. 2012). To extend the model and analysis presented in this paper, directions for future research to consider are:

– Add more modelling details on the technical engineering aspects that expose additional storage benefits, such as supporting power quality, stability, voltage and frequency.

– Improve the operation of the CHP. Namely, optimize the CHP by-product generation with the gained flexibility from the battery and thermal storage interactions. In our case study, for example, extend the operational period of the CHP beyond the winter season.

– Consider other incentive options to connect DG sources to the grid. That is, the market design to set a price scheme that encourages end-user participation beneficial to the grid and local utility or suppliers. For example, analysis on business models to apply feed-in tariffs.

– Assess the storage leverage value to other DG technologies (solar PV, biomass, etc.).

– Since the case study is in between a micro grid and medium scale energy producer (or utility scale), we recommend the installation of MW flow batteries (see for example Tapbury Management Ltd 2007), lithium-ion battery (discussion in Parra et al. 2015), and the Tesla utility scale battery prospect (see other types reviewed in Luo et al. 2015). This leads to an important question on whether the savings estimated in this paper could cover the battery cost? According to Ha and Gallagher (2015), flow batteries price projections are around 270£/kWh. Based on our results, the 4MWh battery installed in campus might cover its costs with a lifetime of 20 years (assuming £50K/year of revenue). As this is an estimate, future research should consider detailed financial aspects, other storage benefits, maintenance-operation costs, investments in DG, subsidies, etc.

Appendix

Table 4 Parameters and variables notations

	Decision variables	
Electricity storage	$B_d^{(t)}$	Storage discharge input to electricity demand
	$B_c^{(t)}$	Storage charging intake from electricity supply
Thermal storage	$H_d^{(t)}$	Thermal storage discharge input to heating demand
	$H_c^{(t)}$	Thermal storage charging intake from heating supply
Electrical heaters	$A_{el}^{(t)}$	Electricity used to satisfy heating demand
	State variables	
Electricity storage	$S_b^{(t)}$	Electricity stored in the storage device (Battery)
Thermal storage	$S_h^{(t)}$	Thermal energy stored in the Water tank
Grid supply	$E_{grid}^{(t)}$	Grid consumption to meet electricity demand
Gas boilers	$G_{boiler}^{(t)}$	Natural gas intake for thermal boilers
	Time varying parameters	
Energy demand	$d_e^{(t)}$ & $d_h^{(t)}$	Community electricity and heating demands
Wind turbine	$w^{(t)}$	Wind turbine energy generation from wind power
Energy prices	$p_{el}^{(t)}$ & $p_{gas}^{(t)}$	Electricity and gas prices at time t (GBP/MWh)
	Energy units parameters	
CHP	γ_{chp}	CHP maximum gas intake
	$\eta_{chp\to el}$	CHP conversion rate from gas to electricity
	$\eta_{chp\to he}$	CHP conversion rate from gas to heat
	$G_{chp}^{(t)}$	CHP gas consumption to produce heat/electricity
Battery storage	S_b^{min} & S_b^{max}	Electricity storage lower and upper capacities bounds
	α_b	Electricity storage maximum charging rate
	β_b	Electricity storage maximum discharging rate
	η_{eff}	Battery round-trip efficiency ($\eta_{eff} \in [0,1]$)
Thermal storage	T_h^{min} & T_h^{max}	Minimum and maximum water temperatures in the storage tank
	m	Water mass content for thermal storage (in liters or kg)
	τ	Heat loss coefficient or storage self discharge ($\tau \in [0,1]$)
Gas boiler	η_{boiler}	Conversion rate from gas to heat ($\eta_{boiler} \in [0,1]$)
	γ_{boiler}	Thermal gas boiler maximum capacity
Electrical heaters	$\eta_{el\to he}$	Conversion rate from electricity to heat ($\eta_{el\to he} \in [0,1]$)

Acknowledgments: To the LANCS-initiative for supporting this research. We are also thankful to the Facilities department at Lancaster University for providing technical information and data of the campus energy system. Likewise, a recognition to Mr. Junwei Zeng efforts on an initial study of the energy system.

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