Optimal design and operation of distributed low-carbon energy technologies in commercial buildings

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ABSTRACT

Commercial buildings are large energy consumers and opportunities exist to improve the way they produce and consume electricity, heating and cooling. If energy system integration is feasible, this can lead to significant reductions in energy consumption and emissions. In this context, this work expands on an existing integrated Technology Selection and Operation (TSO) optimisation model for distributed energy systems (DES). The model considers combined heat and power (CHP) and organic Rankine cycle (ORC) engines, absorption chillers, photovoltaic panels and batteries with the aim of guiding decision makers in making attractive investments that are technically feasible and environmentally sound. A retrofit case study of a UK food distribution centre is presented to showcase the benefits and trade-offs that integrated energy systems present by contrasting outcomes when different technologies are considered. Results show that the preferred investment options select a CHP coupled either to an ORC unit or to an absorption chiller. These solutions provide appealing internal rates of return of 28–30% with paybacks within 3.5–3.7 years, while also decarbonising the building by 95–96% (if green gas is used to power the site). Overall, the TSO model provides valuable insights allowing stakeholders to make well-informed decisions when evaluating complex integrated energy systems.

1. Introduction

The implementation of decentralised, also known as distributed energy systems (DES) are increasingly being deployed due to its value in addressing energy issues at a local scale. Increasing energy costs, resource efficiency, energy security, distribution infrastructure constraints as well as sustainability issues are all factors increasing the attractiveness of DES implementation in the built environment [1]. It is estimated that world-wide installed CHP capacity has already exceed 330 GW$_{el}$ and this number is projected to rise [2]. There are many DES alternatives in the market, each one with particular techno-economic features. Some examples are photovoltaic (PV) panels, heat pumps, battery systems, combined heat and power (CHP) units, and organic Rankine cycle (ORC) engines [3]. Having so many options makes it very relevant to understand which is the preferred technology to install in a site and this is not a meaningless task as many factors need to be accounted for; particularly power, heating, and cooling demands. Conducting

a holistic assessment of such systems is paramount to identify the best possible alternative to install according to end-user requirements; otherwise there is a risk of procuring and operating an asset that is not fit for purpose [4].

DES attributes makes them very appealing to a wide range of stakeholders, from investors and building owners up to infrastructure operators; however, that is only if the business case offers sensible returns. Either for new build or retrofit projects it is difficult for decision makers to assess the attractiveness of DES investments as choosing the appropriate technologies, their capacities and operation is a complex endeavour due to the ever changing trends in energy markets and technology development [5]. This circumstance suggests there is a need to develop comprehensive models assessing the impact embedded technologies can have on buildings with the overarching goal of conducting due-diligence on these projects; thus avoiding mistakes in technology selection and operation [6]. In this work energy systems engineering is applied to provide a methodological framework to obtain realistic integrated solutions to complex energy problems, by adopting a systems-based approach, especially at the decision making and planning stage [7].

This paper employs and expands the TSO model presented in

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Refs. [8,9] by unifying the modelling frameworks and thus increasing the scope of technologies and indicators it can evaluate. Given a building, the tool provides decision makers the preferred technology selection and operational strategy for implementation in low-carbon retrofit projects. The data-driven structure of the model allows for these parameters to be updated easily to provide real-world technology selection and not an optimal theoretical capacity. The model considers many elements of complexity being faced in real-world applications such as system integration, energy cost projections, and other valuable on-field information that allows the end-user to appraise a range of technologies in a single platform. The model aims to address the financial, technical, environmental, and grid security issues that commercial building owners face by conducting a multi-year period analysis that allows them to foresee the expected operation of their assets. A case study featuring a real distribution centre building in the UK is used to demonstrate the TSO capabilities and showcase the insights it can provide.

This paper is structured as follows: Section 2 details a brief literature review in this research field. Section 3 presents the modelling framework by describing the problem formulation and how it is mathematically addressed, as well as details on the methodology, data treatment and representation. Section 4 showcases the case study of a distribution centre and discusses salient results. The last section, Section 5, provides concluding remarks.

2. Literature review

Literature concerning optimal integration of distributed systems in terms of design and operation covers a wide range of themes. A core set of publications focus on making sure these projects are properly assessed and that the issues undermining such assessments are comprehended. Both Ref. [10] and Ref. [11] focus on the optimal location and capacity of embedded technologies with the goal of maximising profit while considering its interactions with the infrastructure. These works are complimented by research detailing characteristics that create uncertainty and noise as simplified models can provide biased results [12], making clear that if such DES installations are not sound they will not be able to fulfil their "true" potential [13].

A technology in the centre of most DES literature is combined cooling, heating and power (CCHP), this is because it can supply three forms of energy that are commonly used in buildings. A thorough review of this technology summarising analytical and modelling approaches as well as research gaps can be found in Ref. [14]. Current work in this field is concentrating on developing algorithms that optimise CCHP design with the objective of reducing primary energy use and emissions [15], while also modelling the different components as accurately as possible by employing a balance of heat and mass [16]. Another important aspect in the field concentrates on understanding how to model the non-linear efficiency characteristics of technologies without increasing computational costs; this is a key issue to address in order to make such modelling tools accessible to a wider public [17]. By developing such detailed modelling efforts, it has made feasible to contrast and compare different technologies on an even keel. For example, Markides [5] conducted a broad techno-economic study of various low carbon technologies indicating that it is difficult to make broad statements as to which technology is more attractive than other as the "right" answer depends on multiple criteria and conditions of each case study. Furthermore, externalities such as utility prices, weather, and changes over time in load demand can also influence results considerably.

The optimal sizing and scheduling of integrated distributed systems using an optimisation framework is another key area of DES. These formulations generally employ mixed-integer linear programming (MILP) and allow end-users to evaluate combinations of technologies in the same simulation. A model was presented in Ref. [18] that integrates CHP and backup boiler components with the aim of reducing primary use of energy and environmental impact while also conducting financial evaluations. Similarly, wind, photovoltaic panels, batteries and diesel generators were considered in Ref. [19], emphasising the need to evaluate options by contrasting their levelised cost of energy. On the other hand, there are publications, e.g. Ref. [20], where not only DES technologies are featured but also energy efficiency measures. This type of framework is flexible and allows for multi-objective optimisation where economic and environmental criteria are simultaneously considered and properly traded off. Using this work as a reference, there have been efforts to expand the level of complexity in modelling DES by considering rich data sets that influence the solutions such as electricity cost projects and the impact of weather while combining them with real-world technologies. The TSO model was introduced in Ref. [8] by conducting a multi-objective optimisation to size CHP systems while providing a great level of detail in terms of half-hourly operation for different day types. Furthermore, the TSO approach was employed in Ref. [9] to model the integration of PV and battery systems. Results from the study indicate the financial benefits these technologies can have on the built environment derive mostly from time of use charging strategies and demand response services.

From the works reviewed, a gap was identified for practical simulation tools that allow decision-makers to understand the trade-offs DES solutions offer before committing to such capital-intensive projects. Due to this reason, the TSO modelling framework has been expanded to enable the assessment and comparison of what sometimes seem to be very different alternatives. In this work, ORC and absorption chillers are included and combined with other technologies so more detailed assessments can be made. This paper addresses financial and technical uncertainty that DES investments bring by providing decision-makers with optimal design (i.e. technology selection and capacity) and operation assessments for such systems along with energy security, resource efficiency and environmental indicators. To capture the dynamics of the problem, a mixed-integer linear model has been used to combine numerous complex elements, such as changing energy (electricity, heat and refrigeration) requirements, market-based electricity prices, and distributed technology attributes, *etc.* Due to its adaptability, the TSO model offers many insights that distinguishes it from similar works by:

- Providing a portfolio of existing technologies with both technical and economic parameters which can be easily expanded and assessed for new build or retrofit applications;
- Considering real-life measurements of irradiance levels via weather stations for PV systems;
- Accounting for building attributes that might derail installations such as weight roof limit;
- Incorporating regional real-time pricing data for both electricity imports and exports while also incorporating ancillary service revenue streams (i.e. fast frequency response);
- Taking projections of grid carbon intensity and energy costs to perform a multi-year period optimisation;
- Highlighting key performance indicators (KPIs) that investors and technology experts employ as criteria to support their decision-making process.

3. TSO modelling framework

3.1. Problem formulation

For the TSO model to determine how a distributed energy system is selected, sized and operated it undergoes the following process. Firstly, it provides a baseline scenario by quantifying the energy costs and carbon footprint of a facility assuming it is powered by conventional technologies. Secondly, it searches simultaneously within the distributed technology libraries for the preferred option(s) to install and thirdly, it determines how the selected system can be operated to maximise its value. The optimal solution is identified as the technology configuration that provides the greatest savings against the baseline scenario. As for any model, establishing quality information (i.e. input data) is required before reaching a solution and the model combines a wide set of data before being able to run.

Given:

- Technology libraries from which the model can choose a specific option. Technologies considered are: four PV technologies, four battery storage technologies and small/medium-size CHP units that can be coupled with ORC engines or absorption refrigeration chillers (ARCs). Each library contains technical specifications and associated capital and maintenance costs for each alternative.
- Commercial building parameters:
  - Electricity, heat and refrigeration half-hourly (HH) profiles;
  - Area and roof size of the building to assess available space for technology installation;
  - Location to associate the building with a Distribution Network Operator (DNO) area and therefore identify regional electricity costs influenced by transmission and distribution electricity charges;
  - Location is used to link the site with a nearby Meteorological Office weather station to obtain irradiance levels.
- Irradiance database:
  - Data from Meteorological Office weather stations across the UK;
  - Global Horizontal Irradiance (GHI) hourly metered irradiance over a year.
- Energy and carbon parameters and UK policy projections:
  - Forecasts of HH import/export electricity prices with a 5-year horizon, accounting for all market and regulated related tariffs;
  - Carbon price from the Carbon Reduction Commitment (CRC) initiative;
  - Carbon factor of grid electricity;
  - Feed-in-Tariff (FiT) prices for photovoltaic systems;
  - Revenues from Combined Heat and Power Quality Assurance scheme (CHPQA);
  - Revenue from frequency response ancillary service provision via battery storage.

Determine:

- Technology selection (if no technology is economically viable then none is chosen);
- Rated system capacity;
- HH system operating schedule with a 5-year horizon;
- Project cash-flows, maintenance and operation costs, and other financial indicators such as payback period, Net Present Value (NPV), Internal Rate of Return (IRR), etc.;
- Off-grid capability measured as a security of supply index (SSI);
- Carbon reductions achieved.

Subject to:

- Satisfying electricity, heat and refrigeration demand of the building for all time intervals;
- Technical and financial constraints established by the problem formulation.

The objective function of the optimisation formulation is set to minimise overall project costs for installing the low-carbon asset(s) (i.e. 5-year NPV).

3.2. TSO model structure

The TSO model aims to define the optimal technology selection and operational strategy for onsite energy generation and storage systems in the context of commercial buildings. The energy flows and conversion processes can become complex, particularly when considering trigeneration systems. Fig. 1 illustrates the possible technology configurations and energy vectors considered by the TSO model; highlighting the different streams that can supply electricity, heating, and cooling to a building.

Before identifying the best technological configuration, the model first establishes a benchmark baseline by determining the business-as-usual (BaU) performance. This scenario assumes the site obtains electricity from the grid, heat from a boiler using natural gas and refrigeration from an electric chiller. This step facilitates understanding what would be running costs and carbon footprint from conventional technologies. The model then solves for the optimum technology combination, after which it is possible to contrast the impact of introducing DES. In these simulations, natural gas is substituted for biomethane to maximise the carbon reduction potential from introducing DES.

The TSO optimisation model is data-driven and relies on large databases. These interactions are illustrated in Fig. 2 exemplifying the data streams that are associated with a TSO simulation. In the following sections, further details are given on these key datasets.

3.2.1. Building features and energy loads

Features of the modelled building are used to conduct the optimisation exercise. Building size facilitates assessing the area available for DES, such as roof space for the PVs, or available space for the battery bank, or CHP unit, possibly combined with an ORC engine or an ARC. Constraints such as the roof surface loading co-efficient (i.e. amount of weight it can withstand before requiring reinforcement) are considered as well. Finally, the building's location is used to match the building to a nearby weather station and DNO area hence retrieving the relevant irradiance levels and electricity prices; respectively. Electricity, heat, and refrigeration loads are the main parameters defining a building in the TSO framework. Annual demand data in HH intervals is processed and simplified to determine representative load profiles that ensure a reasonable compilation time. The model employs HH values over 24 day-types (i.e. one typical day for each month: weekday (WD) and weekend (WE)) across a full calendar year. Fig. 3 provides a representation of the WD loads from a food distribution centre that is further analysed in Section 4. Such a representation allows the model to analyse the seasonal load trends and determine the relationship between electricity, heat and cooling consumption, while also quantifying the baseline in terms of cost and carbon emissions in buildings.

3.2.2. Irradiance data

Since the model considers PV as a possible technology choice, solar irradiance data at the relevant location is required for each simulation to produce a reliable PV electricity generation forecast.
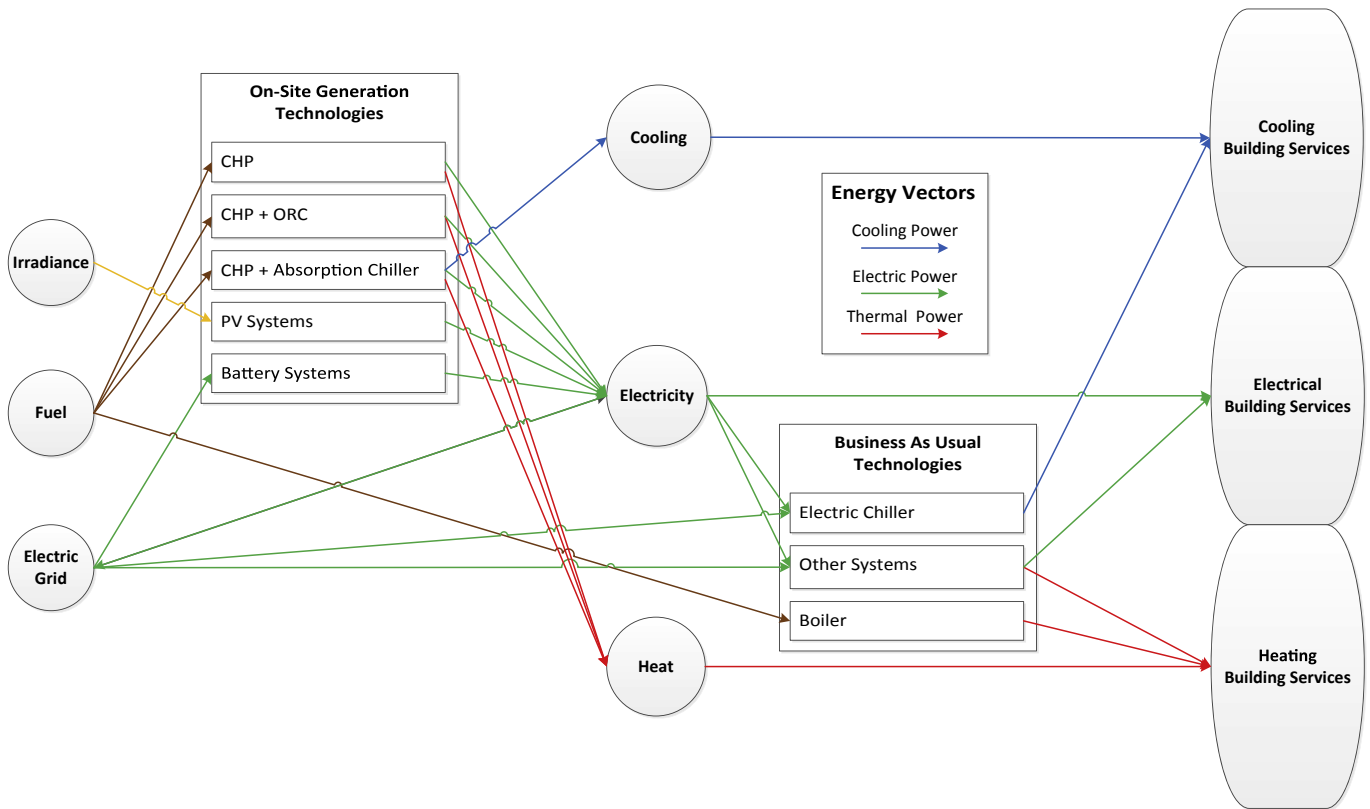
Fig. 1. Structural representation and energy flow options assessed by the TSO model.
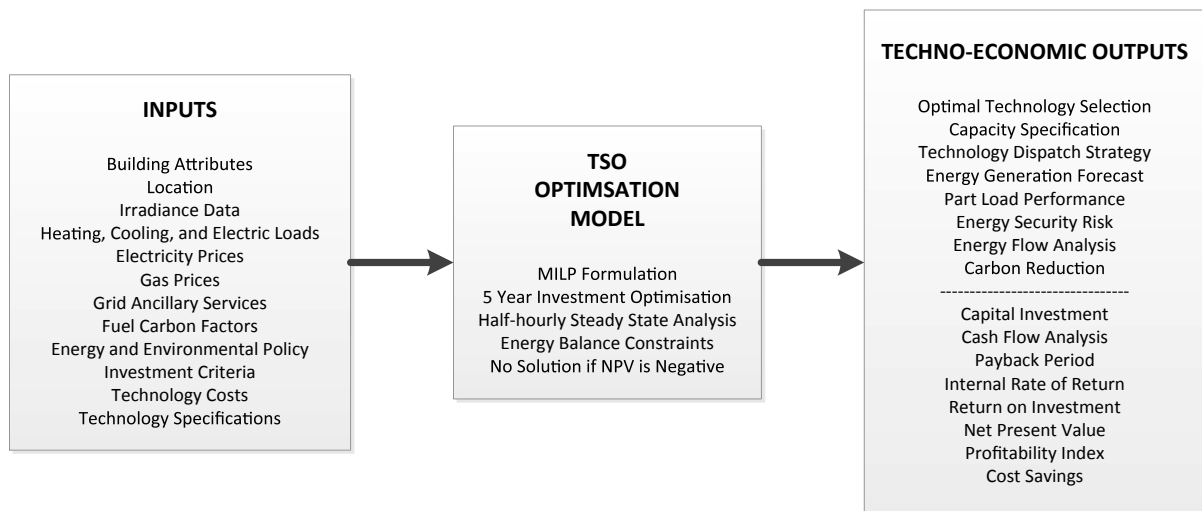

Fig. 2. Schematic description of the data inputs and output components of the TSO model.

UK irradiance data is obtained from the MIDAS database [21], following the methodology described in Ref. [9]. HH values are averaged over 24 day-types to match the TSO framework; an example of monthly WD dataset is illustrated in Fig. 4.

3.2.3. Energy prices and policy

Energy prices with a 5-year horizon, both for electricity and gas, are used to calculate costs and savings associated with energy use in buildings. In the UK there are regional electricity prices for each DNO due to varying transmission and distribution costs. Electricity

and gas prices used in this model are based upon previous cost modelling efforts [22,23]. The open-source methodology consists in a bottom-up model that defines individually all the tariff components and then aggregates them to quantify the cost of a kWh across each half-hour of the day. This granularity facilitates understanding which tariffs influence costs more during different time periods. The TSO model contains all DNO regional HH electricity costs over 24 day-types for 5 years (i.e. 2017–2022). Concerning electricity exports to the grid, it is assumed that only a percentage of the forecasted wholesale price can be obtained when
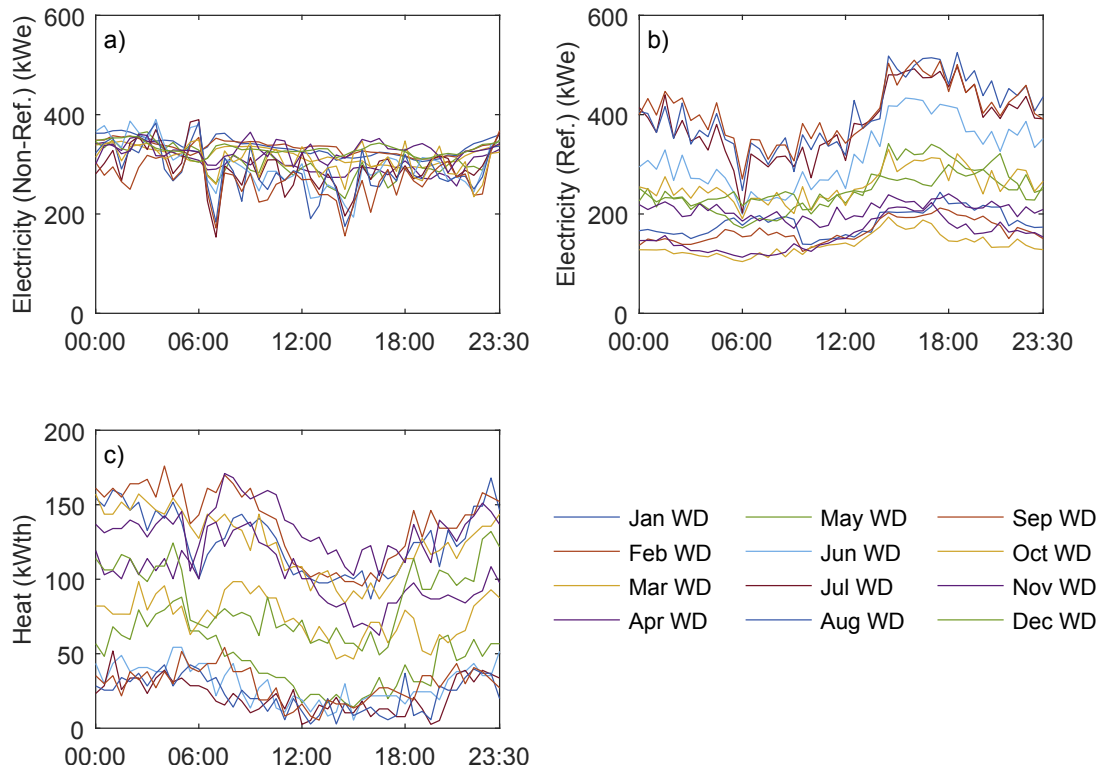
Fig. 3. Day-type HH daily profiles (12) for distribution centre: (a) non-refrigerated electricity demand, (b) electricity powered refrigeration demand, and (c) combined space heating and hot-water demands.

the commodity is sold back to the grid (e.g. 85%). Natural gas prices are determined using industry projections up to year 2022. Fig. 5 provides forecasted 2017–18 electricity prices for DNO Western Power Distribution (WPD) in South West England relevant to the case study presented in Section 4.

Regulation and incentives can impact the attractiveness of DES investments and therefore several policies have been incorporated into the TSO framework to help perform a holistic evaluation. The *Carbon Reduction Commitment (CRC)* is a carbon tax calculated from reported energy use impacting the environment [24,25]. The *Climate Change Levy (CCL)* is an electricity and gas tax used to support the funding of green initiatives [26]. *Feed-in-Tariffs (FiTs)* are subsidies received by owners of low-carbon technologies [27]. Lastly, the *Combined Heat and Power Quality Assurance (CHPQA)* is a government initiative favouring high-quality CHP schemes by providing annual CCL exemptions and Enhanced Capital Allowances (ECA) of the initial investment against taxable profits; that is if the CHPQA quality index (QI) is equal or greater than 105 [28].
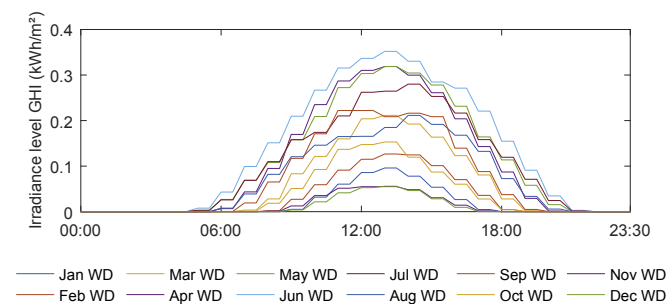
Fig. 4. Solar irradiance over 12 day-types in South West England.

3.2.4. PV and battery technology libraries

Technologies considered by the model contain four PV panel types (mono- and poly-crystalline silicon, Copper Indium Gallium Selenide and Cadmium Telluride) and four battery technologies (Lithium-ion, Lead-acid, Sodium-Sulfur and Vanadium redox). Both PV and battery libraries provide costing and technical specifications as outlined in Fig. 6 and can be consulted in Ref. [9].

It is assumed that maximum electricity yield is obtained from the PV system with respect to the perceived irradiance level at the specified location. Meanwhile, preferred battery operation is subject to changing electricity prices and therefore dependent on seasonality and location [22,23]. The TSO model establishes for each day-type the best management strategy for the battery system to maximise its value. To increase associated revenues, the storage system can stack up purposes by offering several services and therefore opening several revenue streams simultaneously [29,30]. Two possible management strategies are considered by the model:

- *Firm Frequency Response only (FFR)* [30–32]: Provides automatic power response to a change in grid frequency to avoid large deviations from 50 Hz, such response is triggered by the transmission operator. As frequency needs to be monitored on a second by second basis the battery is available to provide frequency response at any moment of the day; therefore, making this service becomes a constant source of revenue.
- *Firm Frequency Response and Time-of-Use bill management (FFR+ToU)*: In this scenario, the battery storage shifts electricity consumption to avoid high electricity costs during peak periods. To do so, the battery follows the behaviour described in Fig. 7. It is mostly charged during the night while keeping a capacity margin to be able to respond to both high/low FFR events. The battery is then fully charged just before the periods of peak
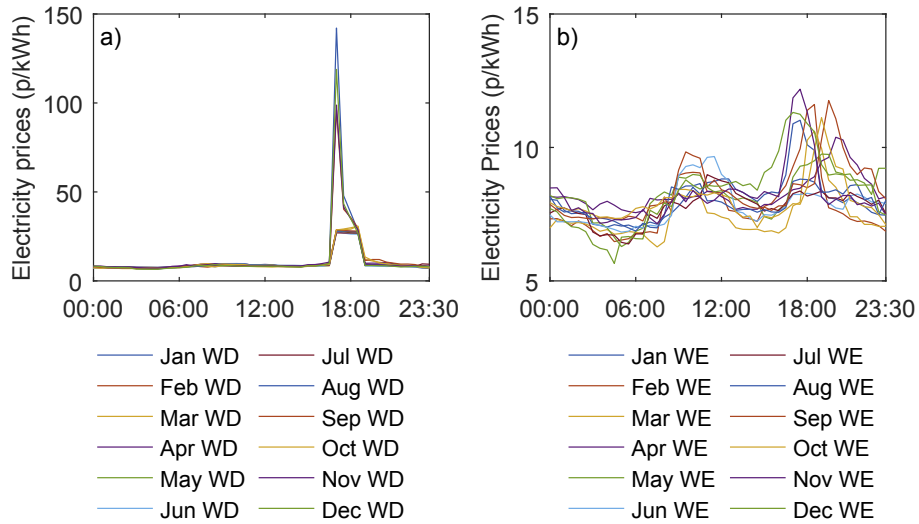
Fig. 5. Forecasted 2017−18 electricity prices for WPD South Western for: (a) week-days, and (b) weekends.
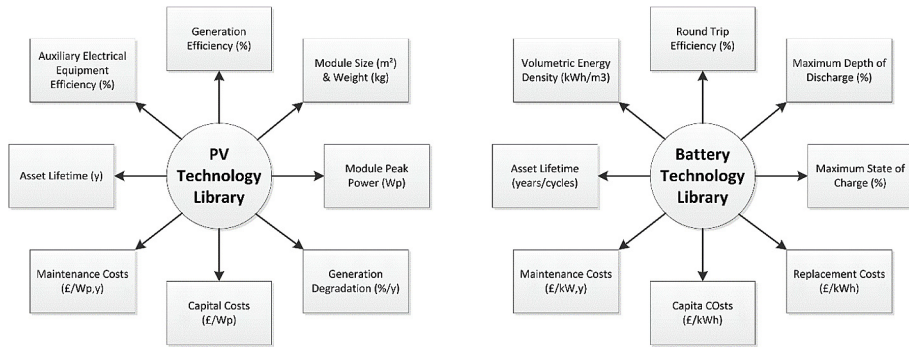

Fig. 6. Representation and parameters of PV and battery libraries used in the TSO framework.

electricity prices (i.e. evenings) to maximise storage capabilities. During the period of charge/discharge around peak hours, frequency response cannot be provided as the capacity margin is no longer available. Once the peak period occurs, the battery is partially charged to enable again the provision of FFR services.

3.2.5. CHP units and arrangements with ORC and chiller technologies

The CHP library database includes 30 gas-engine CHP units with power outputs ranging from 35 kW$_{el}$ to 2.5 MW$_{el}$. These units can be configured as sub-systems if an ORC engine or ARC are deemed adequate. If the optimisation leads to the selection of a CHP, the closest-to-optimal capacity is selected due to the discrete nature of the portfolio. The selected CHP unit can be flexibly operated (i.e. part load) between a 60% and 100% capacity. Assumed engine specifications limit the lower boundary at 60% and thus the CHP is automatically turned off if the preferred operational level falls below this limit. Technical datasheets from manufacturers were used to obtain fuel use, electrical and thermal efficiencies [33]. To allow continuous operation (above 60%), fuel consumption, electricity and heat generation have been linearised using the datasheets. Heat is retrieved from the CHP engine assuming exhaust gases and hot-water streams can be recovered. Initial capital investment is calculated as a combination of unit cost and several ad-hoc commissioning expenses (e.g. engineering works, G59
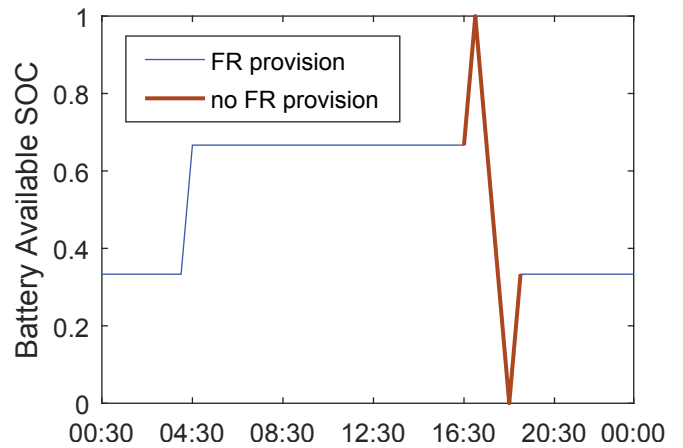

Fig. 7. Battery state of charge behaviour during FFR + ToU days.

procedure, etc.) − see Ref. [8] for further details. Although it must be noted these additional costs can vary depending on the specific circumstances of each project. Overall capital expenditure is annualised and combined with annual maintenance costs, following indicative CHP maintenance costs per kW$_{el}$.

For each CHP unit, the possibility of having an ORC arrangement exists in the TSO framework. Fig. 8(a) shows a CHP engine
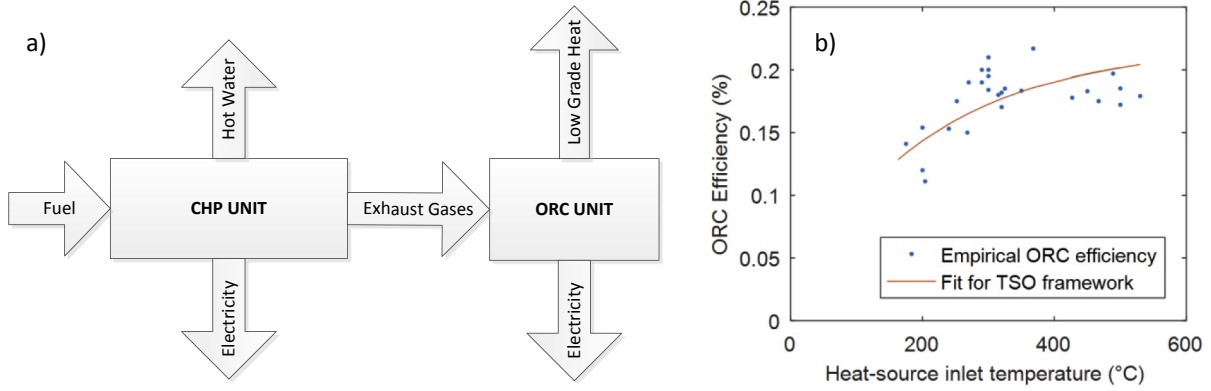
Fig. 8. CHP-ORC model framework: (a) process schematic with energy flows, and (b) ORC engine efficiency curve as a function of heat-source (exhaust gases) inlet temperature from manufacturers' data.

connected to a compatible ORC unit that recovers heat and converts it into electricity. The appropriate ORC unit size is obtained by finding the temperature of the CHP exhaust gases (i.e. between 300 °C and 500 °C depending on size) at distinct operating loads. An empirical ORC engine efficiency curve is obtained using inlet temperature ($\eta_{ORC} = 0.22-0.19 \exp\{-4.79 \times 10^{-3}T\}$). Fig. 8(b)) depicts the ORC generation efficiency curve which is multiplied by the thermal energy available in the flue gases to calculate the ORC power-generation capacity. Based on the CHP engines available in the library, the theoretical ORC units range from 5 kW$_{el}$ to 240 kW$_{el}$. It must be noted that additional project expenses from introducing an ORC engine are accounted in both capital and annual maintenance costs by employing a hybrid of two pricing methodologies showcased in Refs. [34,35].

CHP-ARC combinations are also considered in the TSO framework as converting heat from the CHP engine into cooling to fully or partially supply cooling loads to the building (see Fig. 1). It is assumed that these chillers are single-effect/stage, employ ammonia-water as the working fluid, and are used for refrigerated food applications only, operating at a fixed coefficient of performance (COP) of 0.55. The corresponding energy flow diagram for CHP-ARC configuration is represented in Fig. 9. The ARC library is composed of commercial units and consists of 8 different unit sizes, with cooling capacities ranging from 50 kW$_{th}$ to 1 MW$_{th}$. In this work, a constant cooling output from the chiller is assumed, meaning that it is always operated at its rated capacity when the CHP is running. Therefore, the heat and electricity parasitic load to power the pump of the ARC are met by the CHP even at its lowest part load (i.e. 60% capacity). Costs associated with installing and operating an ARC are incorporated into the project evaluation in the same manner as for ORC engines.

3.3. Mathematical formulation

A MILP approach is employed to represent the TSO optimisation problem in GAMS™. This section summarises key equations that define the problem.

3.3.1. Objective function

The objective function f consists in minimising total 5-year NPV costs:

The objective function is the sum of costs components calculated as 5-year NPVs: the operating cost of the building, C^o, the capital costs of the PV system, $C^{P,C}$, the PV maintenance costs, $C^{P,M}$, the earnings (i.e. negative costs) from FiT, $C^{P,FiT}$, the capital costs for the battery system, $C^{B,C}$, as well as its maintenance costs, $C^{B,M}$, the earnings (i.e. negative costs) from FFR provision, $C^{B,FR}$, the capital costs for the CHP unit (and if selected associated costs from an ORC or ARC), $C^{CHP,C}$, the maintenance costs for this sub-system, $C^{CHP,M}$, and lastly CRC expenses from greenhouse gas emissions over the 5-year period, C^{GHG}.

3.3.2. Energy balances

The TSO model employs three timescale representations: half-hourly settlement periods t (48 per day), day-types d (24 days, two for each calendar month: week-days and weekends) and years y (any 5-year period selected up to 2024). At each time-interval (t,d,y), the electricity, heat and refrigeration flows are balanced, and if necessary, electricity exports and heat rejection occur onsite if the financials are justified.

The electricity demand, e^D, must be equal to electricity imports, e^i, minus electricity exports to the grid, e^e, plus PV production (if chosen), e^P, plus battery discharge (if chosen), e^d, minus battery charging (if chosen), e^c, plus electricity produced by the CHP unit (if chosen), e^{CHP}:

$$e^D_{tdy} = e^i_{tdy} - e^e_{tdy} + e^P_{tdy} + e^d_{tdy} - e^c_{tdy} + e^{CHP}_{tdy} \tag{2}$$

Similarly, the heat demand, h^D_{tdy}, is met by the heat produced by the CHP unit (if chosen), h^{CHP}_{tdy}, plus the heat produced by an auxiliary boiler that is available to top-up demand, h^{AB}_{tdy}:

$$h^D_{tdy} \le h^{CHP}_{tdy} + h^{AB}_{tdy} \tag{3}$$

In case there is excess heat in the system this is dissipated to the atmosphere. Meanwhile, the refrigeration demand, r^D_{tdy}, is balanced by the refrigeration produced by the ARC coupled to the CHP unit (if chosen), r^{ABO}_{tdy}, plus the refrigeration produced by the electric chiller that acts as a buffer, r^{EC}_{tdy}:

$$f = C^o + C^{P,C} + C^{P,M} + C^{P,FiT} + C^{B,C} + C^{B,M} + C^{B,FR} + C^{CHP,C} + C^{CHP,M} + C^{GHG} \tag{1}$$
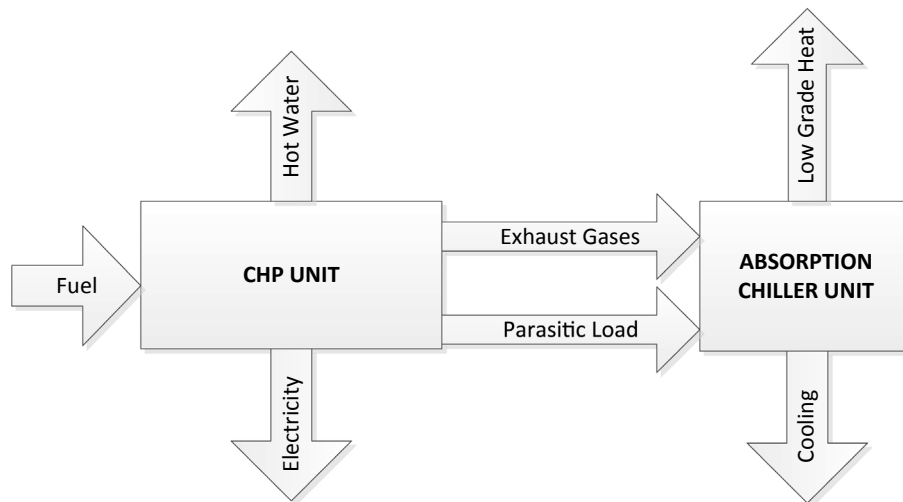
Fig. 9. CHP-ARC model framework with energy flows.

$$r_{tdy}^{D} = r_{tdy}^{ABO} + r_{tdy}^{EC} \tag{4}$$

3.3.3. Key performance indicators

Numerous complementary techno-economic equations are used in the TSO model to quantify and better comprehend changes in system performance from installing DES − please see Ref. [8] and Ref. [9] for further details. Although the TSO model generates many indicators, the following KPIs provide useful insights into energy system analysis:

- *Security of supply index*: Because a power grid black-out can disrupt building business operations, the model calculates the number of hours during the year in which the site is not capable of fully operating off-grid if a DES is installed. It should be noted that this KPI does not account for the likelihood of a grid outage, but just indicates the inability for the site to be self-sufficient. Such type of indicators is to become commonplace in DES studies as organisations consider the impact of disruptions to their operations due to black-outs.
- *Profitability index*: Is an indicator applied in financial analysis for ranking investments as it determines the revenues created per unit of investment. The model calculates the index by summing up the NPV of future cash flows and dividing it by the initial capital cost. A value greater than 1 is a profitable investment and as the KPI increases so does its attractiveness.
- *Dissipated heat*: Reducing heat waste in energy processes is a key goal in sound engineering design. This item is addressed in the model by calculating the amount of heat that is dissipated to atmosphere in CHP installations.
- *CHPQA QI*: Following UK regulatory guidelines on quality assurance for CHPs, the model determines the quality index (QI) of the unit installed. If the value is equal or greater than 105 then the financial incentives explained in Section 3.2.3 are applied into the financial calculations of the TSO model. Taking this KPI into account helps to distinguish which investments can have better returns than others.
- *Load changes*: With the introduction of DES, the energy required from the power grid shifts to other mediums and this can have an impact on peaks and average consumption levels. Similarly, the gas used can increase dramatically if CHPs are installed,

sometimes warranting network reinforcement. The model can display such load changes to better understand the new performance patterns of a building with DES.
- *System resource efficiency*: To better understand the global impacts of applying DES in buildings, an overall energy systems efficiency analysis is performed by considering the sourcing, delivery, conversion, and consumption for the site. The reference benchmark is set by calculating the average efficiency of energy extraction, transfer, and conversion of natural gas and electricity. This KPI provides meaningful information to understand how efficient primary energy resources are being employed with the introduction of DES.

4. Case-study results and discussion

A case-study of an existing food distribution centre (DC) building operated by a UK retailer in South West England is presented to showcase the capabilities of the TSO model.

4.1. Inputs and assumptions

Building attributes and techno-economic characteristics of the DC in its BaU configuration are summarised in Table 1 (for more complimentary data also see Section 3.2). This data comes from empirical meter readings taken onsite every half-hour over the course of a year. The site is powered by electricity from the grid, a natural gas boiler supplies heat for space heating and hot water services, while an electric chiller provides cooling to chilled products. The large area of the site, high irradiance levels, and high operating costs make this building an interesting candidate for DES installation. A representation of the energy loads and solar irradiance associated with the DC building considered in this case study is provided in Section 3.2. Technology capital and maintenance costs have been obtained by engaging with manufacturers and specialists as in previous studies [8,9]. This exercise assumes that green gas (e.g. biomethane) is used as a low carbon fuel in CHP systems to maximise decarbonisation potential, while the BaU solution employs natural gas. Both fuels are assumed to have the same caloric value and same cost over the time frame of the study. It must be noted that the assets already installed in the site are not removed and operate as a back-up; hence, the boiler and electric chiller operate instead of DES if the optimisation suggests it is better to do so.

Table 1
Business-as-usual (BaU) features and annual baseline performance of the DC.

Location	Bristol, UK
GHI (kWh/m^2/y)	1,107
Floor space (m^2)	40,000
Imported electricity demand (GWh$_{el}$/y)	5.02
Peak/average electricity load (kW$_{el}$)	987/575
Non-refrigerated electricity load (GWh$_{el}$/y)	2.74
Refrigerated electricity load (GWh$_{el}$/y)	2.28
Refrigeration cooling load (GWh$_c$/y)[a]	3.92
Natural gas demand (GWh$_{th}$/y)	0.75
Heat demand (GWh$_{th}$/y)[b]	0.67
Peak/average heat load (kW$_{th}$/y)	179/77
Heat-to-power demand ratio	0.13
DNO region	WPD South West
5-year NPV operating costs	£2.26 M
5-year NPV carbon costs	£93 k
5-year CO$_2$ emissions (tonnes)[c]	10 k
5-year NPV total costs	£2.35 M

[a] The COP of the electric chiller is taken to be 1.72.
[b] The efficiency of the boiler is assumed to be 90%.
[c] UK carbon factors (2016) for: grid electricity (0.410 kgCO$_2$(e)/kWh), natural gas (0.184 kgCO$_2$(e)/kWh), and biomethane (0.005 kgCO$_2$(e)/kWh). Source: DEFRA [38].

The TSO model was used to perform five simulations to contrast the trade-offs from diverging DES specifications, such as those that occur when different technologies are compared against each other during the pre-design stage of a project. The range of technologies enabled for each simulation with the goal of minimising total 5-year NPV costs (with an annual depreciation of 8%) is the following:

- Simulation 1: PV and/or battery
- Simulation 2: CHP
- Simulation 3: CHP-ORC
- Simulation 4: CHP-ARC
- Simulation 5: All the above options

4.2. Results

The outputs indicate an optimal solution for all simulations (see Table 2). Only in Simulation 1 is a battery system installed otherwise there is no business case for the technology. PVs are installed in Simulations 1 and 5 although capacities differ drastically; 1.95 MW and 0.15 MW, respectively. Simulation 2 selects the largest CHP capacity at 770 kW$_{el}$, but the remaining simulations prefer a 530 kW$_{el}$ unit. In Simulation 3, the CHP is coupled to a 60 kW$_{el}$ ORC unit, and in Simulations 4 and 5, a 150 kW$_c$ absorption chiller is selected. Table 2 summarises the preferred technology specifications and Table 3 gives the financial KPIs of each project. Table 4 indicates the annual energy flows (i.e. Sankey diagram) that occur for each system configuration with the goal of providing insights regarding the operation and impacts of DES against the BaU scenario, making it clear the net load services remain unchanged but the way they are supplied does. Table 5 denotes the changes experienced by the building's energy system in terms of average and peak power demand, security of supply indices, carbon reduction, and resource efficiency.

Financial results indicate an investment of £1.73 M for the PV and battery system in Simulation 1, a cost higher than those obtained for other CHP-based simulations (ranging from £1.01 to £1.36 M). Accordingly, Simulation 1 has the longest payback at 6.7 years, indicating that without incentives or technology cost reductions, PV and battery systems constitute a questionable investment for most UK organisations that set short payback periods. Furthermore, the technology combination has an annual Security of Supply index of 263 days; meaning that although high in capacity it

does not have sufficient energy to sustain the building off-grid for prolonged periods of the year.

Simulation 2 suggests a stand-alone CHP is a more attractive investment than a PV and battery combination, but falls short to compete with the CHP-based alternatives in other simulations. When considered alone it is desirable to oversize the CHP unit in contrast to Simulations 3 to 5 (from 530 kW$_{el}$ to 770 kW$_{el}$) and operate it at a lower average part load (76% instead of 90%). This solution has the best annual Security of Supply index at 10 days and the greatest decarbonisation potential, although the CHPQA at 104 forsakes financial incentives. Overall, the payback for the stand-alone CHP is 5 years, a figure that is usually accepted in business cases. However, the 5.08 GWh annual dissipated heat is considerable and it warrants investigating if coupling the CHP to technologies that run on thermal power would be a more attractive approach.

Simulations 3 to 5 show that coupling the CHP engine to complementary technologies allows for a better use of excess heat and thus improves significantly their financial evaluation by having payback periods between 3.5 and 3.7 years. This technology integration leads to reducing waste heat by 60–65% and hence improves CHPQA values from 112 up to 128. Although incorporating an ORC or ARC system increases the initial capital investment these are countered by higher NPV savings. The financials are marginally better with an IRR of 28–30%, ROI of 186–207%, and a profitability index between 3.74 and 4.07. It can be seen from Simulations 4 and 5 that the installation of an ARC contributes to a reduction in electricity consumption due to the presence of electric chillers. Consequently, the peak and average demands for the last two simulations are reduced, respectively, by 10% (from 841 kW$_{el}$ to 754 kW$_{el}$) and 15% (from 575 kW$_{el}$ to 487 kW$_{el}$). Although these solutions have a high annual SSI, their winter index is rather low; reflecting robustness at making the building self-sufficient in case the grid fails during extreme cold weather periods (when the UK network is at most strenuous periods) [36]. Simulation 5, which is the most comprehensive in the sense that all technology options are enabled, favours the CHP-ARC configuration complemented by a PV system, however: (i) this configuration is almost identical to the optimal CHP-ARC solution from Simulation 4 without PV; and (ii) arises only as a direct result of the specific optimisation objective selected, which is to minimise operating costs (see Section 3.1) although at a significant investment cost of £1.36 M.

Table 3 can be interpreted differently depending on the priorities set by decision-makers. For instance, a business aiming to obtain the highest IRR, ROI or profitability index would choose solely a CHP arrangement (Simulations 3 or 4). Whereas if the 5-year NPV savings is the main criterion, the CHP-ARC arrangement combined with PV in Simulation 5 would be preferred. Although security of supply has not been allocated an economic value in this study, it is worth mentioning that the solution from Simulation 2 emerges as the most promising if investors prioritise this criterion, and if emissions reduction is paramount, a CHP-only solution leads to higher decarbonisation (>95%) as it is assumed that green gas (e.g. biomethane) is used to fuel these systems. Literature suggests that if natural gas is used instead to power such systems carbon reduction can be as high as 23% [8].

In terms of changes in energy flows from DES, in general security of supply of electricity increases while boiler use becomes nearly non-existent (except in Simulation 1). Also it is clear that there is a risk in becoming overdependent in gas resources to power CHP assets (requiring imports around 10 GWh per year) and such technologies will dissipate large amounts of heat if not designed carefully. ORC and chiller integration with CHPs reduce by more than 60% the amount of heat dissipated against the CHP only solution in Simulation 2. It is also worth noting the ARC in

Table 2
Case study optimal system design results.

Technical Outputs	Simulation 1	Simulation 2	Simulation 3	Simulation 4	Simulation 5
Photovoltaic Technology	Poly-Si	–	–	–	Poly-Si
Number of panels	8051	–	–	–	642
Capacity (kW_p)	1956	–	–	–	156
Capital costs (£)	£1.31 M	–	–	–	£0.11 M
Battery Technology	Lithium-ion	–	–	–	–
Capacity (kW_{el})	781	–	–	–	–
Energy capacity (MWh_{el})	1.17	–	–	–	–
Volume (m^3)	59	–	–	–	–
Capital costs (£)	£0.42 M	–	–	–	–
CHP Arrangement	–	CHP	CHP-ORC	CHP-ARC	CHP-ARC
CHP capacity (kW_{el})	–	770	530	530	530
Average CHP part load(%)	–	76%	92%	89%	87%
Chiller cooling capacity (kW_{th})	–	–	–	150	150
ORC capacity (kW_{el})	–	–	60	–	–
CHPQA QI	–	104	112	127	128
Capital costs (£)	–	£1.01 M	£1.12 M	£1.25 M	£1.25 M
CHP	–	£1.01 M	£0.972 M	£1.007 M	£1.007 M
ORC	–	–	£148 k	–	–
ARC	–	–	–	£243 k	£243 k
Total costs (£)	£1.73 M	£1.01 M	£1.12 M	£1.25 M	£1.36 M

Table 3
Case study financial KPI results.

Financial Outputs	Simulation 1	Simulation 2	Simulation 3	Simulation 4	Simulation 5
5-year NPV BaU costs	−£2.35 M	−£2.35 M	−£2.35 M	−£2.35 M	−£2.35 M
5-year NPV optimised costs	−£2.06 M	−£1.86 M	−£1.92 M	−£1.81 M	−£1.80 M
5-year NPV savings	£293 k	£486 k	£429 k	£543 k	£545 k
15-year NPV savings	£804 k	£1.03 M	£1.17 M	£1.41 M	£1.42 M
Total capital costs	-£1.73 M	-£1.01 M	-£1.12 M	-£1.25 M	-£1.36 M
15-year IRR (%)	13%	20%	29%	30%	28%
15-year ROI (%)	44%	105%	195%	207%	186%
Profitability index	1.49	3.16	4.07	4.07	3.74
Payback period (years)	6.7	5.0	3.7	3.5	3.7

Table 4
2017-18 Annual energy flows (in GWh) for BaU and TSO system case study simulations.

| Energy Flows	BaU	Simulation 1	Simulation 2	Simulation 3	Simulation 4	Simulation 5
Imported electricity	5.02	3.50	≈0	0.26	0.20	0.16
Exported electricity	–	0.37	0.16	0.03	0.02	0.03
Imported natural gas	0.75					
Imported biomethane		0.75	12.57	10.87	10.49	10.25
Gas into boiler	0.75	0.75	0	0	≈0	≈0
Heat from boiler	0.67	0.67	0	0	≈0	≈0
Gas into CHP	–	–	12.57	10.87	10.49	10.25
CHP-based solution electricity output	–	–	5.17	4.79	4.07	3.97
CHP-based solution heat output	–	–	5.77	2.69	2.52	2.40
Dissipated heat	–	0	5.08	2.02	1.84	1.73
Electric chiller demand	2.28	2.28	2.28	2.28	1.51	1.51
Electric chiller cooling supply	3.92	3.92	3.92	3.92	2.61	2.61
ARC cooling supply[a]	–	–	–	–	1.31	1.31
ARC heat intake	–	–	–	–	2.39	2.39
PV generation	–	1.90	–	–	–	0.15
Battery charge	–	0.13	–	–	–	–
Battery discharge	–	0.12	–	–	–	–
Battery losses	–	0.01	–	–	–	–

[a] The COP of absorption chiller is taken as 0.55.

Simulations 4 and 5 reduces conventional chiller demand by 0.77 GWh per year. The electric chiller in this case fulfils only 66% of the cooling requirement, with the rest supplied by the ARC. Overall, if a holistic energy systems efficiency analysis is performed by considering the sourcing, delivery, conversion and consumption of energy for the site, Simulation 1 is identified as having the highest efficiency, while BaU is the least efficient approach. Therefore, results indicate that energy resource efficiency is better with the presence of DES than without.

Table 5
2017-18 Building energy system KPIs of the case study.

Energy Flows	BaU	Simulation 1	Simulation 2	Simulation 3	Simulation 4	Simulation 5
Electrical peak demand (kW$_{el}$)	841	841	841	841	754	754
Electrical average demand (kW$_{el}$)	575	575	575	575	487	487
Annual SSI (days)	365	263	10	128	103	84
Winter SSI (days)	365	107	0	12	4	3
Carbon reduction	N/A	29.9%	99.6%	94.6%	95.7%	96.5%
System resource efficiency[a]	49.4%	68.9%	55.4%	59.9%	62.6%	64.7%

[a] Calculated by taking into account gas network and electricity grid losses and an average sourcing efficiency [1,39]
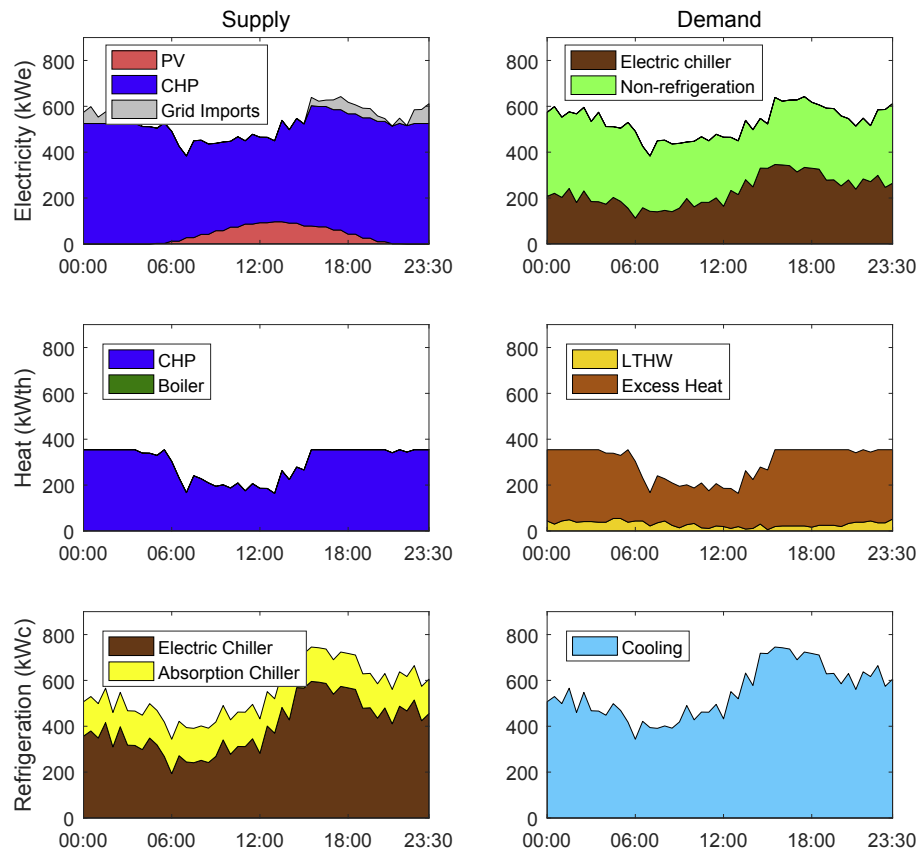
Fig. 10. TSO supply (left) and demand (right) operation for a week-day in June 2017.

4.3. Further discussion of results from simulation 5

To illustrate the level of detail provided by the TSO model, this section presents further insights into the results from Simulation 5 as this offers an attractive business case and considers all technology options leading to an optimal selection of three DES technologies; namely a CHP engine coupled to an absorption chiller plus a PV system. For each day-type, the preferred HH system operation is determined by the TSO model, and an example of a week-day in June is presented in Fig. 10. These results indicate that the electricity is mainly generated by the CHP system, while the PV system provides some additional generation around midday; consequently, electricity imports are not that significant. Even though the optimal system design contains an ARC, a significant part of the building's electricity demand can still be associated with the electric chiller consumption, this is because the capacity of the ARC is not of a significant size for summer time operation. It can also be noticed from Fig. 10 that the CHP is electricity-driven due to the high electricity to gas cost ratio which means it is financially

advantageous to produce power for all time intervals. The caveat of this operating strategy implies a large amount of heat is wasted as the low temperature hot water (LTHW) requirements are not that significant. The energy flows between the CHP and ARC are not captured as the arrangement is considered as a single "black box" (see Fig. 4).

Further analyses can be performed by evaluating the energy flows during other day-types, thereby highlighting different operational strategies over the course of the year. Fig. 11 shows the energy system operation over the course of a week-day in January. It can be observed from Fig. 11 that the PV system will generate less electricity during winter. It is also noteworthy to mention that due to higher grid electricity prices during winter evenings (see Fig. 5), the CHP-ARC arrangement has more incentives to export electricity during this period and is therefore operated at full capacity. Since heat requirements for the building are higher during winter, less excess heat is dissipated. From Figs. 10 and 11, it is seen that the ideal system operation varies based on the month, day-type and time of the day; hence making clear the insights that granular
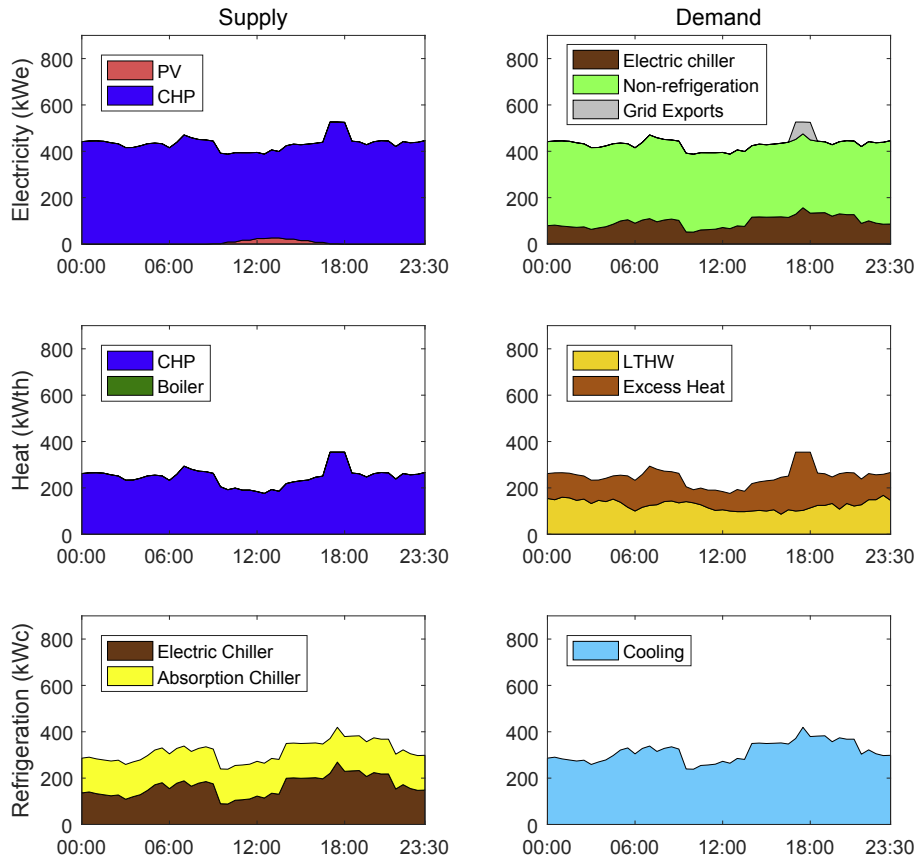
Fig. 11. TSO supply (left) and demand (right) operation for a week-day in January 2017.
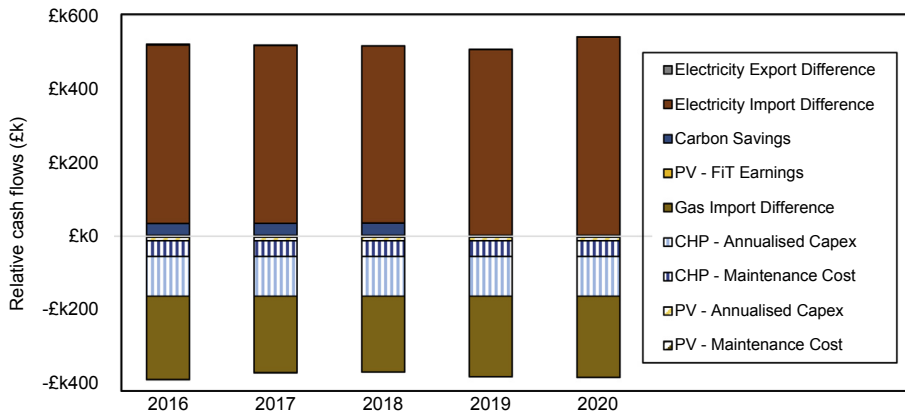

Fig. 12. 5-Year cash flow project breakdown results for Simulation 5. Reviewer #1, Comment #4: Highlights have been modified in response to this comment.

assessments such as this one offers to distributed energy system analysis.

Fig. 12 illustrates multiple positive and negative cash flows associated with the DES investment and thus is key information so decision-makers can make informed decisions. Due to the reduction of electricity imports, the electricity bill is significantly decreased; these savings constitute most of the positive cash flow of the project. These positive cash flows increase over time as electricity costs increase year after year at a higher rate than gas prices; making the avoided costs greater as time transpires. Meanwhile, only for a few hours of the year the system is operated

to export electricity back to the grid, leading to a negligible contribution in the cash balance. As the CRC is not too costly and is to be cancelled in late 2018 [37], carbon cost savings have a minor impact in the financial analysis. The incurred costs related to the project are mostly derived from the increase in gas consumption to drive the CHP-ARC system. The annualised capital expenditure and maintenance costs of the CHP-ARC system has a reasonable impact on the expenses, as opposed to the costs associated with the PV system that are relatively small. Overall, system viability is obtained through a positive annual balance, highlighting that the initial capital expenditure (of £1.36 M) is worth the investment as the

money is recovered after 3.7 years.

5. Conclusion

This paper showcased the capabilities of the TSO model — an integrated energy-systems model that is capable of simultaneously optimising the design, selection and operation of distributed energy technologies in commercial buildings. The model stands out from similar models in the literature as it attempts to evaluate a wide-range of technology investments in real life settings by considering a combination of technical, financial and environmental impacts on the built environment. Such a model is easy to customise and offers decision-makers a detailed assessment of the trade-offs DES investments can have, thus allowing them to make informed decisions before committing to any project. The model prowess relies on an extensive database of DES technology libraries, energy market and location related datasets. Once such information is applied to a building with a specific set of energy requirements, the model can determine the preferred technology configuration to install, its optimal capacity, and ideal operating strategy. A case study of an existing food distribution centre in the UK was used to demonstrate the capabilities of the TSO model for retrofit projects. Results from a series of optimisation simulations for the building assessed suggest that the preferred investment options relate to the installation of technology-integrated solutions in which a CHP engine is coupled either to an ORC engine or an ARC.

Key results and findings indicate that depending on the importance stakeholders and decision-makers give to a variety of KPIs the preferred solution will be subject to change. Simulation insights from the TSO model, which includes multiple technical, financial, and environmental indicators, are particularly valuable in this regard. At the same time, caution should be exercised in attempting to draw generalised conclusions from any assessment, as the context and specifics of similar buildings can vary significantly from site to site. Buildings are impacted differently by various circumstances (e.g. location, thermal envelope, etc.) and therefore careful techno-economic evaluations must be made for each specific case study. Likewise, the proposed technology solutions require further consideration and in-depth analysis; particularly when integrating ORC and ARC systems as the efficiency of such technologies varies according to their design considerations. Since the TSO model is data-driven its effectiveness relies heavily on the quality of data employed (i.e. technology parameters, energy demands and energy prices). Further work should focus on expanding the technology library and refining the integrated system configurations, while also exploring the impact uncertainty brings to such investments since deterministic models do not quantify the level of risk such projects have for decision-makers.

Acknowledgements

Abbreviation list

ARC	Absorption refrigeration chiller
BaU	Business-as-usual
C	Cooling
CCHP	Combined cooling, heating and power
CCL	Climate Change Levy
CHP	Combined heat and power
CHPQA	Combined heat and power quality assurance
COP	Coefficient of performance
CRC	Carbon reduction commitment
DC	Distribution centre
DES	Distributed energy systems
DNO	Distribution network operator
ECA	Enhanced capital allowances
El	Electricity
FiT	Feed-in-Tariff
FFR	Firm Frequency Response
GHI	Global horizontal irradiance
GWh	Giga-watt hour
HH	Half-hourly
IRR	Internal rate of return
KPIs	Key performance indicators
kWh	Kilo-watt hour
kW_p	Kilo-watt peak capacity
LTHW	Low temperature hot water
MIDAS	Met office integrated data archive system
MILP	Mixed-integer linear programming
MWh	Mega-watt hour
N/A	Non-applicable
NPV	Net present value
ORC	Organic Rankine cycle
PV	Photovoltaic
QI	Quality index
ROI	Return on investment
SSI	Security of supply index
th	Thermal
ToU	Time-of-use
TSO	Technology selection and operation
WD	Weekday
WE	Weekend
W_p	Watt peak capacity
WPD	Western power distribution
y	Year

Nomenclature

Indices and sets

t	time intervals
d	day-types
y	years

Parameters

e_{tdy}^D	Electricity demand at time interval t of day type d and year y (kWh)
h_{tdy}^D	Heat demand at time interval t of day type d and year y (kWh)
r_{tdy}^D	Refrigeration demand at time interval t of day type d and year y (kWh)
e_{tdy}^i	Electricity import at time interval t of day type d and year y (kWh)
e_{tdy}^{CHP}	Electricity produced by CHP at time interval t of day type d and year y (kWh)
e_{tdy}^e	Electricity export at time interval t of day type d and year y (kWh)
e_{tdy}^P	Electricity produced by PV at time interval t of day type d and year y (kWh)
e_{tdy}^d	Electricity discharged by the battery at time interval t of day type d and year y (kWh)
e_{tdy}^c	Electricity charge for the battery at time interval t of day type d and year y (kWh)

h_{tdy}^{AB} Heat produced by auxiliary boiler at time interval t of day type d and year y (kWh)

h_{tdy}^{CHP} Heat produced by CHP at time interval t of day type d and year y (kWh)

r_{tdy}^{ABO} Cooling produced by absorption chiller at time interval t of day type d and year y (kWh)

r_{tdy}^{EC} Cooling produced by electric chiller at time interval t of day type d and year y (kWh)

Free variables

$C^{P,FiT}$ NPV (Net Present Value) of FiT earnings (negative costs) for the period (£)

$C^{P,C}$ NPV of PV capital costs for the period (£)

$C^{P,M}$ NPV of PV maintenance costs for the period (£)

$C^{B,FR}$ NPV of FR earnings (negative costs) for the period (£)

$C^{B,C}$ NPV of battery capital costs for the period (£)

$C^{B,M}$ NPV of battery maintenance costs for the period (£)

$C^{CHP,C}$ NPV of CHP costs for the period (£)

$C^{CHP,M}$ NPV of CHP maintenance costs for the period (£)

C^{GHG} NPV of carbon costs for the period (£)

C^o NPV of operating costs for the period (£)

f Objective function, sum of all NPVs (£)

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