Programme Area: Distributed Energy

Project: Macro DE

Title: Description of design methodology and tool effectiveness

Abstract:

This deliverable is number 1 of 3 in Work Package 4. This report details the design methodology developed to allow the systematic design of DE solutions which satisfy the aggregated thermal demands of a ‘characteristic zone’. The design involves selecting which DE generation units (characterised in deliverable 3.2) will comprise the DE solution and specifying the best operating schedule to guarantee minimal capital and operating costs. In addition the report presents the results from the tools application to two test cases used to validate its performance.

Context:

This project quantified the opportunity for Macro level Distributed Energy (DE) across the UK and accelerate the development of appropriate technology by 2020 for the purposes of significant implementation by 2030. The project studied energy demand such as residential accommodation, local services, hospitals, business parks and equipment, and is developing a software methodology to analyse local combinations of sites and technologies. This enabled the design of optimised distributed energy delivery solutions for these areas. The project identified a number of larger scale technology development and demonstration projects for the ETI to consider developing. The findings from this project is now being distilled into our Smart Systems and Heat programme. The ETI acknowledges that the project was undertaken and reports produced by Caterpillar, EDF, and the University of Manchester.

Energy Technologies Institute – Macro Distributed Energy project

Deliverable 4.1

Description of design methodology and tool effectiveness

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Executive Summary

Introduction and objectives

The UK is committed to reduce carbon emissions by up to 30% by 2020 and by up to 80% by 2050 (Climate Change Act, 2008). Distributed Energy (DE) has gained interest over the past few years as a way to maximise the efficient use of fuels to produce electricity and heat near the end users, and therefore to reduce carbon emissions.

The ETI Macro DE project aims at evaluating future opportunities for technology development with respect to Distributed Energy in a rage of sizes up to 50 MWe. The purpose of Work Package 4 (WP4) within the ETI Macro DE project is to develop the methodology for the design of optimised macro DE solutions or energy centres, and to implement this methodology in a software tool.

The methodology is to allow the systematic design of DE solutions which satisfy the aggregated thermal demands of a 'characteristic zone'. The design involves selecting which supply units will comprise the DE solution and specifying the best operating schedule to guarantee minimal capital and operating costs. The lack of software packages in the market with these functionalities made a case for the development of such methodology and software tool (Deliverable 3.1, 2010). This report explains the design methodology developed in Task 4.1 of Work Package 4 and presents results of its initial application to two test cases The methodology has been incorporated in a pre-prototype software tool that will be applied in Task 4.2.

Methodology Development

The technical problem to be solved is the selection of an appropriate set of DE systems which satisfy the heat demands of a 'characteristic zone' with the minimum operating and capital costs. The main variables of the problem are therefore, the number, type and size of the energy supply units (DE systems), as well as their operating schedule (operating mode of each DE system for each time scenario).

To facilitate evaluation of several (20 or more) 'characteristic zones', for a range of scenarios, the design methodology needed to be relatively simple, without unduly compromising accuracy. Twenty-four time scenarios or 'time bands' have been selected to represent the temporal heat and electrical demands of each 'characteristic zone' along the year. Three seasons (Winter, Transition, Summer), two types of day (week day, weekend), and four blocks in a day (morning, day, evening, night) were selected. The validity of these twenty-four time scenarios to accurately reproduce the DE centre performance was evaluated. The performance of the optimised DE solutions, with respect to cost, CO_2 emissions and energy efficiency are reported.

Data for a range of heat and power supply units were prepared in WP3, providing a portfolio of DE systems for the software tool. Data relate to fuel type and cost; installed capital costs; maintenance cost; unit performance (fuel consumption and delivery of heat and/or power at various loads, e.g. 0, 50, 75, 100%); availability; asset life and CO_2 emissions associated with both manufacture and operation. The current portfolio includes the following technologies: CHP engines and turbines, boilers, heat pumps, solar heaters and fuel cells.

Some of the design principles and assumptions considered are summarised below:

- Thermal energy demand of each ‘characteristic zone’ is to be satisfied entirely by the DE solution. Power surplus to the needs of the zone, if any, will be sold as a by-product.
- All the heat produced by the energy centre will be delivered via the district heating network (DHN). The capital cost of the network will be estimated based on the amount of heat delivered and other characteristics of the zone.
- The annual cost of generating heat will be used to assess the performance of DE solutions (i.e. income from heat generation will not be included). Net surplus electricity per time band will be sold at the price applicable to the time band.
- Boilers alone must be able to satisfy peak heat demand, in the case that all CHP units are unavailable

A mixed-integer linear optimisation (MILP) approach is used in the methodology to solve the problem. First, a superset of DE systems for a particular problem is created. Integer variables (binary variables) are defined for each DE system and time scenario. If a supply unit is selected, its binary variable takes the value of one; otherwise the variable is set to zero. Other binary variables and semi-continuous variables, such as equipment part-load and thermal storage capacity, are also defined to establish the operating schedule of the plant. The objective function is to minimise the total cost of heat production (including power sales revenues). Relevant constraints are included, e.g. thermal demand is satisfied in each of the time scenarios under consideration. The optimisation procedure de-selects some equipment and the final set of supply units is a subset of the initial superset.

Thermal storage, i.e. short-term storage of hot water in a tank, can be included by the user to allow CHP units to keep working when thermal demand falls but producing power is beneficial. The thermal storage model must include an expression for the heat balance over a given time period to prevent negative heat flow or continued accumulation. The selected period for closing the energy balance is twenty-four hours. The size of the thermal storage unit is an output of the design methodology.

Software tool architecture and functionalities

The design methodology was implemented in a software environment to create a tool for design and evaluation of DE solutions. The software tool was created in MS Excel®, as it is a user-friendly and familiar environment.

The calculations required for solving the mixed integer linear optimisation problem (MILP) are carried out with the Excel add-in ‘What’s Best!’®. What’s Best! is a compilation of solvers for different optimisation problems (linear, non-linear, mixed-integer, etc.), which can be used directly within Excel® spreadsheets or called from Visual Basic®. Research experience with What's Best! within the Centre for Process Integration, at the University of Manchester, is that it provides a powerful approach for solving large mixed-integer linear problems.

The software is developed for use by researchers carrying out design and sensitivity studies for characteristic zones for the purposes of Task 4.2. In Task 4.3, the research software will be developed further to allow ETI members to use the software for evaluating a limited range of other demand and supply scenarios.

The tool will have two modes: design and simulation. In the 'design mode' a DE solution is designed given the aggregated thermal and electrical demands of a characteristic zone, available DE systems, and other economic parameters such as electrical tariffs and asset life. The results in this mode will include the DE solution configuration and its capital cost, the operating schedule for the best performance, thermal storage requirements, net operating cost of satisfying heat demand, total CO_2 emissions, and consumption of fuels of various types.

In 'simulation mode' the user will be able to simulate and optimise the operation of a specified existing DE solution. In addition, the user could evaluate a DE solution and carry out sensitivity analyses with respect to fuel type, fuel price and power tariffs. In this mode the DE solution is fixed, and the operating modes of the DE systems are optimised in order to maximise the performance of the energy centre in each time band. The results in this mode will include the operating schedule for the best performance, net operating cost of satisfying heat demand, total CO_2 emissions, and consumption of fuels of various types, if applicable. It is assumed that the investment in the equipment has already been made in this case.

The software tool will address feasibility of a design (i.e. the ability to meet the peak thermal demand and satisfy average thermal requirements for all time scenarios) as well as optimality, with respect to a range of performance objectives, subject to relevant constraints, e.g. carbon dioxide emissions.

Results of Initial Application

Initial applications of the pre-prototype software tool were carried out in order to verify the methodology outcomes and illustrate the performance of the software tool.

The first application consisted of a group of sensitivity analyses, given demand data of Harrogate 15, with the aim of evaluating the outcomes of the design tool with respect to expected results. Harrogate 15 provides a representative example of a characteristic zone, such as will be studied in Task 4.2. The following findings were obtained:

- The methodology clearly generates DE solution designs that satisfy the heat demand, represented as average values for 24 time bands, as well as peak thermal demand so as to minimise annual costs.
- Sensitivity studies demonstrated the design methodology responds appropriately to key parameters, namely fuel price, electrical power sales price and DE system capital cost and efficiencies. In all cases, the designs and operating schedules developed are aligned with expectations and reported experience:
    - As fuel price increases, with the same power sales tariff, the generated DE solutions showed lower cogeneration capacity.
    - As the power sales tariff reduces, with the same fuel price, the generated DE solutions showed lower cogeneration capacity.
- Thermal storage is appropriately utilised to increase power generation at times when heat demand is low and to maximise revenue from power sales. Sensitivity studies demonstrated the designed capacity of the thermal storage tank is in agreement with reported experience:
    - For relatively large cogeneration capacity with respect to the average heat demand, a large thermal storage unit is valuable for optimal economic benefits. When the cogeneration capacity is small the ability to offset heat delivery by using stored heat cannot be fully exploited.

- The ability of the tool to design while imposing user-defined constraints on CO_2 emissions has been demonstrated

The second application was the simulation and optimisation of an existing DE centre for which operational demand, supply and design data are available to the consortium. Calculations were carried out firstly to: i) simulate the plant, allowing validation of the simulation models of the tool; ii) establish the accuracy of the time band approach adopted in the methodology; and iii), assess the design and optimisation capabilities of the tool. The findings are summarised below.

i) Simulation: A discrepancy of less than 5% was found between the simulated performance (e.g. fuel consumption) of the existing DE solution and the actual performance. The small discrepancy is thought to be related to: i) differences between the equipment model and real performance, e.g. reported heat to power ratio of 1.27 vs. the 1.24 of the model, ii) differences in the number of days assumed per season vs. the actual ones. Nevertheless, the results demonstrate the validity of the DE solution model to reproduce the outputs or performance of a DE centre from the part-loads of different DE systems in a reduced number of time scenarios.

ii) Investigation of data granularity: The following results were obtained in the study:
   - The sensitivity of simulation and operational optimisation results with respect to the number of time bands supports the simplified approach adopted in this work i.e. the use of relatively few time bands.
   - It was demonstrated that as long as the blocks in a day and the seasons in a year are selected according to sensible parameters, i.e. power sales tariff and thermal demand profile, there is no need to accommodate highly granular demand data.
   - The use of thermal storage, which is the base case for the Macro DE project, significantly reduces the influence of the granularity of the thermal demand profile.
   - The errors associated with using daily averages and seasons selected according to the power sales tariff structure are less than less than 5% of the total annualised costs and less than 10% of the total CO_2 emissions.

iii) Design and optimisation capabilities of the tool:

   The optimised operating schedules developed for the existing DE solution are aligned with expectations and reported experience. For instance, low 'peak power sales tariff to fuel price' ratios reduce the amount of power being exported to the grid with the engine operating only in peak times. High 'peak power sales tariff to fuel price' ratios increase the amount of power exported to the grid with the engine operating normally at full capacity (when power sales tariffs are favourable).

   The proposed methodology also allowed the design of improved DE solutions, compared to the existing centre, by selecting different DE systems from a library of options. Again, the optimal solutions strongly depend on commercial parameters such as power sales and purchase tariffs and fuel prices ('peak power sales tariff to fuel price ratio'), and the purpose of the plant, e.g. whether electrical power is to be sold to the same customers as heat.

Conclusions

A methodology for the systematic design of optimised DE solutions or energy centres has been developed. The effectiveness of the methodology, and of the pre-prototype software tool in which it has been implemented, has been tested through application to a test case representing a characteristic zone and to an existing DE solution.

In the first case, sensitivity studies demonstrated that the design methodology responds appropriately to key parameters such as fuel price, electrical power sales price and DE system capital cost. In all cases, the designs and operating schedules developed are aligned with expectations and reported experience.

In the second case, the DE solution model developed was validated. The performance of the existing solution was reproduced with a discrepancy in fuel consumption and cost of 5% or less. It was also shown that the methodology allows the generation of improved operating schedules for an existing energy centre, and the design of optimal DE solutions by selecting different DE systems from a library of options given the economic parameters of the case.

All these results support the adoption of the simplified approach developed in the methodology (24 time scenarios instead of 8,760 hours in a year). The differences between a time band approach and an hourly approach can be reduced by wise selection of time blocks in a day, seasons in a year (e.g. according to the power sales tariffs), and the use of thermal storage. This conclusion is informing work in WP2 and in future stages of the Macro DE project.

The methodology, and the pre-prototype software tool in which it has been implemented, can be used in future stages of the Macro DE project to allow quantitative assessment of the potential of DE for the UK with respect to its affordability, and its impact on CO_2 emissions and energy security.

Future Work

- In WP4.2, the software tool will be used to design and cost DE solutions for each of the characteristic zones defined in WP2:
    - The overall performance of a DE solution will be evaluated in terms of its economic performance and CO_2 emissions.
    - Several near-best solutions will be identified and ranked to provide insights into the most attractive technologies and operating policies.
    - A methodology for evaluating the technical and economic impact of integrating waste heat, e.g. from industrial sources, will be developed and applied in sensitivity studies.
    - The tool will be used to study the impact of available waste heat for a small number of characteristic zones.
    - The model (currently under development) for estimating the cost of the heat distribution network for a characteristic zone will be incorporated in the design methodology and software tool.
- In WP5 the results for each characteristic zone will be used to assess the UK potential for DE deployment:
    - Sensitivity studies will explore whether macro-scale DE may be commercially viable in 2020.

- Comparison of results against the ‘baseline’ will demonstrate the potential impact on CO_2 abatement.
- Analysis of the types and quantities of fuels consumed will provide insights into energy security.
- Understanding the range of scenarios in which the DE solutions are energy-efficient and affordable will allow the robustness of these solutions to be evaluated.
- In WP5, the tool will be used to assess the potential impact of a range of technology developments to inform technology development priorities outside of the project.

1. Introduction

The UK is committed to reduce carbon emissions by up to 30% by 2020 and by up to 80% by 2050 (Climate Change Act, 2008). In order to meet these targets there must be a significant change in the energy production approach along with a substantive reduction in energy consumption.

Conventionally, electricity is produced in centralised power stations (40-60% efficient in terms of the energy content of the fuel consumed), whereas heat is produced locally by stand alone boilers (80-90% efficient).

Distributed Energy (DE) is an alternative approach which refers to the local generation of heat and/or electricity. DE systems (mainly cogeneration engines or renewable energy conversion devices) could be installed to serve a house or building, or gathered in a DE centre to serve some hundreds of residential and commercial customers. If heat in the form of hot water or steam is also produced and distributed through a District Heating Network (DHN), the energy generation efficiency of DE could be as high as 85 %, representing a potential option for CO_2 emissions reduction.

The ETI Macro DE project aims to evaluate future opportunities for technology development with respect to Distributed Energy, with a focus on electricity generation in the range 100 kWe to 50 MWe. This evaluation will be achieved by: 1) characterizing the UK energy consumption; 2) modelling the technology available to meet energy demand; and 3) developing a software tool capable of designing and costing optimal DE solutions for aggregated heat and electrical demands.

Work Package 4 (WP4), led by the University of Manchester, addresses the third point above, the development of a methodology for the design of optimised macro DE solutions or energy centres, and its implementation in a software tool. The ultimate purpose of the software tool is to allow quantitative assessment of the economic potential of DE and its impact in CO_2 emissions and energy security for the UK.

This document provides a description of the design methodology developed as well as a specification for the pre-prototype software tool implementation and evaluation. The document confirms the alignment of the methodology development with the project objectives, scope and deliverables, and provides supporting information to the project consortium and ETI members about the concepts, principles and assumptions adopted in the design methodology and the evaluation criteria to be used to establish the effectiveness of the pre-prototype software tool.

This deliverable comprises six main sections. Section 2 reviews the methodology objectives and software tool. Section 3 aims to provide a clear and complete description of design approach, allowing independent reproduction of the work; it also provides support for the design assumptions, in the context of the project and stated purposes of the design tool. Section 4 describes the pre-prototype software tool, its functionalities, and the criteria for acceptance. Section 5 presents various scenarios and optimisation results, not only for an existing solution, but for other test cases; these results indicate the accuracy and validity of predicted performances and provide evidence of confidence levels. Finally, Sections 6 and 7 present conclusions and future work.

Appendix A presents an extract of the project contract describing the scope of work for Work Package 4. Appendix B presents a glossary of relevant terms.

2. Objectives of the design methodology

The methodology is to allow the systematic design of specific DE solutions which satisfy the aggregated thermal demands of the several energy users ('sites') comprising a 'characteristic zone'. Design in this context means selecting which DE systems (supply units) comprise the DE solution, specifying their operating schedule (operating mode of each DE system for each time scenario), and assessing the performance of the plant in terms of capital and operating costs and CO_2 emissions. The whole methodology is being implemented in a software tool for use within the project.

Most of the commercial software packages available on the market for heat and power cogeneration are conceived essentially for techno-economic evaluation of a predefined combination of DE systems. This means the user selects beforehand the DE systems that comprise the energy centre, i.e. number, type and capacity (Deliverable 3.1, 2010). Thus, the main difference between the software tool to be developed in this project and existing ones is that the former will allow the conceptual design of an optimal energy centre in a systematic way.

The design methodology is based on optimisation of both structural (number, type and sizes of DE systems) and operational variables (energy output in different time scenarios), to ensure the supply of thermal demands with the minimum associated operating and capital costs.

The methodology accounts for the cost of the heat distribution network given thermal demand data and other user data for the 'characteristic zone'. The detailed design of the heat distribution network, however, is not addressed.

3. Description of the methodology

A full explanation of the methodology developed to design DE solutions is presented in the sections below. The inputs of the problem are first described; then, the design principles and assumptions are listed; and finally the model for design of DE solutions is presented.

3.1. Inputs

3.1.1. Energy demand

To fulfil the project objective to assess the potential for macro-scale DE in the UK, the energy demand of the UK is to be collected and presented in terms of 'characteristic zones' in WP2. Twenty or more 'characteristic zones' will be defined following the clustering of over 7,000 smaller geographical areas into 1,000 to 2,000 actual zones.

The data are to be provided as Excel spreadsheets for each 'characteristic zone' and time scenario with a precise format (shown in Appendix C). Twenty-four time scenarios have been defined – three seasons (Winter, Transition, Summer), two types of day (week day, weekend), and four blocks of time ('time bands') in a day (morning, day, evening, night), as illustrated in Figure E.1. The validity of these twenty-four time scenarios or time bands to accurately represent the annual demand and therefore, the DE centre performance, is discussed in Section 4.2.

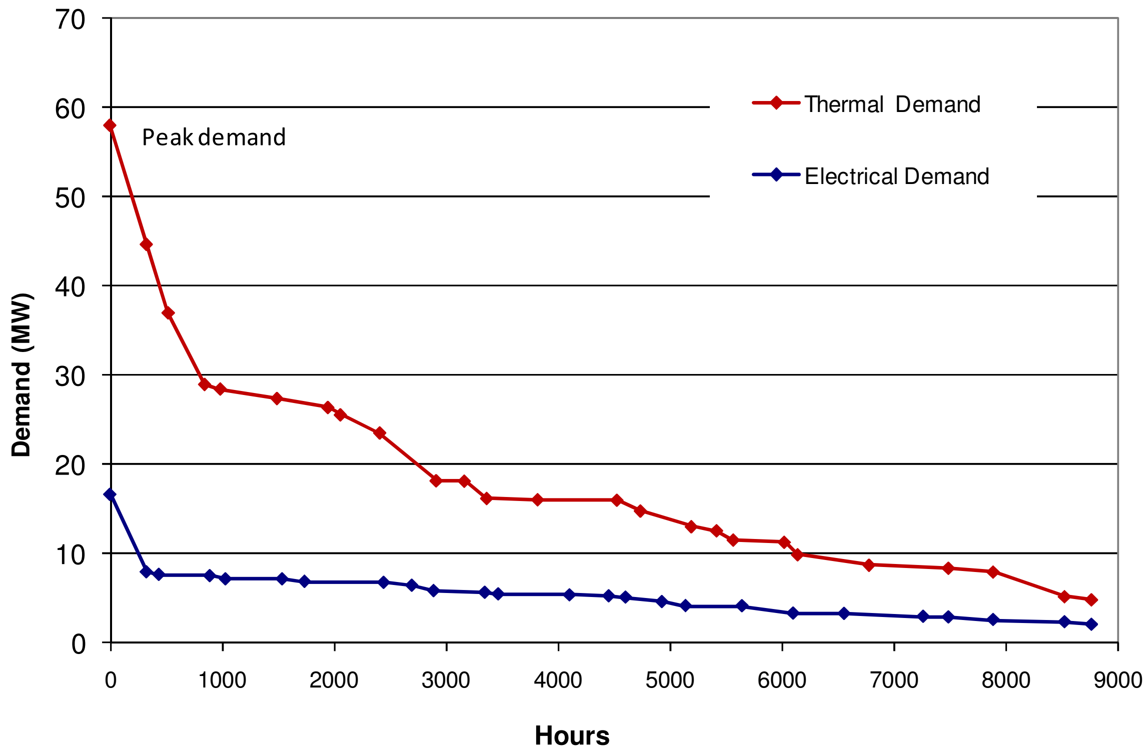

Figure 1 Example of thermal and power demand for a geographic area (Harrogate 15) (Data source: Deliverable 2.0, 2010)

3.1.1. Energy supply

Input data related to the performance and cost of a range of heat and power supply units are being collated in WP3. These data are provided as Excel spreadsheets with a precise format illustrated in Table 1. Each type of equipment or ‘unit type’ has a unique identifier. Data relate to fuel type or energy source; costs (installed capital, maintenance, fuel); equipment size (footprint); unit performance (fuel consumption and delivery of heat and/or power at various loads, e.g. 0, 50, 75, 100%); availability; asset life and CO_2 emissions associated with both manufacture and operation.

Besides engines, gas turbines and fuel cells (known as 'combined heat and power' or CHP units), equipment options include boilers, heat pumps, solar heaters and thermal storage units. Thermal storage is limited to short-term hot water storage; to avoid modelling complexity, a storage period of 24 hours is assumed.

The performance of CHP units, fuel consumption vs. part-load, is treated as linear or piece-wise linear, if applicable. Linear models are developed by least squares regression against available data. In this methodology, part-load (PL) refers to the percentage of heat output from the DE system with respect to its rated (maximum) heat capacity. Figure 2 illustrates the linearisation of the performance data presented in Table 1.

Table 1 Example of DE system model (Gas Engine 1.12 MWe) (Deliverable 3.2, 2010)

General	Model	G3516B LE 1MWe gas engine		
	Total energy output (kWe, kWth)	1,120		
	Fuel type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	1,000		
	Expected lifespan, h (average)	70,000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of technology , %	95		
Operating Costs	Fixed maintenance cost, £/yr	500		
	Variable maintenance cost, £/kWh	0.01		
Performance	CO_2 manufacture, g/kW	59,387		
	Load, %*	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	306	1,120	1,250
	75	240	840	938
	50	169	560	625

*Load defined in terms of electrical output

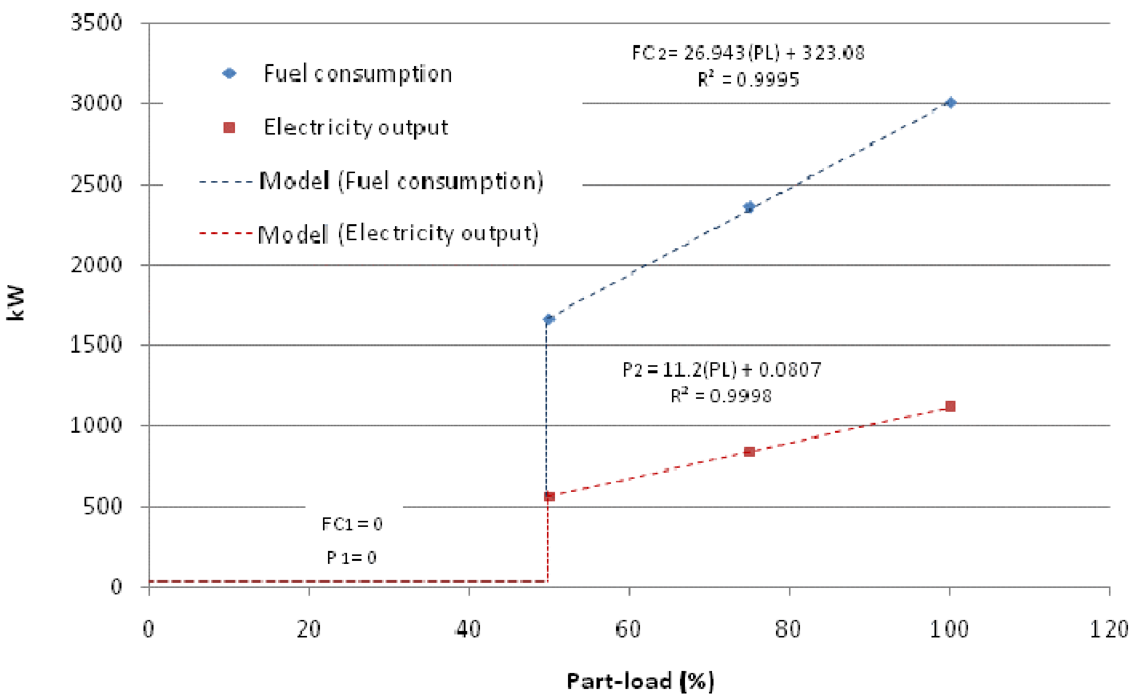

Figure 2 Example of linear model of DE solution performance: fuel consumption with part-load (Gas Engine 1.12 MWe) (Part-load defined in terms of heat output)

3.1.2. Waste heat

Data for available waste heat from specific industrial sources are being gathered in WP2. The data include the type of process, total amount of heat produced annually (MWh), temperature grade and location of the source. It will be assumed waste heat is constantly produced through the year.

The available waste heat per zone will be incorporated in the energy centre design to offset the requirements for heat generation by the energy centre. The minimum temperature accepted by an energy centre is assumed to be 90 ℃. The use of heat pumps to upgrade waste heat available at lower temperatures will be assessed in WP4.2. Assumptions regarding the cost of waste heat and associated capital costs will be defined in WP4.2.

3.1.3. Heat network costs

Cost correlations for heat distribution networks will be provided in WP3 by sub-contractor Mooney Kelly Niras. These are expected to relate installed network cost to peak thermal demand (MW), geographical area (km^2), energy density (MW/km^2) and number of users (i.e. to account for heat exchangers, control units, meters, etc.). These data will be embedded in Excel spreadsheets with a precise format (to be defined in WP4.2).

3.1.4. Primary energy costs

Data relevant to primary energy sources, such as type and cost of fuel, domestic vs. international composition, are incorporated in the supply equipment input data as may be seen in Table 1. For sensitivity studies, these data may be substituted by alternative data (e.g. cost of fuel in 2020).

3.1.5. CO_2 emissions associated with centrally generated power

The design methodology associates with imported electricity CO_2 emissions; in the base case, the CO_2 emissions associated with centrally generated power are 0.485 g/kWh. These emissions are added to those directly produced by the energy centre (Deliverable 1.1, 2010). Conversely, when electricity is exported to the grid, a CO_2 emissions credit is claimed to account for emissions avoided through reduced electricity generation in central power plants; the same emissions rate is used for exported and imported electricity.

The total CO_2 emissions of the zone, including the DE centre emissions and any CO_2 emissions credit or burden, will be compared against the ‘base case’ results where heat demand is supplied by 80%-efficient stand-alone boilers and power demand is met by the grid (Deliverable 1.1, 2010).

Both parameters, credit and burden rates, are inputs to the software tool. Sensitivity studies over future scenarios with a lower-carbon grid may be performed in this way.

3.2. Design principles and assumptions

A key design principle is to satisfy the thermal energy demand of each characteristic zone. Power surplus to the needs of the zone will be sold as a by-product. Any net deficit in power demand will be met by the grid. However, no costs are attributed to electricity distribution within a zone (see Deliverable 1.1).

All the heat produced by the energy centre will be delivered via the district heating network (DHN). The software tool will also cost, but not design, the associated district heating network.

The annual cost of generating heat will be used to assess the performance of DE solutions (i.e. income from heat generation will not be included). Net surplus and net deficit electricity per time band will be sold or bought, respectively, at the price applicable to the time band. In Deliverable 1.1, only ‘peak’ and ‘off-peak’ electricity tariffs are considered, as shown in Table 2. Different tariff structures can be input; these must be aligned with the definition of time bands.

Table 2 Electricity tariffs (Source: Deliverable 1.1, 2010)

Commercial	**Tariff (p/kWh)**
Buying from grid	7 (average price)
Selling to grid (off-peak)	3.62
Selling to grid (peak demand)	4.02

Heat can be stored, as hot water; only short-term storage is considered, i.e. there is no net accumulation of heat over a 24-hour period. Dumping excess heat in the energy centre can be accommodated (although costs of producing the required cooling are not taken into account).

The basis for design calculations will be 2009/2010. Sensitivity studies will address commercial viability in 2020 (Deliverable 1.1, 2010). Further details of design principles and assumptions are described in Appendix D.

3.3. Design methodology

The objective of the design methodology is to design DE solutions in an optimal way. This means selecting an appropriate set of DE systems to satisfy the heat demands of a ‘characteristic zone’ with the minimum operating and capital costs. Thus, the main variables of the problem are the number, type and size of energy supply units (DE systems), as well as their operating loads for each time scenario or band.

Important trade-offs in the design problem relate to the type of primary energy source (e.g. biofuels with higher cost but lower CO_2 emissions); the type and size of DE systems (e.g. smaller units vs. larger units which benefits from economies of scale and improved efficiencies), and the operating schedule of the centre (e.g. revenue derived from surplus electricity generation in peak periods vs. heat storage capacity). The design methodology applies optimisation techniques to account for these trade-offs as well as relevant constraints.

3.3.1. Design-by-optimisation

There are two major approaches in determining the optimal structure of a process and its operating parameters. The first approach fixes some elements in a sequential way and then uses heuristics and/or trial-and-error to identify changes that may lead to improved solutions. This approach is relatively simple to implement but the sequential and non-systematic nature of the decisions can lead to non-optimal designs.

The second approach, which is applied in this work, is based on simultaneous optimisation of structure and operating parameters, using mathematical programming. This strategy requires creation of a superstructure or superset that includes all equipment that can be potentially selected. The equations that rule the performance of each equipment and constraints associated with their operation are incorporated in the optimisation problem. These constraints are designed to ensure that the problem is solved; for instance, the thermal demand is satisfied in each of the time scenarios under consideration. An objective function is defined, e.g. cost minimisation, subject to relevant constraints, e.g. maximum reduction in CO_2 emissions. The optimisation procedure de-selects some equipment and the final structure is a subset of the initial superset. Superset optimisation is a powerful approach when it comes to linear problems because it guarantees that the optimal solution can be found without an iterative procedure (Smith, 2005); therefore, this approach is adopted.

Since discrete models are available for each DE system, a mixed-integer linear programming (MILP) approach is used. In this approach, integer variables (binary variables) are defined for each DE system and time band. If a supply unit is selected, its binary variable takes the value of one (1); otherwise the variable is set to zero (0). Other binary variables and semi-continuous variables, such as equipment part-load and thermal storage capacity, are also defined to establish the operating schedule of the plant. One advantage of the MILP approach is that the whole problem can be optimised simultaneously provided the number of continuous and integer variables and the number of constraints are supported by the software environment used for computation. Note the use of integer variables allows non-linear functions to be modelled as piece-wise linear.

3.3.2. Superset creation

The superset in this methodology consists of a group of DE systems of different technologies (heat only, heat and power, renewable) and capacities. Each of the DE systems modelled in WP3 is called a 'unit type'. In order to allow the selection of more than one DE system of the same type, each 'unit type' is repeated a number of times within the superset. To simplify calculations, the number of repetitions depends on the total heat or electrical demand and the capacity of each unit type.

The superset must be large enough to allow the solver to pick and mix different units to meet thermal demand in a given case. Sufficient numbers of 'unit types' should be present to satisfy the total thermal demand of the zone. In this way the solver can create a DE solution with only one 'unit type' if it proves to be the least costly. Thus, the number of available boilers, solar heaters, and heat pumps of the same type is computed as the aggregated thermal peak demand by the capacity of that 'unit type' (rounded up to the nearest integer):

$$N_{Hmodeli} = \frac{PDth}{Q_{TH\,modeli}} \quad (1)$$

Where,

N_H = number of 'heat only' units

$model_i$ = 'heat unit type' i

$PDth$ = thermal peak demand of the 'zone', MWth

Q_{TH} = thermal capacity, MWth

The number of CHP units, such as engines, turbines and fuel cells, may be set in different ways depending on the user objectives. If the user does not intend to sell excess power, the number of CHP units of the same type should be at least enough to satisfy the aggregated electrical demand of the zone:

$$N_{CHPmodeli} = \frac{PDe}{P_{TCHPmodeli}} \tag{2}$$

Where,
N_{CHP} = number of CHP units (rounded up to the nearest integer)
$model_i$ = 'CHP unit type' i
PDe = electrical power peak demand of the 'zone', MW_e
P_{TCHP} = electrical power capacity, MW_e

If the user intends to sell power, total CHP installed capacity can be higher than the previous case. The decision on the maximum electrical capacity can be left to the user of the software. This work sets as default the maximum amount to 50 MWe:

$$N_{CHPmodeli} = \frac{P_{\max}}{P_{TCHPmodeli}} \tag{3}$$

Where,
N_{CHP} = number of units (CHPs) (rounded up to the nearest integer)
$model_i$ = 'CHP unit type' i
P_{max} = maximum electrical power capacity of an energy centre, MWe
P_{TCHP} = electrical power capacity, MWe

In order to simplify the computation, the user is required to select from a list of models which are to be considered in the energy centre design. Experience may indicate that, for instance, units of 100 kW_{th} capacity for a 'characteristic zone' with a demand of 40 MW_{th} are very unlikely to be selected. Moreover, the maximum number of supply units of the same type is fixed at five (5). This means that the superset will contain a maximum of five units of a 'unit type' for which the capacity is lower than 20% of the peak demand.

3.3.3. DE solution design: Model overview

Appendix E presents a comprehensive explanation of the model, its variables, equations and constraints. The model is summarised below.

The objective function is to minimise the total annualised cost of heat production by the DE solution. This cost is the sum of annualised capital cost, $C_{Tcapital}$, total running costs, C_{Opera}, and net cost of electrical power, C_{Power}:

$$\min\{C_{Total} = C_{Tcapital} + C_{Opera.} - C_{Power}\} \tag{4}$$

If there is a net surplus of power, C_{Power} is positive as income is derived from selling power to the grid; conversely, if there is a net deficit of power, C_{Power} is negative due to the cost of buying power from the grid.

Annualised capital costs are the sum of the capital cost of every DE system by an annualisation factor. The annualisation factor allows the initial investment to be spread across the life time of the assets. A binary variable, y_e, is defined to represent the existence of units (y_e is equal to one (1) if the unit exists and zero (0) if it does not).

When a unit is selected, its capital cost, among other parameters, such as fixed maintenance cost, CO_2 production in manufacture, availability and life time must be included; otherwise these are set to zero.

Annual running costs, or operating costs, comprise two main components: fuel cost, and maintenance costs.

Fuel costs are calculated as the cumulative fuel consumption of every supply unit multiplied by the respective fuel price. Fuel consumption, thermal and power outputs are calculated in different ways depending on the unit model. A binary variable, y_w, is defined for each single unit in order to identify whether it is 'on' or 'off' in each time band (y_w is equal to one (1) if the unit is 'on' and zero (0) if it is 'off'). When a unit is 'on', its part-load (*PL*) can be optimised within a specific range (e.g. minimum load ≤ PL ≤ 100%) and then fuel consumption, thermal and power outputs are calculated. When a unit is 'off', its part-load, thermal output, power output and fuel consumption are all set to zero (refer to Figure 2).

Maintenance costs comprise a variable maintenance cost, which depends on the total output of the unit (e.g. MWh of heat produced), and a fixed maintenance cost per year.

Total revenue (or cost) of electricity sales or purchase is calculated as a cumulative factor in each time period. The energy centre may either sell or buy power, i.e. it cannot do both in the same time band. In order to define whether power is being sold or bought, another binary variable, y_P, is formulated. The difference between the total power produced by the energy centre and the power demand defines the amount of net power being sold or bought. If the user does not intend to satisfy the electrical power demand of the zone, all the electrical generation is to be sold to the grid.

The production of emitted CO_2 by the DE centre is calculated based on the total consumption of each type of fuel plus the annualised emissions associated with the manufacture of the equipment. Together these are defined as 'local CO_2 emissions'. A 'total CO_2 emissions' figure accounts for 'local CO_2 emissions' and the credit or burden associated with power exported to or imported from the grid.

The main constraint of the problem is the system heat balance. Total heat produced within the energy centre must be equal to or larger than the total heat demand. Producing more heat than required is undesirable in some cases because CO_2 emissions will increase; however, this option is available for comparison. When the energy centre is conceived to supply the total power demand of the zone, the system power balance must be satisfied as well.

Thermal storage, i.e. hot water stored in a tank, can be included by the user to allow CHP units to keep working when thermal demand falls but producing power is beneficial. A thermal storage tank is a heat accumulator used for short-term storage of water-based energy. The water content in the tank is constant but its energy content is not. When charging the tank, hot water is supplied to the top of the tank, while the same amount of cold water is extracted from the bottom. When discharging, hot water is extracted from the top, while the same amount of cold water is supplied in the bottom. The hot and cold water are stratified due to differences in density (Petersen and Aagaard, 2004). There is always some mixing of the cold and hot water which forms a layer of non-usable heat (at an intermediate temperature). The height of this layer depends on the temperature range, water flow rate, and design of the tank internals. A well designed tank should have a total usable volume between 85 and 90% (Kandari, 1990).

The difference between the total heat produced by the energy centre and the heat demand in each time band defines the amount of water (heat) being diverted to the thermal storage or extracted from it. A binary variable y_{TS} addresses the operating mode of the thermal storage: charging or discharging.

The thermal storage model must include an expression for the heat balance over a given time period to prevent negative heat flow or continued accumulation. The selected period for closing the energy balance is twenty-four (24) hours. This means the heat accumulator returns to the user-defined baseline (i.e. full, which is the default value, half full, or empty), at the start of each day. The tank cannot exceed its maximum or minimum heat capacity during that period. The main independent variable with this formulation is the maximum heat storage capacity of the tank which can be optimised to minimise operating costs.

To ensure reliable supply of heat, back-up boiler capacity for heat generation is required; it is specified that boilers alone must be able to satisfy peak heat demand in the case that all CHP units are unavailable. Thermal capacity of solar heaters is not considered for back-up because their performance depends on external factors including the weather, location and time of day. If peak demand occurs on a winter evening, for instance, solar heaters will not contribute to satisfy this. Likewise, thermal storage units could not be filled instantly to satisfy the peak if they are half or totally empty; thus, sufficient capacity of fired units such as boilers must be ensured.

4. Pre-prototype software tool

The design methodology is implemented in a software environment to create a tool for design and evaluation of DE solutions. The primary function of the tool is to allow the potential for DE in the UK to be assessed in WP 5.1.

4.1. Software implementation

The methodology for design of DE energy solutions is essentially independent of the software environment, as long as the important numerical issues are addressed effectively.

The approach selected for design of DE solutions involves many integer variables (related to the number of DE systems and the number of time bands), as well as continuous variables. There is also a large number of constraints (e.g. 50% < load < 100%) to take into account. Despite that, key relationships can be represented using linear functions, which makes the problem relatively easy to solve. Given this fact it was decided to create the whole design tool using MS Excel®, as it is a user-friendly and familiar environment that allows an effective optimisation tool as an 'add-in'.

The calculations required for solving the mixed integer linear optimisation problem (MILP) are carried out with the Excel add-in 'What's Best!®, a compilation of solvers for different optimisation problems (linear, non-linear, mixed-integer, etc.), which can be used directly within Excel® spreadsheets or called from Visual Basic®. Research experience with What's Best! within the Centre for Process Integration, at the University of Manchester, is that it provides a powerful approach for solving large mixed-integer linear problems. The advantages of using this environment are several: accelerated software development and debugging; reduced need to develop interfaces between Excel and other environments; availability of local expertise and support.

For the purposes of WP 4.2, the software is developed for use by researchers carrying out design and sensitivity studies for characteristic zones. In Task 4.3, the research software will be developed further to allow ETI members to use the software for evaluating a limited range of other demand and supply scenarios.

4.2. Software tool performance

The outputs of the software tool, applied to characteristic zones, will include:

- cost of satisfying heat demand
- net cost of satisfying power demand when applicable
- cost of installed capital and infrastructure for heat generation and distribution
- operating and maintenance costs of DE solution
- total carbon dioxide emissions, including CO_2 emitted during DE system manufacture
- consumption of fuels of various types

The software will address feasibility of a design (i.e. the ability to meet the peak thermal and satisfy average thermal requirements for all time scenarios) as well as optimality with respect to a range of performance objectives subject to relevant constraints, e.g. capital cost, carbon dioxide emissions.

4.3. Software tool assessment criteria

The effectiveness of the software tool will be assessed with respect to the Macro DE project objectives, namely quantification of the impact on cost, energy efficiency, CO_2 emissions and energy security of deployment of DE throughout the UK. Thus, the software should be judged by whether: i) simulations are valid – i.e. accurate and valid with respect to performance of existing units (where case studies provide evidence of confidence levels for simulations); ii) results of optimisation and scenario studies are aligned with trends established through operator experience and in available published results; and iii) its outputs address the four points below to allow development of a benefits case for DE in WP 5:

- *Design and technology selection* – does the pre-prototype tool design optimal and feasible DE solutions based on aggregated energy demand data and a library of DE system models? Does it select appropriate technologies to satisfy heat demand at minimum cost within constraints imposed on CO_2 generation?
- *Affordability* – does the pre-prototype tool allow the cost of heat production to be computed? Does the tool calculate the cost of DE solutions to allow assessment of their viability?
- *CO_2 Reduction* – does the pre-prototype tool compute the CO_2 emissions of optimum DE solutions to allow assessment of the potential UK benefits with respect to CO_2 emission reduction achieved through deployment of DE systems?
- *Energy Security* – does the pre-prototype tool allow assessment of the potential impact of DE on UK energy security (e.g. fuel mix, contribution of renewable energy)?

4.4. Software tool functionalities

The tool will have two modes: design and simulation. In 'design mode' a DE solution is designed given the aggregated thermal and electrical demands of a characteristic zone, available DE systems, and other economic parameters such as electrical tariffs and asset life. The design is achieved by a mixed integer linear optimisation as explained in previous sections. The results in this mode will include the DE solution configuration, the operating schedule for the best performance, thermal storage requirements, net power purchase or sale, and total CO_2 emissions.

In 'simulation mode' the user will be able to simulate and optimise the operation of a specified existing DE solution. In addition, the user could evaluate a DE solution and carry out sensitivity analyses with respect to fuel type, fuel price and power tariffs. In this mode the DE solution is fixed, and the operating modes of the DE systems may be optimised in order to maximise the performance of the energy centre in each time band. That is, the part-loads will be selected such that i) overall feasibility is maintained (i.e. total the thermal demand is met) and ii) the best performance is achieved (e.g. lowest operating cost). It is assumed that the investment in the equipment has already been made in this case; thus, the objective function for simulation mode is the same that for design mode but excludes the capital costs factor, $C_{Tcapital}$ (equation 4).

5. Initial Applications

Initial applications of the pre-prototype software tool will be carried out in order to verify the methodology outcomes and illustrate the performance of the software tool. Two stages will be developed. The first stage is a group of sensitivity analyses the aim of which is to evaluate the outcomes of the design tool with respect to expected results (for a range of input scenarios). The second stage is the simulation and optimisation of an existing DE solution (energy centre) for which demand, supply and design data are available to the consortium. None of the initial applications will cost the district heating network, as relevant cost metrics are not yet available.

5.1. First stage: Sensitivity analysis of a case study

The purpose of the design methodology in the project is to assess the potential of distributed energy for the UK by applying the methodology to a set of 'characteristic zones'. The first case study applies the methodology to a preliminary example of such a zone. The case study has the following characteristics:

- Energy demand data – based on Harrogate 15 (Deliverable 2.0, 2010) (See Appendix F). Note that week days only are considered in the first-stage analysis. That is, it is assumed that demand is independent of the type of day.
- DE systems – draft models provided by WP3 and literature information (See Appendix F)
- Fuels – only natural gas at a price of 1.13 p/kWh (Deliverable 1.1, 2010), equivalent to £0.111/Nm^3
- Electrical power tariffs – buying tariff: 7 p/kWh; dual selling tariff: 3.62 p/kWh during off-peak hours (7:00 pm – 7:00 am) and 4.02 p/kWh during peak hours (7:00 am – 7:00 pm) (Deliverable 1.1, 2010)
- DHN losses – 10%
- The total electrical power demand is supplied by the centre by either importing power from the grid or producing it in house.

The following sections describe all the analyses carried out to this case study. The DE solutions obtained will be compared against each other and against the 'base case' results (heat supplied by 80% efficiency stand-alone boilers and power supplied by the grid (Deliverable 1.1, 2010)) shown in Table 3.

Table 3 'Base case': basis and results

Base case fuel	Natural Gas (NG)
Stand alone boiler efficiency,%	80.0
Grid Power CO_2 rate production, kg/kWh	0.485
Total fuel consumption, MM* Nm^3/yr	18.795
CO_2 emissions by fuel consumption, t/yr	36,838
CO_2 emissions by power consumption, t/yr	21,313
Total CO_2 emissions, t/yr	58,151
Total fuel cost, MM£/yr	2.086
Total electrical power costs, MM£/yr	3.076
Annual operating costs, MM£/yr	5.162

*MM denotes millions

5.1.1. Scenario 1: Case study with baseline data

The design methodology is applied to generate a DE solution and its optimised operating schedule. Table 4 shows the results. Figure 3 depicts the operating modes of each supply unit in each time scenario considered, as well as total heat and power generation and heat and power demands

(Legend: WD1-4 indicates week day time bands 1 to 4; W, T, S refers to Winter, Transition (i.e. spring and autumn) and Summer, respectively)

Table 4 DE solution design results for baseline (Scenario 1)

Suite selected	Capital cost, MM£	Total thermal capacity, MW
3 Gas Engines of 10 MW (and 2 replacements)	15.00	3 x 11.44
3 Boilers of 20 MW	1.80	3 x 20.00
Total Annualised Capital costs, MM£/yr	1.680	
Total Operating Costs, MM£/yr	0.887	
Annual Costs, MM£/yr	2.567	
Performance		
Total heat production, GWh	162.6	
Total electrical power production, GWh	139.7	
Net electrical power out, GWh	95.8	
Total fuel cost, MM£/yr	4.293	
Total electrical power costs, MM£/yr	-3.686	
Total fuel consumption, MMNm^3/yr	38.672	
Total CO_2 emissions, t/yr	29,494	

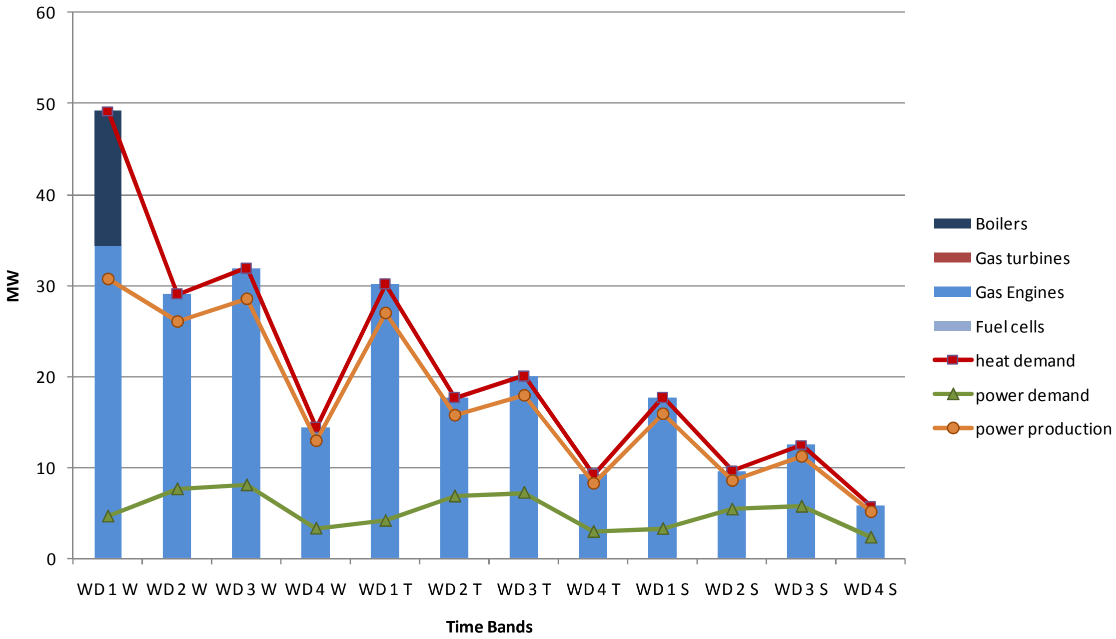

Figure 3 Performance of DE solution (Scenario 1)

The DE solution comprises three gas engines and one operational boiler. The engines operate in a heat-following mode and generate a proportional amount of power which is higher than the electrical power demand of the site. Total annualised costs are MM£ 2.567. Excess power is exported to the grid with annual revenues of MM£ 3.686. The boiler is used when heat demand exceeds the total thermal capacity of the engines (34.32 MWth). The rest of the boilers are selected to satisfy peak demand (58 MWth) and to substitute all the engines in case of a breakdown. Two additional engines are purchased (at the project outset) to replace the original ones at the end of their lifetime of 70,000 hours.

Power production cost is calculated as follows:

$$P_{\cos t} = \frac{C_{oper.}\eta_{electricity}}{P_{out}} \tag{5}$$

where:

P_{cost} = power production cost

$C_{opera.}$ = total operating expenses

$\eta_{electrical}$ = electrical efficiency (power generated per unit of fuel consumed)

P_{out} = total power generated.

In this case the power cost is 1.52 p/kWh at a fuel price of 0.111 £/Nm^3. This figure is lower than the power sales tariff for either off-peak or peak hours. Thus, it is profitable for the energy centre to produce excess power in every time band, including nights. The three engines will run at their maximum possible capacity.

CO_2 emissions decrease by 50% with respect to the ‘base case’. This reduction is due to on-site generation of power and heat in a more efficient way and CO_2 emissions credit claimed from 95.8 GWh of power exported to the grid. If no CO_2 emission credit is claimed, ‘local’ emissions would be 79,959 t/yr. The latter represents a 71% increment with respect to the base case.

5.1.2. Sensitivity analyses

While some of the DE system models are essentially draft models, extrapolated from WP3 data, and while only week day demand profiles are considered, there is value in subjecting this test case to sensitivity studies, to test the design methodology. Various sensitivity analyses are conducted: fuel price variation, power selling price variation, capital costs variation, use of thermal storage and constraints on CO_2 emissions. The results of these are presented in the next sections and serve to demonstrate that the design methodology produces designs and corresponding operating schedules that make sense from a cost, energy and CO_2 perspective.

5.1.2.1. Scenario 2: Fuel price variation

When fuel price increases, relative to the cost of electricity, it is expected the energy centre will produce less power in order to minimise fuel costs. Table 5 and Figure 4 show the results for a fuel price twice the original price, i.e. 0.222 £/Nm^3.

For this DE solution, power production cost is 2.94 p/kWh. With this figure, it is still cost-effective to produce all the power required by the zone and to export some surplus power (38.0 GWh) with revenues of 1.447 MM£/yr. Nevertheless, the DE solution has a lower total CHP installed capacity than in the previous case (one gas engine of 10 MW selected vs. three gas engines in Scenario 1).

A further doubling of fuel price, to 0.444 £/Nm^3, results in a power production cost near 6 p/kWh which does not make profitable to purchase and run an engine in order to produce power in house. In this case, the optimisation tool selects that the grid should supply the entire power demand, while heat demand is supplied solely by boilers. (Table 6 shows these results.)

From this analysis it can be concluded that higher fuel prices, with the same power sales tariff, leads to DE solutions with lower cogeneration capacity. These results are in line with those obtained and documented in related publications (Hongno, Wijun and Ruan, 2008; Fragaki, Andersen and Toke, 2008).

Table 5 DE solution design results for a fuel cost of 0.222 £/Nm^3 (Scenario 2a)

Suite selected	Capital cost, MM£	Total thermal capacity, MW
1 Gas Engine of 10 MW (and 1 replacement)	6.00	1 x 11.44
3 Boilers of 20 MW	1.80	3 x 20.00
Total Annualised Capital costs, MM£/yr	0.780	
Total Operating Costs, MM£/yr	5.547	
Total Annualised Costs, MM£/yr	6.327	
Performance		
Total heat production, GWh	162.6	
Total electrical power production, GWh	82.0	
Net electrical power in/out, GWh	38.0	
Total fuel cost, MM£/yr	6.822	
Total electrical power costs, MM£/yr	-1.447	
Total fuel consumption, MMNm^3/yr	30.730	
Total CO_2 emissions, t/yr	41,863	

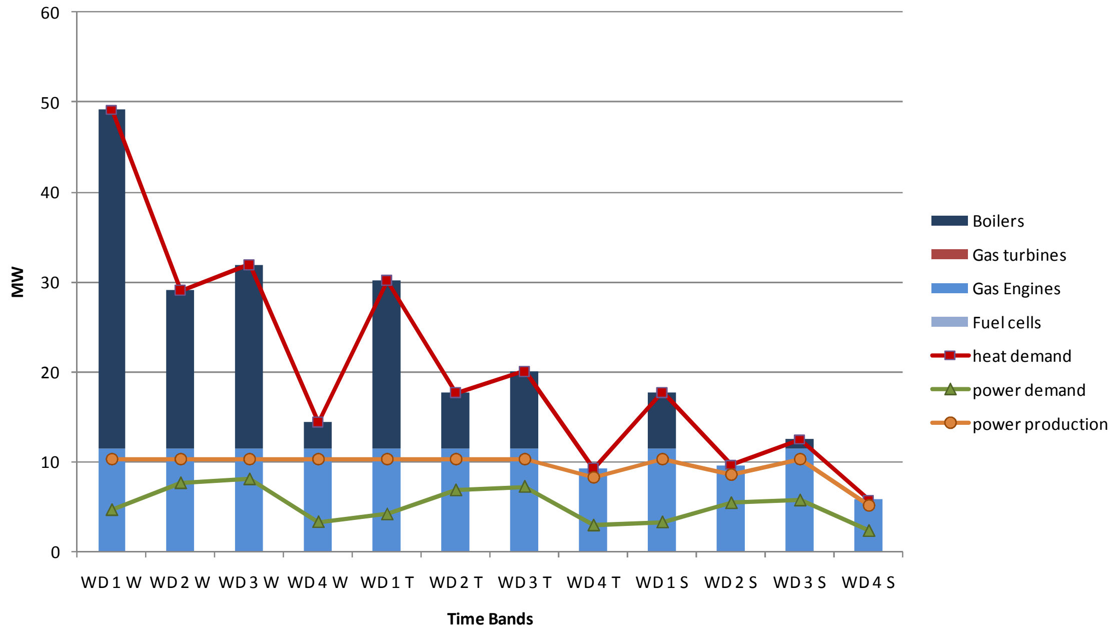

Figure 4 Performance of DE solution for a fuel cost of 0.222 £/Nm^3 (Scenario 2a)

Table 6 DE solution design results for a fuel cost of 0.444 £/Nm^3 (Scenario 2b)

Suite selected	Capital cost, MM£	Total thermal capacity, MW
3 Boilers of 20 MW	1.80	3 x 20.0
Total Annualised Capital costs, MM£/yr	0.180	
Total Operating Costs, MM£/yr	11.731	
Total Annualised Costs, MM£/yr	11.911	
Performance		
Total heat production, GWh	162.6	
Total electrical power production, GWh	0.0	
Net electrical power in/out, GWh	-43.9	
Total fuel cost, MM£/yr	8.639	
Total electrical power costs, MM£/yr	3.076	
Total fuel consumption, MMNm^3/yr	19.457	
Total CO_2 emissions, t/yr	59,479*	

* 10% heat distribution losses

5.1.2.2. Scenario 3: Electrical power sale price variation

When the power sale price is reduced from 3.62 – 4.02 p/kWh (i.e. off-peak – peak) to a much lower tariff, such as zero p/kWh, it is expected the DE solution will not produce power in excess but only what is required by the zone. The fuel price is kept as original, 0.111 £/Nm^3 and thus, the resulting power cost is 1.58 p/kWh, which is well below the actual buying tariff of 7 p/kWh. Results shown in Table 7 and Figure 5 confirm this expectation.

The DE solution comprises two gas engines and two operational boilers. The engines operate in an electrical-following mode and generate a proportional amount of heat which is used to satisfy part of the heat demand. The rest of heat is supplied by the boilers. The third boiler is selected to fulfil peak thermal requirements and as back up capacity. Another engine of 5 MW is purchased at the project outset to replace the original one when its life time ends.

Table 7 DE solution design results for zero power sale prices (Scenario 3)

Suite selected	Capital cost, MM£	Total thermal capacity, MW
1 Gas Engines of 3 MW	1.20	1 x 3.46
1 Gas Engines of 5 MW (and 1 replacement)	3.50	1 x 5.80
3 Boilers of 20 MW	1.80	3 x 20.00
Total Annualised Capital costs, MM£/yr	0.650	
Total Operating Costs, MM£/yr	3.056	
Total Annualised Costs, MM£/yr	3.706	
Performance		
Total heat production, GWh	162.6	
Total electrical power production, GWh	43.9	
Net electrical power in/out, GWh	0.0	
Total fuel cost, MM£/yr	2.846	
Total electrical power costs, MM£/yr	0.000	
Total fuel consumption, MMNm^3/yr	25.643	
Total CO_2 emissions, t/yr	50,340	

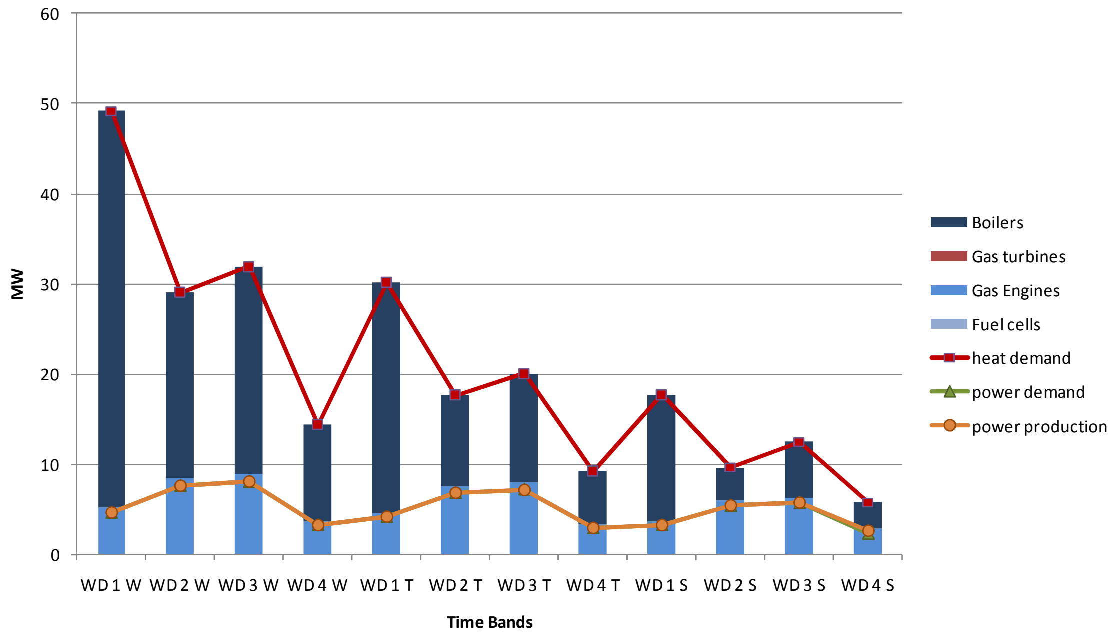

Figure 5 Performance of DE solution for zero electrical power sale prices (Scenario 3)

A net reduction in annual operating costs can be realised relative to the 'base case' (MM£ 5.177 to 3.056 per year) due to the fact that all the power and heat are produced on-site in a more efficient way. CO_2 emissions are 50,340 t, 13% lower than the 'base case' emissions.

It is evident that reducing the power sale price results in DE solutions with lower cogeneration capacity. This trend concurs with our understanding of DE economics, and has also been observed in the published literature (Hongno, Wijun and Ruan, 2008; Fragaki, Andersen and Toke, 2008).

5.1.2.3. *Scenario 4: Equipment capital cost variation*

When the capital cost of a particular technology is very high, it is expected the software will not select units of this kind. In Scenario 4, the capital cost of gas engines is increased twenty times (to 10,000 £/kW) in order to test the software under this condition and its ability to select other technologies. Fuel price and power sales tariffs are kept as in the first case, 0.111 £/Nm^3 and 3.62 – 4.02 p/kWh (off-peak – peak), respectively. Table 8 and Figure 6 show the results.

Table 8 DE solution results for increased capital cost of gas engines (Scenario 4)

Suite selected	Capital cost, MM£	Total thermal capacity, MW
1 Gas Turbine, 3 MW	2.70	1 x 7.75
1 Gas Turbine, 5 MW (and 1 replacement)	7.00	1 x 2.25
3 Boilers of 20 MW	1.80	3 x 20.00
Total Annualised Capital costs, MM£/yr	1.150	
Total Operating Costs, MM£/yr	3.021	
Total Annualised Costs, MM£/yr	4.171	
Performance		
Total heat production, GWh	162.6	
Total electrical power production, GWh	54.5	
Net electrical power in/out, GWh	10.5	
Total fuel cost, MM£/yr	3.150	
Total electrical power costs, MM£/yr	-0.358	
Total fuel consumption, MMNm^3/yr	28.376	
Total annual CO_2 emissions, t/yr	56,336	

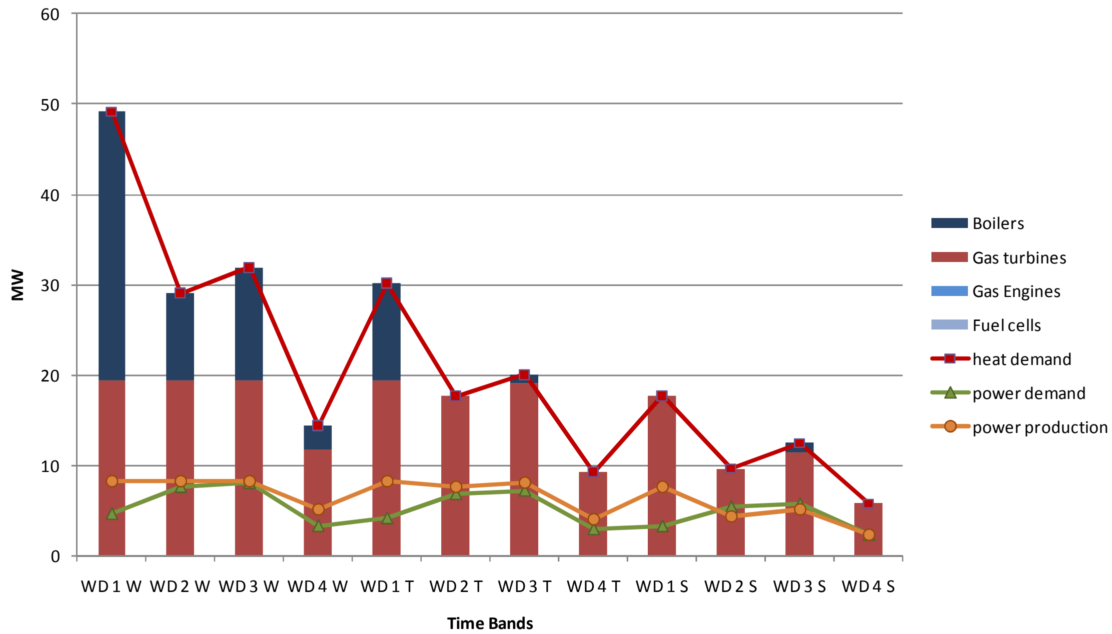

Figure 6 Performance of DE solution for increased gas engines capital cost (Scenario 4)

By comparing the results for Scenarios 1 and 4, it can be seen that no gas engines are selected. One gas turbine of 3 MWe and one of 5 MWe are included instead. The DE solution has a lower total electrical power production capacity (8 MWe) than in Scenario 1 (3 of 10 MWe) where cheaper gas engines were considered. The selection of DE systems (i.e. gas turbines) with lower electrical ratings can be understood with respect to their higher heat-to-power ratios (2:1 compared to 1.1:1 for gas engines) and lower turndown efficiencies (70% efficiency at 50% part-load compared with 90% efficiency at 50% part-load in gas engines) (Orlando, 1998). The selection of larger turbines would require higher system turndowns, leading to higher fuel consumption.

Total annualised costs of this scenario are 60% higher than in Scenario 1. Less surplus power is exported to the grid (only 10% of that in Scenario 1) which translates as less income to offset fuel consumption cost. The same reasoning explains why CO_2 emissions double, compared to Scenario 1 (56,336 t/yr vs. 29,494 t/yr). The emissions reduction which can be claimed is much less than in Scenario 1.

These design results are in agreement with expectations that high cost DE systems will be avoided in design, that high operating efficiencies will be sought and that revenue from power production is significant in the DE solution economic performance.

5.1.2.4. Scenario 5: Inclusion of a thermal storage unit

As explained in Section 2.3.3, the methodology is conceived in such way that the optimal thermal storage capacity will be given as part of the results. Table 9 and Figure 7 show the DE solution design results with the same data as Scenario 1 but including a thermal storage unit (TSU). The energy balance over the thermal storage unit is over a 24-hour period.

Table 9 DE solution design results with thermal storage unit (Scenario 5a)

Suite selected	Capital cost, MM£	Total thermal capacity	
1 Gas Engines of 5 MW	1.75	1 x 5.80 MW	
2 Gas Engines of 10 MW (& 2 replacements)	12.00	2 x 11.44 MW	
3 Boilers of 20 MW	1.80	3 x 20.00 MW	
Thermal Storage	0.59	100 MWh	2,519 m^3
Total Annualised Capital costs, MM£/yr	1.614		
Total Operating Costs, MM£/yr	0.820		
Total Annualised Costs, MM£/yr	2.434		
Performance			
Total heat production, GWh	163.0		
Total electrical power production, GWh	144.2		
Net electrical power in/out, GWh	100.3		
Total fuel cost, MM£/yr	4.369		
Total electrical power costs, MM£/yr	-3.860		
Total fuel consumption, $MMNm^3/yr$	39.359		
Total annual CO_2 emissions, t/yr	28,638		

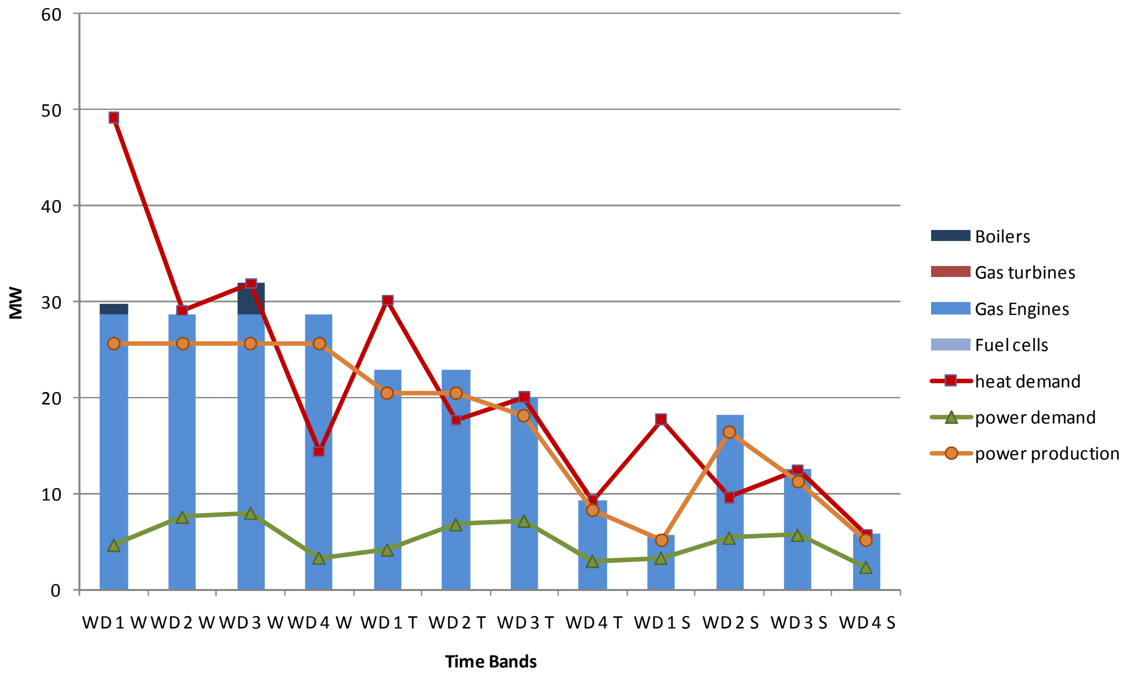

Figure 7 Performance of case study with thermal storage unit (Scenario 5a)

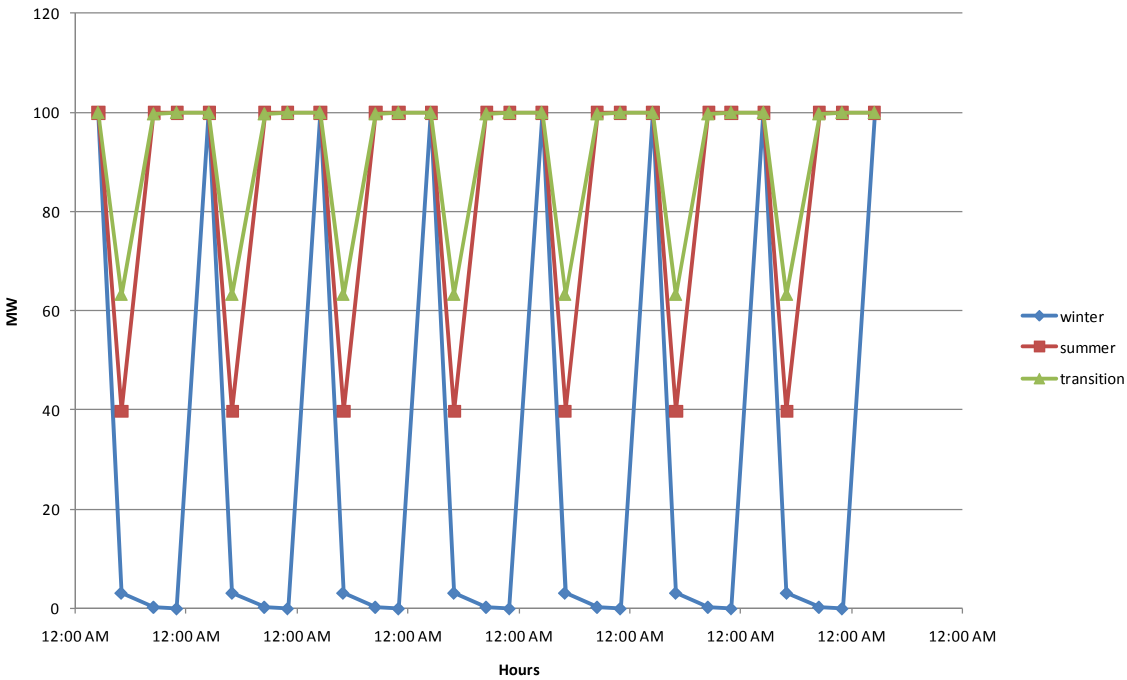

Figure 8 Thermal storage unit operation for one week (all 'week days') of different seasons (Scenario 5a)

The solution comprises three gas engines, two of 10 MW and one of 5 MW, and one operational boiler of 20 MW. Although the cogeneration capacity is lower than in Scenario 1 (where three gas engines of 10 MW are selected), CHP supply units maintain their power production when thermal demand decreases due to the presence of the TSU, e.g. in time band WD4W. This allows power exports to the grid of 100.3 GWh, which translates as a 5% net reduction in total annualised costs with respect to Scenario 1.

Figure 8 shows the operating schedule of the TSU for a week of different seasons (Winter, Summer and Transition). For instance, in Winter the thermal storage discharges almost completely within the first time band of the day (05:00 to 09:59) at a rate of 20 MW to supply 97 MWh; during the next two time bands there is no use of the thermal storage unit. Then the energy content in the tank increases until is fully charged at the end of the last time band (22:00 to 04:59). It is profitable charging the tank during the night because the off-peak sales tariff (3.62 p/kWh) is still higher than the power production cost of 1.52 p/kWh. The thermal storage unit is then used to provide heat at periods of high demand (e.g. mornings in Winter and Transition seasons).

In order to further assess the methodology, a higher fuel price with a lower cogeneration capacity is considered. The results for a fuel price of 0.222 £/Nm^3 and a TSU are shown in Table 10. Only one gas engine of 10 MWe capacity is selected. Since the maximum rate of power production (10 MW) is most of the time below the heat demand rate (see Figure 4), the capacity of the TSU is only 15 MWh (15% of previous case). There is just a slight reduction in annual costs with respect to Scenario 2 (see Table 5); thus, it may be concluded that the TSU does not bring significant benefits in this scenario.

Table 10 DE solution design results with fuel cost of 0.222 £/Nm^3 and TSU (Scenario 5b)

Suite selected	Capital cost, MM£	Total thermal capacity, MW	
1 Gas Engine of 10 MW (and 1 replacement)	6.00	1 x 11.44	
3 Boilers of 20 MW	1.80	3 x 20.00	
Thermal Storage	0.08	15 MWh	380 m^3
Total Annualised Capital costs, MM£/yr	0.789		
Total Operating Costs, MM£/yr	5.534		
Total Annualised Costs, MM£/yr	6.323		
Performance			
Total heat production, GWh	163.0		
Total electrical power production, GWh	86.4		
Net electrical power in/out, GWh	42.4		
Total fuel cost, MM£/yr	6.965		
Total electrical power costs, MM£/yr	-1.610		
Total fuel consumption, MMNm^3/yr	31.373		
Total annual CO_2 emissions, t/yr	41,003		

When the cogeneration capacity is small, the ability to offset heat delivery by using the TSU cannot be fully exploited. For relatively large cogeneration capacity, and considering the fluctuation in power sale prices, a larger storage tank is valuable for optimal economic benefits. These findings are aligned with those reported in the published literature (Fragaki, Andersen & Toke, 2008; Hongno, Wijun and Ruan, 2008).

5.1.2.5. Scenario 6: Constraint on CO_2 emissions

One of the functionalities of the software tool is that it can design DE solutions with a constraint on the total CO_2 emissions per year. This constraint is imposed as a percentage of the 'base case' CO_2 emissions. Note that in Scenario 6, no CO_2 emissions credit is claimed from power exported to the grid in order to assess the potential of DE to reduce 'local' emissions from energy consumption within a characteristic zone (refer to

Scenario 1). It is expected the DE solution will select low-carbon technologies when CO_2 emissions are constrained.

Table 11 and Figure 9 show the results obtained with 90% of the 'base case' CO_2 emissions as a constraint. The total power generation capacity of the DE solution is 10 MWe, whereas for Scenario 1, where no CO_2 constraint is imposed, it is 30 MWe. In Scenario 6, the engine produces as much power and heat as possible within the CO_2 limit. Boilers provide the rest of the heat required. Surplus power (8.8 GWh) is exported to the grid with annual revenues of MM£ 0.328, less than a third of that in Scenario 1. This translates as a 37% net increment in total annualised costs.

Table 11 DE solution design results with 90% of 'base case' emissions (Scenario 6)

Suite selected	Capital cost, MM£	Total thermal capacity, MW
1 Gas Engines of 10 MW (and 1 replacement)	6.00	1 x 11.44
3 Boilers of 20 MW	1.80	3 x 20.00
Total Annualised Capital costs, MM£/yr	0.780	
Total Operating Costs, MM£/yr	2.753	
Annual Costs, MM£/yr	3.533	
Total heat production, GWh	162.6	
Total electrical power production, GWh	52.8	
Net electrical power out, GWh	8.8	
Total fuel cost, MM£/yr	2.965	
Total electrical power costs, MM£/yr	-0.328	
Total fuel consumption, MMNm^3/yr	26.713	
Annual CO_2 emissions, t/yr	52,439	

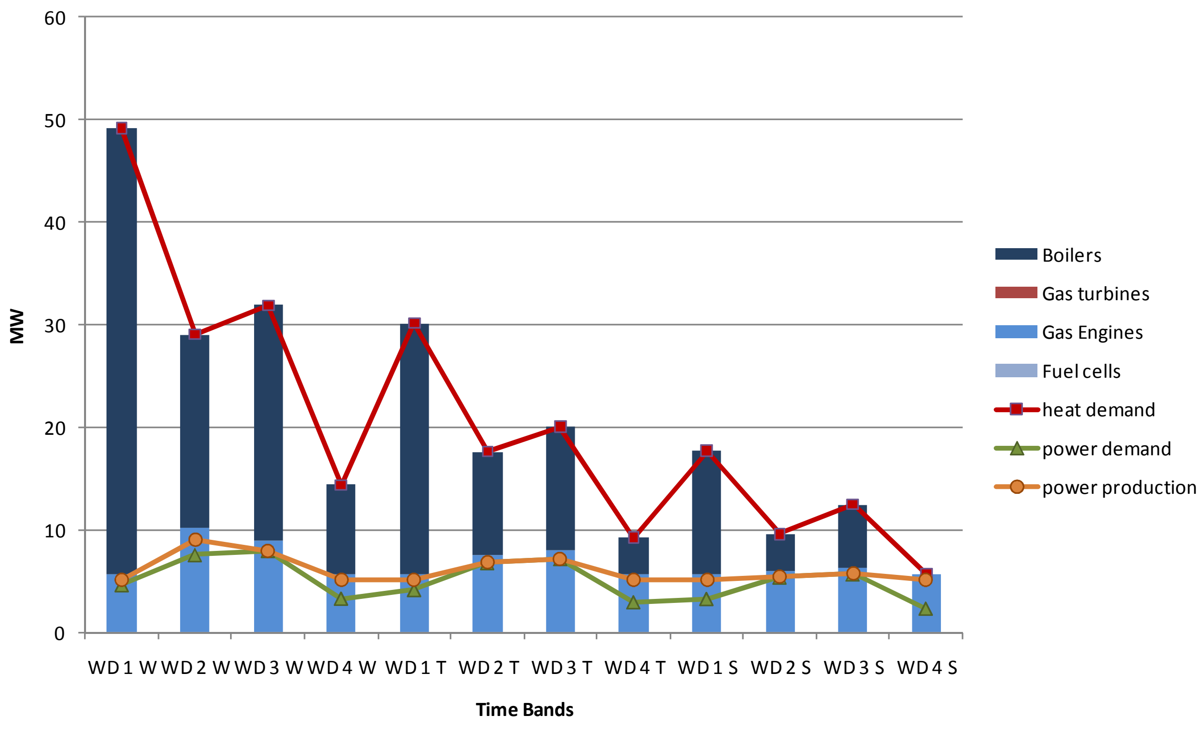

Figure 9 DE solution design results with CO_2 constraint (90% of 'base case' emissions)

A lower 'local' CO_2 emissions limit will result in DE solutions with less power generation until the point where all the power demand is satisfied by on-site generation and there is no surplus power. The results of this case are equal to the results of Scenario 3 where CO_2 emission reduction is 86% of the 'base case' (see Table 7). CO_2 is generated at a rate of 0.246 t/MWh of total useful energy produced, i.e. power plus heat.

If no change is made in the superset, setting lower CO_2 constraints will make the problem infeasible because i) reducing power production means importing power from the grid at a higher rate of CO_2 generation (0.485 t/MWh compared to 0.246 t/MWh), and ii) there is insufficient capacity of zero-carbon technologies to substitute fuel-fired units while satisfying, at the same time, the total heat demand. Only one model of solar heaters, with a very low capacity (0.1 MWth), is considered. It is evident that the demand data of this case study (a peak thermal demand of more than 50 MW) does not suit the range of zero-carbon technologies available in the current library.

5.1.3. Initial applications: First stage – Summary

The new design methodology has been applied to a representative test case to explore the performance of the design approach for a range of scenarios. The methodology clearly generates DE solution designs that satisfy the heat demand, represented as average values for 24 time bands as well as peak thermal demand, so as to minimise annual costs. The design methodology satisfactorily incorporates sufficient back-up heat generation capacity to substitute all CHP units, in case of simultaneous failure. The design methodology provides information about operating schedules, as well as annual performance with respect to heat and power generation, cost and CO_2 emissions. Thermal storage is appropriately utilised to reduce heat and power generation at times when heat demand is high and to maximise revenue from power sales.

Sensitivity studies demonstrate that the design methodology responds appropriately to key parameters, namely fuel price, electrical power sales price and DE system capital cost. In all cases, the designs and operating schedules developed are aligned with expectations and reported experience. The interaction between the thermal storage unit and fuel price has provided further evidence of the effectiveness of the design methodology. The ability of the tool to design while imposing user-defined constraints on CO_2 emissions has been demonstrated. Because of the lack of large-scale low- or zero-carbon DE systems in the library of options, together with the relatively high per-unit cost of solar thermal technologies, only conventional, fuel-fired, technologies have been selected.

5.2. Second stage: existing DE solution

In this second stage, the performance of the software tool will be evaluated through its application to the design and operation of an existing DE solution. Calculations will be carried out firstly to: i) simulate the plant, allowing validation of the simulation models; ii) establish the accuracy of the time band approach adopted in the methodology; and iii), assess the design and optimisation capabilities of the tool.

An operational site of EDF is considered for all these studies. The plant serves 700 residents and some local communal buildings with heat in the form of hot water. Electricity is sold to the national grid. The actual power demand of the site was not disclosed due to the non-disclosure agreement with the customers. The main components of the plant are shown in Table 12.

Table 12 Components of EDF's operational site

DE system	Characteristics	
Natural Gas Engine	Capacity, MWe	1.358
	Electrical efficiency, %	34
	Heat/electricity ratio	1.23
Natural Gas Boilers (x 4)	Capacity, MWth	1.40
	Efficiency, %	93
Thermal Storage Units (x2)	Capacity, MWhth	4.5
	Volume, m^3	105
DHN	Supply temperature, °C	90
	Return temperature, °C	70

The available data are:

- Totals of fuel consumption, heat and power generation in every month of a year.
- Heat output of two average days (week day and weekend day) per season, in an hourly format
- Detail of heat output from CHP and boilers for two average days (week day and weekend day) in an hourly format, but only for Winter and Spring seasons.
- CHP model and efficiency of boilers.

Seasons were defined as Winter (January, February and March); Spring (April, May and June); Summer (July, August, and September); and Autumn (October, November, December).

It is assumed that heat generation meets the heat demand of the site plus network losses. The corresponding generated power is sold to the grid at a variable tariff. EDF supplied relative power sales tariffs in the form of percentages with respect to the peak price. These tariffs vary with time, type of day, and season, (e.g.: 100% at 5:00 pm during January). Actual commercial data, however, are not available (neither for fuel price nor for power tariffs) for reasons of commercial confidentiality.

5.2.1. Validation: simulation of the existing DE solution

The performance of the plant was simulated using the existing operational schedule in order to validate the DE solution model. Figure 10 is a schematic representation of the simulation approach adopted. The outputs of the plant (fuel consumption, power and heat production) are calculated using the equipment part loads in each time scenario. Sixteen time scenarios were considered, four for each kind of day and season. It was assumed that both seasons comprise 66 week days and 24 weekend days.

The validation was done only for Winter and Spring due to the availability of hourly partial loads for the engine and boilers. The simulation results are shown in Table 13.

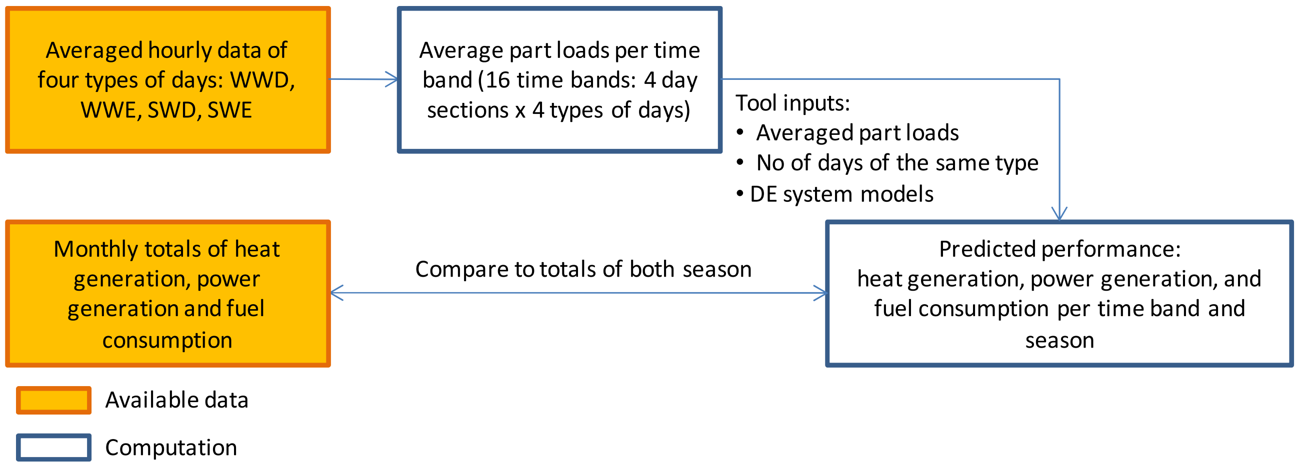

Figure 10 Diagram of simulation approach and available data using 4 time bands per type of day

Table 13 Simulation results using the time bands specified in the project

	Real	Simulation	Error (%)
Fuel consumption, MWh	8,583	9,003	4.89
Power production, MWh	2,576	2,583	0.27
Heat production, MWh	4,566	4,514	-1.14
Heat from engine, MWh	3,284	3,196	-2.68
Heat from boilers, MWh	1,282	1,318	2.81
CHP heat/power ratio	1.27	1.24	

From Table 13 it can be seen there is a good agreement between the actual fuel consumption, power and heat production, and the simulation outputs. These results were obtained allowing very low part-loads in the engine in order to simulate the fact that it works only a fraction of a time band. In practice, the engine is either operational or not (on/off). Note that averaged hourly data showed working times of less than 10 min.

The small discrepancies are thought to be related to: i) differences between the equipment model and actual performance, e.g. reported heat to power ratio of 1.27 vs. 1.24 in the model, and ii) differences in the number of days assumed per season vs. the actual ones. Nevertheless, the results demonstrate the validity of the DE solution model to reproduce the outputs or performance of a DE centre from the part-loads of different DE systems in a reduced number of time scenarios.

5.2.2. Investigation of data granularity

The EDF data provides the opportunity to explore in more detail the effect of using a relatively small number of time bands (24) to represent the yearly demand and therefore, the operation of a DE centre. Three studies were carried out with this objective:

1. Comparison of **simulation** results based on a typical day with 24 time blocks (24 hourly part-loads), versus the results based on a smaller number of part-loads averaged for specific time blocks in a day.

2. Comparison of **operational optimisation** results based on a typical day with **24 time blocks**, versus the results obtained with a **smaller number of time blocks in a day.** Heat output data (minus losses) are assumed equal to heat demand.
3. Comparison of **operational optimisation** results for **twelve months** versus the results obtained for **three seasons**. Heat output data (minus losses) are assumed equal to heat demand.

This investigation compares the outputs of the model when based on lumped data (e.g. only three seasons in a year) to results obtained using more granular data (e.g. monthly data).

5.2.2.1. Number of time bands in a day: Simulation

The hourly data (for one season at a time) were applied directly in the design tool. Tables 14 and 15 show the errors obtained for Winter and Spring simulations using hourly data (of an average day) versus using time bands. (Initially, four time bands per day are considered, selected according to heat profile.) As opposed to the whole year validation, where weekends were taken into consideration, a single type of day (week day) was assumed in this case, for simplicity.

Table 14 Winter simulation (hourly vs. 4 time bands)

		Hourly		**4 Time bands**	
	Real, MWh	Simulation, MWh	Error (%)	Simulation, MWh	Error (%)
Fuel consumption, MWh	5,338	5,768	8.06	5,768	8.06
Power production, MWh	1,594	1,646	3.26	1,646	3.26
Heat production, MWh	2,902	2,907	0.17	2,907	0.17
Heat from engine, MWh	2,036	2,036	0.00	2,036	0.00
Heat from boilers, MWh	866	871	0.58	871	0.58
CHP heat/power ratio	1.27	1.24		1.24	

Table 15 Spring simulation (hourly vs. 4 time bands)

	Real, MWh	**Hourly**		**4 Time bands**	
		Simulation, MWh	Error (%)	Simulation, MWh	Error (%)
Fuel consumption, MWh	3,245	3,388	4.41	3,388	4.41
Power production, MWh	982	1,012	3.05	1,012	3.05
Heat production, MWh	1,664	1,638	-1.56	1,638	-1.56
Heat from engine, MWh	1,248	1,252	0.32	1,252	0.32
Heat from boilers, MWh	416	386	-7.21	386	-7.21
CHP heat/power ratio	1.27	1.24		1.24	

The simulation results were found to be independent of the number of blocks considered, either 24 blocks of one hour, or four blocks of several hours as can be seen in Tables 14 and 15. Twelve, eight, six, and five time bands with different lengths were also investigated and the results were exactly the same. This can be explained by the fact that hourly part-loads, as inputs to the calculations, will give the same total results as averaged part-loads. Figure 11 illustrates the differences between an hourly and a 'time band' simulation approach.

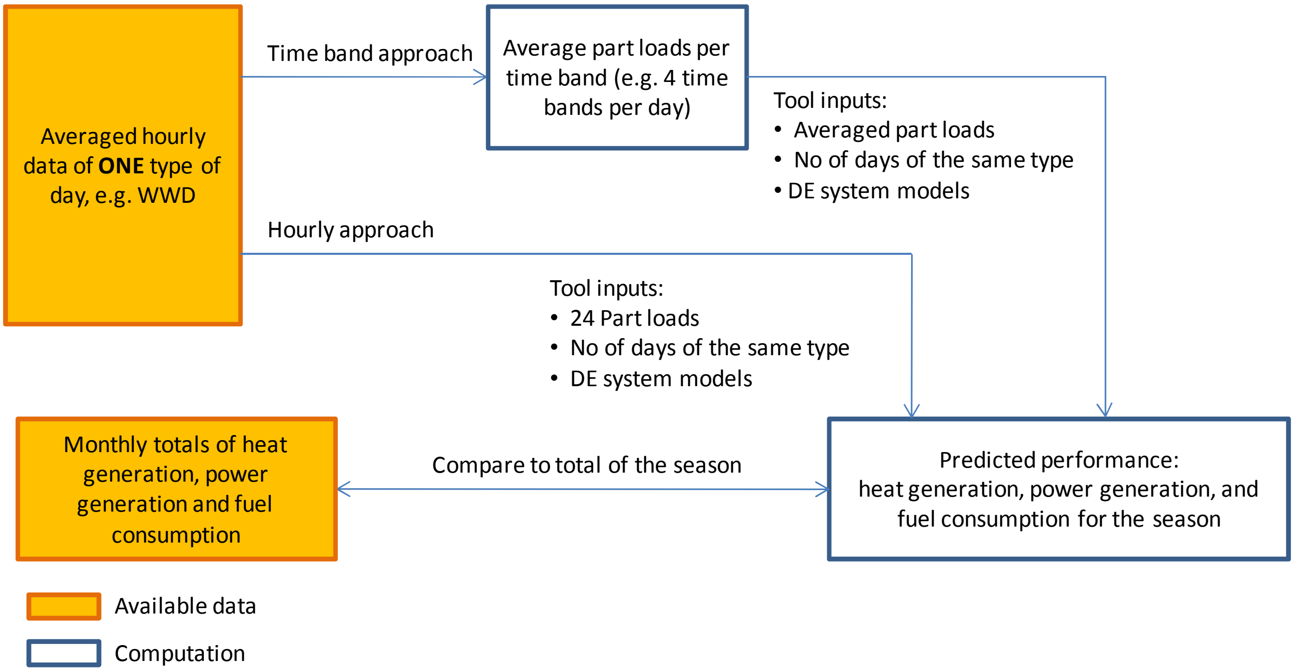

Figure 11 Simulation approach using 24 one-hour or more granular time bands

5.2.2.2. Number of time bands in a day: Operational optimisation

The previous section demonstrated that the simulation results are independent of the number of time bands and/or their definition. However, the DE designs generated and their corresponding operating schedule may differ significantly with the number of time bands and their lengths, as optimisation relies on the price of fuel and power sales tariffs (absolute value and variation through the day). An important consideration determining whether the CHP unit should run (for a given fuel price, and given CHP and boiler efficiencies) is the power sales tariff at which the boilers and CHP units produce heat at the same cost. At lower power sales tariffs, boilers will produce heat more cheaply than the CHP unit; in this case, the CHP unit should not run except to satisfy the power demand of the site. Equation (6) allows the minimum power sale tariff to be calculated, given the fuel price, efficiencies, heat-to-power ratio of the CHP unit and variable maintenance costs:

$$SalesTariff_{\min} = FP\left(\frac{1}{\eta_{CHP_e}} - \frac{ratio_{CHP}}{\eta_B}\right) + MC_{CHP} - (ratio_{CHP})MC_B \qquad (6)$$

where:

FP = fuel price

MC_{CHP} = variable maintenance cost of the CHP unit

MC_B = variable maintenance cost of the boilers

Ratio = ratio of thermal output to power output of the CHP unit

η_{CHPe}= electrical efficiency of the CHP unit

η_B = efficiency of the boiler

Average power sales tariffs may be significantly different from the actual values and may fall below or above the minimum power sales tariff of the system. Later paragraphs will refer to the minimum tariff as the ‘threshold tariff’ and its relation to fuel price will be referred to as the ‘threshold ratio’.

For reasons of commercial confidentiality, actual commercial data are not available (neither fuel price nor power tariffs) to test the capabilities of the methodology to optimise the actual operating schedule of the existing plant. Here operational optimisation is carried out assuming a ‘peak power sales tariff to fuel price’ ratio of 3.5. The relative power sales tariffs in the form of percentages with respect to the peak price supplied by EDF and presented in Figure 12 are applied in this study.

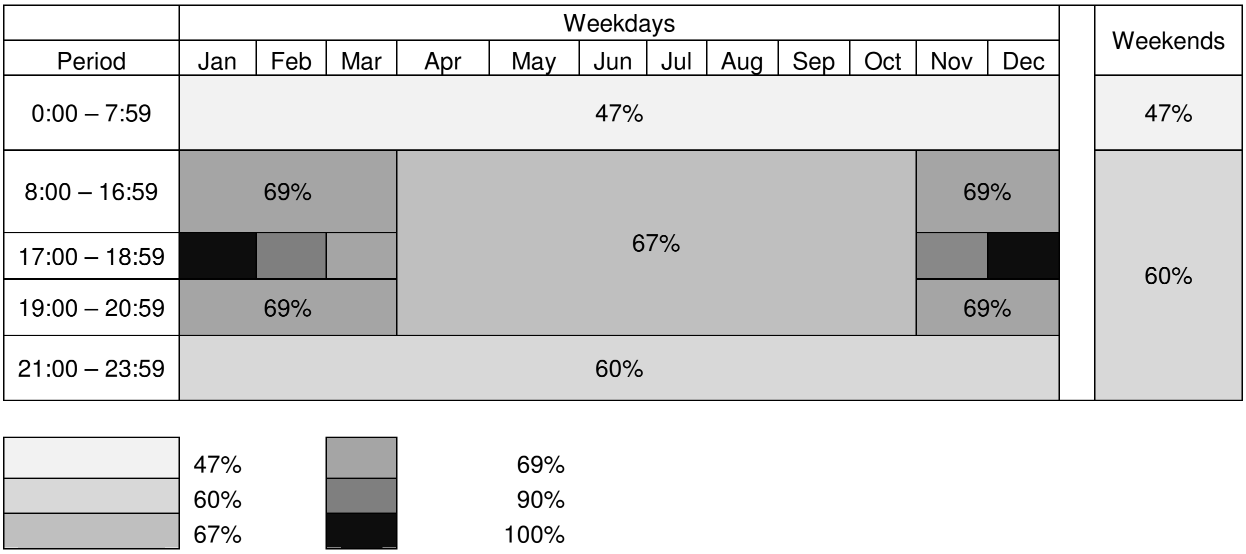

Figure 12 Tariff structure of the existing plant

For this study, heat production is constrained to be equal to the actual demand. The operating loads (on/off/percentage part-load) of the engine and boilers are selected by the optimisation solver to minimise total operating costs (fuel costs less electricity export revenue). The results are discussed based on the differences between the hourly demand data and the same data averaged in time bands.

For simplification, a single type of day (week day) was assumed. Winter and Spring were studied separately with 24 (hourly), 12, 8 and 4 time bands evenly distributed from midnight (0:00). Two other time band definitions were studied: 4 time bands distributed according to heat profile, and 5 time bands defined according to power sales tariff variations depicted in Figure 12.

Tables 16 and 17 show the results obtained for a ‘peak power sales tariff to fuel price’ ratio of 3.5 with and without thermal storage for the Winter season.

The threshold ratio of the existing DE solution for a fuel price of 0.111 £/Nm^3 is 2.26. This means the CHP unit will be switched off in those time bands where the power tariff is below 65% of the peak, i.e. 3.5 x 0.65 = 2.26. In Winter and Spring the existing plant receives a power sales tariff above the threshold during week day time and below it at nights and weekends. The switch happens instantly at 08:00 and 20:59 (see Figure 12). The way in which the hours are gathered into time bands may lead to average tariffs above the threshold; the tool will then predict that the CHP unit should run for more hours than would be predicted using a more granular approach and the converse also applies.

Table 16 Operating optimisation results with respect to the number of time bands and their definition in Winter without thermal storage.

	Fuel consumption, MWh	Power production, MWh	Heat production, MWh	Operating expenses, £	Revenues, £	Total costs, £
24 time bands (hourly)	5,347	1,387	2,902	73,337	-39,985	33,352
12 time bands	5,528	1,500	2,902	76,199	-42,631	33,568
Difference with respect to 24h, %	3.39	8.15	-	3.90	6.62	0.65
8 time bands	5,151	1,266	2,902	70,243	-36,538	33,706
Difference with respect to 24h, %	-3.67	-8.72	-	-4.22	-8.62	1.06
4 time bands	5,162	1,273	2,902	70,417	-35,396	35,021
Difference with respect to 24h, %	-3.46	-8.22	-	-3.98	-11.48	5.00
5 time bands (acc. to power tariffs)	5,346	1,387	2,902	73,324	-39,985	33,339
Difference with respect to 24h, %	-0.02	0.00	-	-0.02	0.00	-0.04
4 time bands (acc. to heat profile)	5,033	1,193	2,902	68,373	-34,154	34,219
Difference with respect to 24h, %	-5.87	-13.99	-	-6.77	-14.58	2.60

Table 17 Operating optimisation results with respect to the number of time bands and their definition in Winter with thermal storage.

	Fuel consumption, MWh	Power production, MWh	Heat production, MWh	Operating expenses, £	Revenues, £	Total costs, £
24 time bands (hourly)	5,774	1,642	2,911	80,019	-47,057	32,962
12 time bands	5,970	1,768	2,911	83,145	-50,101	33,044
Difference with respect to 24h, %	3.39	7.67	-	3.91	6.47	0.25
8 time bands	5,563	1,516	2,911	76,716	-43,571	33,145
Difference with respect to 24h, %	-3.65	-7.67	-	-4.13	-7.41	0.56
4 time bands	5,563	1,516	2,911	76,708	-42,207	34,501
Difference with respect to 24h, %	-3.65	-7.67	-	-4.14	-10.31	4.67
5 time bands (acc. to power tariffs)	5,776	1,642	2,911	79,925	-47,057	32,862
Difference with respect to 24h, %	0.03	0.00	-	-0.12	0.00	-0.30
4 time bands (acc. to heat profile)	5,359	1,389	2,911	73,492	-39,631	33,861
Difference with respect to 24h, %	-7.19	-15.41	-	-8.16	-15.78	2.73

Table 18 represents the operating schedule obtained for different time bands during a day. This table clearly shows how twelve time bands, for instance, lead to the CHP working for an additional hour because the average tariff for the 20:00 to 21:59 block falls above the threshold. Four time bands distributed according to the heat profile lead to even worse results since the average tariff of the 06:00 to 10:59 block falls below the threshold. The best results are obtained with five time blocks selected according to the power sales tariffs because the limits of profitable vs non profitable hours are respected in this case.

Table 18 Operating schedules for different number of time bands in a day – Winter week day (No thermal storage).

Hour	hourly	12 time bands	8 time bands	4 time bands (distributed from 0 h)	4 time bands (acc. to heat profile)	5 time bands (acc. to power tariffs)
0 - 6						
7						
8	√	√				√
9	√	√	√			√
10	√	√	√			√
11	√	√	√		√	√
12	√	√	√	√	√	√
13	√	√	√	√	√	√
14	√	√	√	√	√	√
15	√	√	√	√	√	√
16	√	√	√	√	√	√
17	√	√	√	√	√	√
18	√	√	√	√	√	√
19	√	√	√	√	√	√
20	√	√	√	√	√	√
21		√		√	√	
22				√		
23				√		

When thermal storage is used, the same trend is observed. Note that heat production with thermal storage increases slightly due to the heat losses from the tank (assumed to be 2% daily).

Tables 19 and 20 show the results obtained for week days in Spring with the same peak power sales tariff to fuel price ratio.

As may be seen in Table 19, optimisations in Spring are subject to higher errors than in Winter when the thermal storage is not being used. Further verification revealed that this result is related to the minimum operating load of the engine (0.84 MWhth). Since the hourly demand figures decrease in Spring, banding may lead to demand averages which are above or below the minimum operating point. As consequence, the resulting operating schedules may indicate more or fewer CHP running hours than expected in reality, giving rise to inaccurate prediction of power generated and fuel consumption.

Table 19 Operating optimisation results with respect to the number of time bands and their definition in Spring without thermal storage.

	Fuel consumption, MWh	Power production, MWh	Heat production, MWh	Operating expenses, £	Revenues, £	Total costs, £
24 time bands (hourly)	2,209	265	1,664	28,525	-7,090	21,436
12 time bands	2,194	255	1,664	28,289	-6,841	21,448
Difference with respect to 24h, %	-0.68	-3.77	-	-0.83	-3.51	0.06
8 time bands	2,097	195	1,664	26,756	-5,228	21,528
Difference with respect to 24h, %	-5.07	-26.42	-	-6.20	-26.26	0.43
4 time bands	1,783	0	1,664	21,788	0	21,788
Difference with respect to 24h, %	-19.28	-100.00	-	-23.62	-100.0	1.64
5 time bands (acc. to power tariffs)	1,998	133	1,664	25,182	-3,572	21,611
Difference with respect to 24h, %	-9.55	-49.81	-	-11.72	-49.62	0.82
4 time bands (acc. to heat profile)	2,385	374	1,664	31,306	-9,841	21,464
Difference with respect to 24h, %	7.97	41.13	-	9.75	38.42	0.13

Table 20 Operating optimisation results with respect to the number of time bands and their definition in Spring with thermal storage.

	Fuel consumption, MWh	Power production, MWh	Heat production, MWh	Operating expenses, £	Revenues, £	Total costs, £
24 time bands (hourly)	3,612	1,128	1,673	50,636	-30,238	20,397
12 time bands	3,502	1,060	1,673	48,898	-28,404	20,488
Difference with respect to 24h, %	-3.05	-6.03	-	-3.43	-6.07	0.45
8 time bands	3,499	1,059	1,673	48,859	-28,369	20,490
Difference with respect to 24h, %	-3.13	-6.12	-	-3.51	-6.18	0.46
4 time bands	2,091	688	1,673	39,421	-18,437	20,984
Difference with respect to 24h, %	-42.11	-39.01	-	-22.15	-39.03	2.88
5 time bands (acc. to power tariffs)	3,614	1,130	1,673	50,760	-30,285	20,390
Difference with respect to 24h, %	0.06	0.18	-	0.24	0.16	-0.03
4 time bands (acc. to heat profile)	3,357	971	1,673	46,617	-25,835	20,783
Difference with respect to 24h, %	-7.06	-13.92	-	-7.94	-14.56	1.89

Table 21 illustrates how the minimum operating point together with the threshold price ratio affects the operating schedule. The tick represents actual CHP running hours and tariffs (corresponding to results in Table 19). The shading represents hours in which thermal demands are above the minimum operating point and where the engine would run if the tariffs were above the threshold (the shading corresponds to an example in which a flat tariff of 69% applies).

Table 21 Operating schedules for different number of time bands in a day – Spring week day (No thermal storage).

Hour	hourly	12 time bands	8 time bands	4 time bands (distributed from 0 h)	4 time bands (acc. to heat profile)	5 time bands (acc. to power tariffs)
0-5						
6						
7						
8	√	√				
9		√				
10						
11						
12						
13						
14						
15						
16					√	
17					√	√
18	√	√	√		√	√
19	√	√	√		√	√
20	√		√		√	√
21					√	
22						
23						

Shading indicates operational hours of CHP unit when a flat tariff of 69% of the maximum is applied.

Table 21 clearly shows how the results are very sensitive to the banding structure adopted when the thermal demand is very close to the minimum operating point of the engine. Even when the bands are selected according to the heat profile, there may be significant error unless a very specific case-dependent banding system is adopted where the minimum operating point of the engine is considered during Transition periods. This is not practical since, in design, the size of the engine is not known beforehand.

Nevertheless, when thermal storage is used (Table 20) the optimisation with hourly time bands and the optimisation with five bands defined according to power sales tariffs are the most similar, as in the Winter case (Table 18). The differences in fuel consumption and power output reported in Tables 19 and 20 are less than 1%. This good agreement is due to the fact that the thermal storage allows the CHP unit to run at times that the thermal demand is lower than its minimum operating point and therefore, the influence of the threshold demand is eliminated. Under these circumstances, the CHP unit will be switched on and off based only on the power sales tariff. (Note that operating schedules with thermal storage in Spring are exactly the same as those in Winter (Table 18) – the CHP unit runs during profitable periods, between 08:00 to 20:59)

Since in this particular case study, the electrical demand is unknown, there is no other incentive to use the CHP unit but for power sales. It may be concluded that power sales tariffs are so significant that they should dictate the selection of the time bands.

5.2.2.3. Number of time bands in a year: Design and optimisation

The software tool being developed in this project uses relatively few time bands to represent temporal variation in demand and tariffs and to determine the operating schedule. As shown in Section 5.2.2.1, the averaged data for this level of granularity do not adversely affect simulation results; but as shown in Section 5.2.2.2, the operational optimisation of the DE solution is sensitive to the temporal variation in power sales tariffs. In this section, the impact of lumping months into seasons on both operational optimisation and design (structural optimisation) will be investigated.

Lumping months into seasons is expected to affect operational optimisation and design of a DE centre, especially for Transition seasons (Spring and Autumn) where thermal demand changes significantly during the season. Hourly thermal demand data were available for an average week day and an average weekend day of each of the four seasons, and monthly (total) heat and power generation data were available. In order to perform the study, the seasonal daily profile data were scaled to obtain a characteristic daily profile for each month; this scaling corresponded to the total thermal demand per month. Five bands per week day and three bands per weekend day were selected, following the results reported in Section 5.2.2.2.

The developed methodology was used to optimise the operating schedule of each month separately and then the results were added up to compute the performance of a year (12 months x 8 blocks = 96 time bands). These monthly results were taken as the basis to compare the results of optimised operating schedules obtained with three seasons of 8 daily blocks each (24 time bands). Two different definitions of seasons were studied; first where Winter started in January (as in the original data), and then defining Winter as November to March; Transition as April, May, September and October; and Summer as June through August. This second definition of seasons respects the tariff structure defined for the existing solution (Figure 12), but it also takes into consideration the thermal demand profile.

The purpose of the design methodology is to select which DE systems will exist in the energy centre; however, the software tool in its current form can only consider a limited number of time bands. Therefore, it cannot be applied directly for design for the more granular cases being considered. In order to study the implications for design, optimisation results were generated for 12 months and then for two different definitions of the three seasons and compared. The optimisation results indicate which design would be selected by the tool if it were applied in design mode.

Three engine sizes are considered:

a) 1.35 MWe engine
b) 1.12 MWe engine
c) 0.85 MWe engine

Each case includes four auxiliary boilers of 1.4 MWth and two heat accumulators of 4.9 MWh total thermal capacity. Two ‘peak power sales tariff to fuel price’ ratios were evaluated: 3.5 and 6.2, to explore the impact of granularity on design under different scenarios. Table 22 presents the threshold ratios for each configuration and relates these to the ‘peak power sales tariff to fuel price’ ratio.

Table 22 Threshold ratios for each equipment configuration (fuel price: 0.111 £/Nm^3)

Engine size	Threshold ratio	Threshold ratio relative to 'peak power sales tariff to fuel price' ratio	
		3.5	**6.2**
1.35 MWe	2.26	65%	36%
1.12 MWe	2.30	66%	37%
0.85 MWe	2.38	68%	38%

Operational optimisation

Operational optimisation results are shown in Appendix G. Tables G.1, G.2, G.5 and G.6 contain results obtained for the original definition of seasons, while Tables G.3, G.4, G.7 and G.8 contain the results obtained for seasons defined according to power sales tariff structure. Each equipment configuration leads to very specific conclusions, as discussed below.

Table 23 represents the operating schedules obtained for the 1.35 MWe engine with various definitions of seasons. The actual tariff structure showed no months with ratios below the threshold in the profitable block (08:00 to 20:59 weekdays). Thus, the threshold price ratio for power production does not dictate how seasons should be defined in this case.

However, the minimum operating point of the engine (0.84 MWhth) prevents its operation from May to September, which can create problems when lumping months into seasons. As can be seen in Table 23, the original definition of seasons results in average demands above the minimum for May and June. The consequence is an overestimation of power production as shown in Table G.1. The new definition of seasons overestimates the power production in four time bands but underestimates it in two; consequently power production is underestimated overall, as shown in Table G.3.

The tables in Appendix G show that the difference in fuel consumption and power production with respect to the monthly approach is typically under 5 and 10%, respectively, using the original definition of seasons. However, some large and very large errors arise (e.g. 15% and 77%). When seasons are redefined, based on power sales tariffs, the difference in fuel consumption and power production, compared to the monthly approach, is consistently reduced, to less than 3% and 10%, respectively. This improvement stems from the fact that the new definition, although it underestimates power production, is based on more symmetrical distribution of heat demand. Correspondingly, the total annualised costs (capital costs included) and CO_2 emissions are also closer to the monthly results.

The use of thermal storage reduces or eliminates the impact of the threshold demand as explained in the previous section. The CHP unit will be switched on in all the shaded time periods shown in Table 23 since in these periods the 'power to fuel price ratios' ratios are above 2.26. Therefore, the difference, in fuel consumption and power production, for either seasonal approach with respect to the monthly approach, is reduced (Tables G.2 and G.4). In this respect it can be concluded that banding according to thermal demand profile could lead to better results in the case of no use of thermal storage; where there *is* thermal storage, defining bands in terms of thermal demand makes little difference.

Table 23 Operating schedules for different number of time bands in a year – **CHP 1.35 MWe** (No thermal storage).

	Time slots	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Monthly	0-8 h WD												
	9-16 h WD	√	√	√	√	√						√	√
	17-18 h WD	√	√	√	√	√						√	√
	19-20 h WD	√	√	√	√	√						√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												
Original seasons (Winter starts in Jan)	0-8 h WD												
	9-16 h WD	√	√	√	√	√	√	√				√	√
	17-18 h WD	√	√	√	√	√	√	√				√	√
	19-20 h WD	√	√	√	√	√	√	√				√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												
New Seasons (Winter: Nov – Mar; Summer: Jun – Aug)	0-8 h WD												
	9-16 h WD	√	√	√	√								√
	17-18 h WD	√	√	√	√	√	√				√	√	√
	19-20 h WD	√	√	√	√	√	√				√	√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												

Shading indicates that CHP unit will run in these periods as well if thermal storage is used.

Table 24 represents the operating schedules obtained for the 1.12 MWe engine with various definitions of seasons. The threshold ratio is 2.30. The actual tariff structure showed no months with ratios below 2.30 in the profitable block (08:00 to 20:59 week days). Thus, the threshold ratio for power production does not determine which definition of seasons is more appropriate. Nor does the minimum operating point of the engine (0.54 MWth) because the thermal demands are higher than its minimum in every month.

As expected, with the smaller (1.12 MWe) engine, the differences in fuel consumption and power production with respect to the monthly approach are small (less than 5%) for either definition of seasons (Table G.1 and G.3). The new definition of the seasons improves the results, because the thermal demands are more similar within each season than in the original definition of seasons.

Table 24 Operating schedules for different numbers of time bands in a year – **CHP 1.12 MWe** (No thermal storage).

	Time slots	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Monthly	0-8 h WD												
	9-16 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	17-18 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	19-20 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												
Original seasons (Winter starts in Jan)	0-8 h WD												
	9-16 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	17-18 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	19-20 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												
New Seasons (Winter: Nov – Mar; Summer: Jun – Aug)	0-8 h WD												
	9-16 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	17-18 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	19-20 h WD	√	√	√	√	√	√	√	√	√	√	√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												

Table 25 represents the operating schedules obtained for the smallest (0.85 MWe) engine with different definitions of seasons. The threshold ratio is 2.38. The actual tariff structure showed seven months (April to September) with ratios below 2.38 in the profitable block (08:00 to 20:59 weekdays). In this case, it is important for the definition of seasons to distinguish between those months above and those below the threshold. As in the previous case the thermal demands are higher than the minimum operating point of the engine in every time band.

As may be seen in Table 25, for the original definition of seasons, the CHP unit is switched on in April, May, June and October (all within the Transition season) because the average power sales tariff falls above the threshold. That is, months with high tariffs, e.g. November and December, are lumped together with a month with a low tariff. The consequence is an overestimation of power production, as shown in Table G.1.

When the seasons are defined according to the power sales tariff structure, months with tariffs above and below the threshold are not lumped together, the optimisation results are much closer to those obtained with a monthly approach, as shown in Table G.3. For example, the Transition season in the new definition includes no months above the threshold, while also lumping months with similar thermal demand (April, May, September and October).

Table 25 Operating schedules for different number of time bands in a year – **CHP 0.85 MWe** (No thermal storage).

	Time slots	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Monthly	0-8 h WD												
	9-16 h WD	√	√	√	√								√
	17-18 h WD	√	√	√	√								√
	19-20 h WD	√	√	√	√								√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												
Original seasons (Winter starts in Jan)	0-8 h WD												
	9-16 h WD	√	√	√	√	√	√	√				√	√
	17-18 h WD	√	√	√	√	√	√	√				√	√
	19-20 h WD	√	√	√	√	√	√	√				√	√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												
New Seasons (Winter: Nov – Mar; Summer: Jun – Aug)	0-8 h WD												
	9-16 h WD	√	√	√	√								√
	17-18 h WD	√	√	√	√								√
	19-20 h WD	√	√	√	√								√
	20-23 h WD												
	0-8 h WE												
	9-16 h WE												
	17-23 h WE												

Note that for small engines (e.g. 0.85 MWe) thermal storage does not improve the agreement between the monthly approach and the seasonal approach because the cogeneration capacity is always lower than the thermal demand, as explained in Section 5.1.2.4. The results are, however, sensitive to the definition of seasons. Typically, small engines will have higher 'minimum power sales tariffs' or 'threshold tariffs' due to lower efficiencies and proportionally higher variable maintenance costs. In this sense, whenever the equipment configuration results in a threshold price ratio near the actual tariff, careful evaluation of the sensitivity of the results with respect to the time band definition is needed.

These results illustrate how a 'smart' definition of the seasons, which lumps months with similar tariff structures and thermal demands, can reduce the errors between the seasonal approach and the monthly approach. This is especially seen in the cases without thermal storage. In this case, the errors are less than 4% of the total annualised costs and less than 8% of the total CO_2 emissions (Tables G.3, G.4, G.7 and G.8).

Design considerations

The operational optimisation results for different equipment selections shed light on how lumping of months into seasons affects the design results. For each scenario considered, the DE solutions can be ranked in terms of total annualised costs. The shading in Tables G.1 through G.8 highlight the best designs for each scenario. It is clear that the new definition of seasons gives better agreement with results using the monthly approach than does the original definition of seasons. Table 26 summarises these results.

Table 26 Summary of best design results (from Tables G.1 to G.8)

Peak power sales tariff to fuel price ratio	3.5		6.2	
Thermal storage?	No	Yes	No	Yes
Monthly	No engine	No engine	No engine	1.12 MWe engine
Original seasons	No engine	No engine	1.12 MWe engine	1.12 MWe engine
New seasons	No engine	No engine	No engine	1.12 MWe engine

As shown in Table 26, for the lower 'peak power sales tariff to fuel price ratio' (3.5), the same solution is ranked first in all cases (Tables G.1 – G.4, i.e. using monthly data or seasonal data, and with or without thermal storage). In all cases, the most cost-effective solution is to use boilers only and no cogeneration.

When the income from power increases, relative to the cost of fuel, the monthly approach again finds boilers to be the best solution unless thermal storage is used, when the 1.12 MWe engine is selected. With the original definition of seasons, however, the best design found uses a 1.12 MWe engine whether or not thermal storage is used, mainly because the income from power production is overestimated. (Note that the two best designs were within 1% of each other, when using this definition of seasons.) The results using the new definition of seasons are in good agreement with those of the monthly approach in all cases.

It may be concluded that appropriate designs may be obtained using a sensible definition of seasons and that there is no need for a more granular approach.

5.2.2.4. Summary of data granularity investigation

The sensitivity of simulation and operational optimisation results with respect to the number of time bands supports the simplified approach adopted in this work i.e. the use of relatively few time bands. It was demonstrated that as long as the time bands in a day are defined according to sensible parameters, e.g. power sales tariff, there is no need to accommodate more granular demand data. The error associated with using daily averages is less than 1% of the total costs.

Grouping months into seasons does not introduce a significant error in economic terms (less than 4%) or CO_2 emissions (less than 8%) either. The differences between a monthly approach and seasonal approach can be reduced by wise selection of seasons according to the yearly heat profile and tariff structure. The use of thermal storage, which is the base case for the Macro DE project, significantly reduces the influence of less granular data.

In further sensitivity analyses of the Case Study, five time bands for week days and three time bands for weekend days (based on power sales tariff variations) are used. Since no operational data are available for Summer and Autumn, electricity sales revenues cannot be calculated for those seasons as a point of comparison; therefore, the next section is based only on Winter and Spring, as in Section 5.2.1.

5.2.3. Validation: Operational optimisation

As mentioned earlier, actual commercial data are not available to test the capabilities of the methodology to optimise the actual operating schedule of the existing plant. Sensitivity of operational optimisation results with respect to the 'peak power sales tariff to fuel price' ratio is therefore discussed in this section. The relative power sales tariffs supplied by EDF, presented in Figure 12, that vary with time, type of day, and season, are applied.

An initial operational optimisation for both seasons was carried out with a 'peak power sales tariff to fuel price' ratio of 3.5. A thermal storage unit of the capacity of the existing unit, 4.9 MWh, was considered. It was assumed there is no net accumulation of heat in the storage unit over a 24 hour day. Figures 13 and 14 depict the optimised and actual operating schedules of the plant.

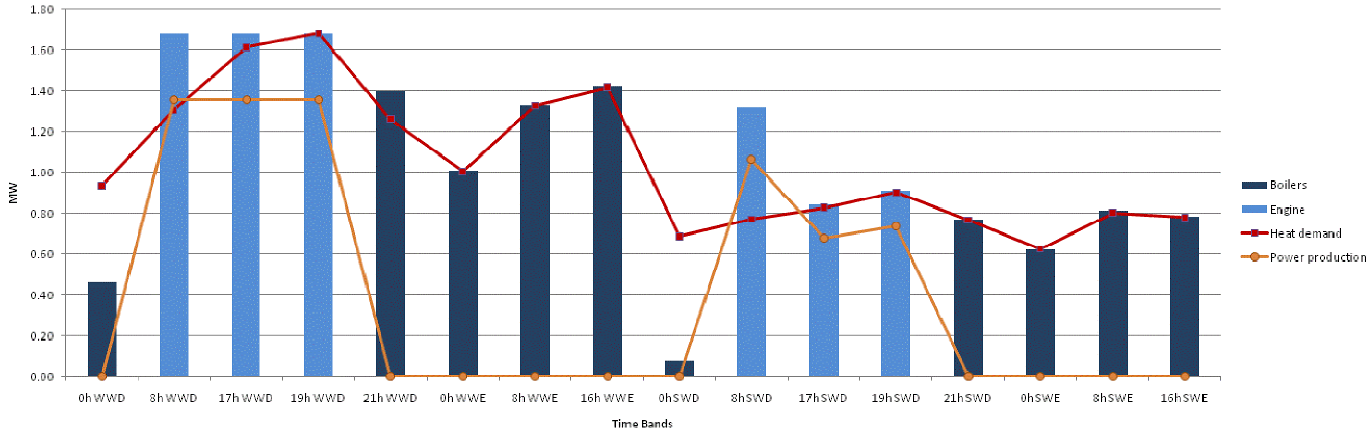

Figure 13 Optimised operating schedule of the plant for a 'peak power sales tariff to fuel price ratio' of 3.5. (Winter week days – WWD, weekends – WWE; Spring week days – SWD, weekends – SWE)

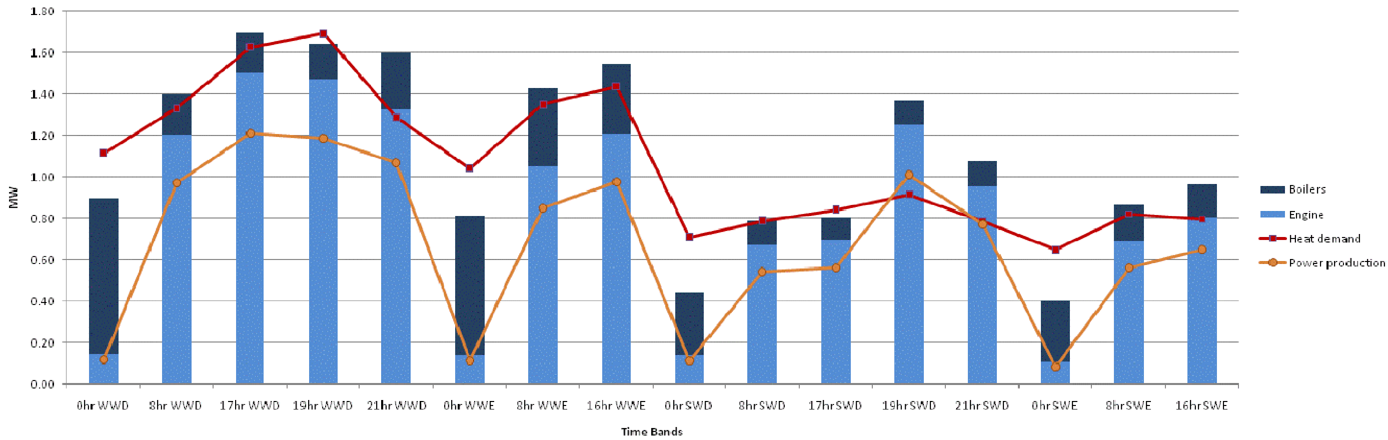

Figure 14 Actual operating schedule of the existing plant for time bands as in Figure 13.

Annual costs reduce from £57,000 to £55,000, a 5% improvement with respect to the simulated results. Revenues from electricity sales are reduced by £10,000, but operational expenses due to fuel consumption reduce by £12,000. However, these results depend strongly on the fuel price and power sales tariffs. For instance, a lower fuel price will reduce the threshold tariff of the system; in this case, the CHP unit may then run in time bands that were not profitable before. Likewise, with higher peak power tariffs, time bands increasingly lie above the threshold. Table 27 shows the sensitivity of annual heat production costs to the ratio of 'peak power sales tariff to fuel price'.

Table 27 Sensitivity with respect to the ratio of 'power sales tariff to fuel price'

Total annualised costs of heat production, £	Ratio of peak power sales tariff to fuel price**					
	5.0	4.0	3.5*	3.0	2.5	2.0
Simulation	26,327	42,533	57,792	73,144	100,153	136,166
Optimisation	21,405	39,150	55,007	67,326	82,699	102,459
Improvement over simulation results, %	18.70	7.95	4.82	7.95	17.43	24.75

* Ratio used in reference case: 4.02 p/kWh (peak power sale price) : 1.13 p/kWh (fuel price)

** Fuel price varied

In this case, improvements can be achieved for any 'peak power sales tariff to fuel price' ratio when the methodology is applied to optimise the operating schedule of the plant. From the actual operating schedule shown in Figure 14 one can conclude that the actual ratio is very likely to be around 4, which makes profitable the day time bands of the weekends (starting 08:00 and 16:00 WWE and SWE) while nights are unprofitable. An optimised operating schedule for this case, shown in Figure 15 and Table 28, will give an 8% improvement.

These results demonstrate the capabilities of the methodology to optimise an existing operating schedule, even with the use of relatively few data to represent heat demand.

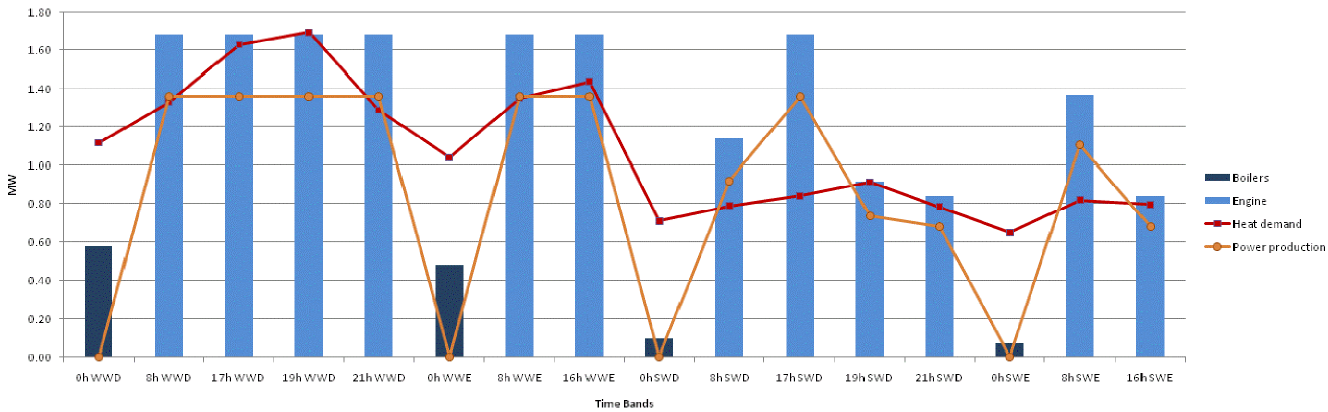

Figure 15 Optimised operating schedule of the plant for a 'peak power sales tariff to fuel price ratio' of 4.0

Table 28 Operational optimisation results for Winter-Spring and a price ratio of 4.0

	Real	Simulation	Optimisation (with existing thermal storage)
Fuel consumption, MWh	8,583	9,003	10,265
Power production, MWh	2,576	2,583	3,320
Heat production, MWh	4,566	4,514	4,566
Operational expenses, £	-	109,708	126,818
Revenue from power sales, £	-	- 67,175	-87,668
Total annualised cost of heat production, £	-	42,533	39,150

5.2.4. Validation: Design optimisation

The design capabilities of the tool were tested using EDF heat demand data and the same economic parameters used so far (Deliverable 1.1). The system is modelled with 16 time bands defined according to power sales tariffs as in Section 5.2.2 (5 time scenarios per week day, 3 time scenarios per weekend day and 2 seasons). Table 29 shows the library of DE system models considered.

Table 29 Library of equipment taken into consideration

Technology	Model	Capacity	Comment
Engines	4006-23TRS2	375 kWe	Unit from Deliverable 3.2 (WP3)
	XXXX5	500 kWe	Unit created
	G3512	1,120 kWe	Unit from Deliverable 3.2 (WP3)
	Deutz - TBG620V16K	1,350 kWe	Existing unit
	XXXX3	3,100 kWe	Unit created
Boilers	Rex 25	250 kWth	Unit from Deliverable 3.2 (WP3)
	XXX100	1,000 kWth	Unit created
	Hoval Limited - SR-plus 1400	1,400 kWth	Existing unit

As capital investment costs of the existing units are not available, these costs were estimated by scaling against known costs of other models collated in WP3. Note that only Winter and Spring are considered, since operational data are available only for part of the year. Since only two seasons can be considered, the capital cost is annualised by a factor which is half of the normal factor. This compensates for the fact that revenue from power sales is obtained for half of the year.

The results are summarised in Table 30. It was found that for a ‘peak power sales tariff to fuel price ratio’ of 3.5, it is not cost effective to include a CHP engine in the energy centre. This can also be seen in Table G.2 of Appendix G. It is only when the ratio increases to 6.2 that the tool selects a CHP engine to produce around 4,000 MWh of electrical power. This result indicates the annualised capital cost of the engine is not offset by power revenues unless the power sales tariff in peak times increases by 75%. Note that no power demand is included in the optimisation and therefore, there is no other incentive to use the CHP engine other than to sell electricity at a profitable tariff, as in the case of a conventional power plant.

When the power sales tariff is not favourable, three boilers of 1.0 MWth are selected to supply all the heat demand and to ensure back-up capacity (Peak demand is 2 MWth). The total thermal capacity is 3 MW, which is 42% of the installed capacity of the existing DE solution. When the power sales tariff is favourable, two boilers of 1.0 MWth and one engine of 1.12 MWe are selected. One boiler is used in Winter, as shown in Figure 16, and the other is for back-up. The total thermal installed capacity is in this case 43% of the existing capacity.

The optimal size of the thermal storage unit is 266 m^3. This unit can reduce the total annualised costs by less than 2%. The capacity of the tank is mainly exploited in Spring when heat demand decreases but power tariffs are still high, as shown in Figure 16. The small improvement in the economics of the plant with the thermal storage, however, makes its inclusion debatable.

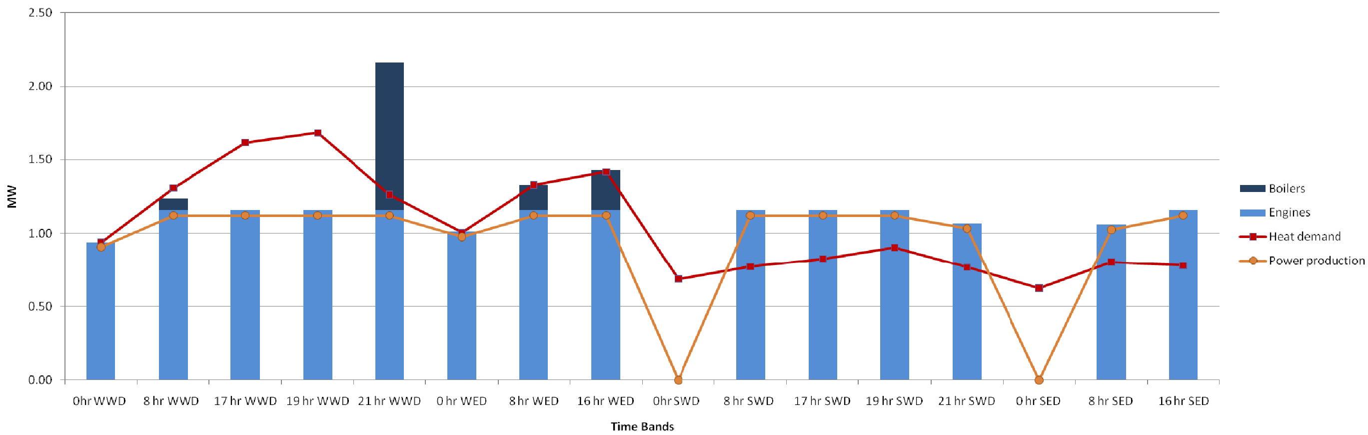

Figure 16 Operating schedule of DE solution for a 'peak power sales tariff to fuel price' ratio of 6.2 and thermal storage

Total CO_2 emissions (for the half-year) of each scenario are shown in Table 29. For electricity exported to the grid, a CO_2 emissions credit (0.485 g/kWh) is claimed to account for avoided emissions from central power plants. The DE solution for a 'peak power sales tariff to fuel price' ratio of 3.5 has the highest emissions because it does not export power to the grid. Both designs with a 'peak power sales tariff to fuel price' ratio of 6.2 have the lowest emissions because power is exported to the grid in the highest quantities.

A 'base case' is considered where the electrical demand of the site matches the actual power production of the plant and the heat demand corresponds to 85% of the actual heat production (10% distribution losses and 5% generation losses). The CO_2 emissions of this base case would be 2,215 tCO_2. The designs with the best environmental benefit are the ones with the highest power production at a profitable tariff of 6.2. The reduction of CO_2 emissions in these cases is 36%.

Table 30 Winter–Spring design results (5 time bands per week day and 3 in weekends according to power prices)

	Real	Simulation @ 3.5	Simulation @ 6.2	Design @ 3.5	Design @ 6.2	
					Without TS	With TS
Suite configuration	1.3 MWe engine	1.3 MWe engine			1.1 MWe engine	1.1 MWe engine
	1.4 MW boiler (x 4)	4 1.4 MW boilers		1.0 MW boiler (x 2)	1.0 MW boiler (x 2)	1.0 MW boiler (x 2)
	206 m^3 TS	206 m^3 TS				266 m^3 TS
Annualised capital investment, £	-	88,425	88,425	11,235	71,347	75,968
Operating costs, £	-	124,907	124,907	56,659	140,920	140,814
Revenue from power sold, £	-	- 67,175	-117,566	0	-170,583	-175,694
Total annualised heat production costs, £	-	146,157	95,766	67,894	41,684	41,089
Fuel consumption, MWh	8,583	9,003		4,938	11,617	11,611
Power production, MWh	2,576	2,583		0	4,062	4,047
Heat production, MWh	4,566	4,514		4,566	4,566	4,583
Heat from CHP, MWh	3,284	3,196		0	4,204	4,188
Heat from boilers, MWh	1,282	1,318		4,566	362	395
Local CO_2 emissions, t	1,708	1,792		983	2,312	2,311
Total CO_2 emissions*, t	1,533	1,613		2,057	1,416	1,422

*The ‘base case’ assumes an electrical demand of 2,573 MWh which gives an annual CO_2 production of 2,215 t including heat demand.

Even though actual economic details (cost of fuel and capital, power sales tariff, etc.) were not available for consideration in this study, it can be appreciated from these results that in either case the plant seems to be oversized. It is understood that there are historical reasons for this. Furthermore, if the real ‘peak power sales tariff to fuel price’ ratio is less than 6.2, the CHP plant, with its gas engine, would not be generating real economic benefit. If the real ‘peak power sales tariff to fuel price’ ratio is greater than 6.2, the purchase of two smaller boilers and a smaller CHP engine would have improved the economics of the project. Investing in oversized equipment can allow later expansion of the heating network; these opportunities have not been evaluated here, however.

5.2.5. Initial applications: Second stage – Summary

The new design methodology has been applied to an existing DE solution to validate the simulation models and to explore the operational and design capabilities of the tool for a range of scenarios. The proposed methodology proved to reproduce the operational results of the existing solution with a discrepancy of 5% or better.

Sensitivity studies demonstrate that the methodology is robust – that the simulation and operational optimisation results do not degenerate significantly when fewer time bands are used, which supports the simplified approach adopted in the methodology. The time bands, however, must be defined according to sensible parameters in order to produce the most accurate results, e.g. power sales tariffs with time of day and season; thermal profile in a year.

The optimised operating schedules developed for the existing DE solution are aligned with expectations and reported experience. For instance, low ‘peak power sales tariff to fuel price’ ratios reduce the amount of power being exported to the grid with the engine operating only in peak times. High ‘peak power sales tariff to fuel price’ ratios increase the amount of power exported to the grid with the engine operating normally at full capacity (when power sales tariffs are favourable).

The proposed methodology also allowed the design of improved DE solutions, compared to the existing one, by selecting different DE systems from a library of options. Again, the optimal solutions strongly depend on commercial parameters such as power sales and purchase tariffs and fuel prices (‘peak power sale to fuel price ratio’), and the purpose of the plant, e.g. whether electrical power is to be sold to the same customers as heat.

6. Conclusions

In conclusion, a methodology for the systematic design of optimised DE solutions or energy centres has been developed. The effectiveness of the methodology, and of the pre-prototype software tool in which it has been implemented, has been tested through application to a test case representing a characteristic zone and to an existing DE solution.

In the first case, the methodology clearly generated DE solutions that satisfy the heat demand, represented as average values for 24 time bands, as well as peak thermal demand, so as to minimise annual costs. Sensitivity studies demonstrated the design methodology responds appropriately to key parameters such as fuel price, electrical power sales price and DE system capital cost. In all cases, the designs and operating schedules developed are aligned with expectations and reported experience.

The application of the design methodology to an existing DE solution validated the DE solution model developed. The performance of the existing solution was reproduced with a discrepancy of 5%. It was also shown that the methodology allows the generation of improved operating schedules for an existing suite, and the design of optimal DE solutions by selecting different DE systems from a library of options given the economic parameters of the case.

Sensitivity studies, with the available existing data, demonstrated that operational and design optimisation results do not degenerate significantly when relatively few time bands are used. These results support the adoption of the simplified approach developed in the methodology (24 time scenarios instead of 8,760 hours in a year). The differences between a time band approach and an hourly approach can be reduced by wise selection of time blocks in a day, seasons in a year (e.g. according to the power sales tariffs), and the use of thermal storage. This conclusion is informing work in WP2 and in future stages of the Macro DE project.

Other aspects of the DE solution design tackled by the methodology are: sufficient back-up heat generation capacity in case of simultaneous failure of all CHP units; use of thermal storage to maximise revenue from power sales; ability to design solution while imposing constraints on CO_2 emissions; and the selection of different fuels with applicable availability constraints.

The methodology, and the pre-prototype software tool in which it has been implemented, can be used in future stages of the Macro DE project to allow quantitative assessment of the potential of DE for the UK with respect to its affordability, and its impact on CO_2 emissions and energy security.

7. Future work

7.1. DE solutions for 'characteristic zones'

In WP4.2, the software tool will be used to design and cost DE solutions for each of the characteristic zones defined in WP2. The overall performance of a DE solution will be evaluated in terms of its economic performance and CO_2 emissions. The baseline for performance analysis is that all electricity is centrally generated and that each gas user satisfies the average heat demand with a stand-alone boiler (80% efficient, 8 year life span), based on 2009 demand data. The performance of optimised DE solutions for each 'characteristic zone' will be compared to this baseline. In WP5 the results for each characteristic zone will be used to assess the UK potential for DE deployment.

It is intended that several near-best solutions are identified and ranked according to their performance to provide insights into the most attractive technologies and operating policies.

7.2. Sensitivity studies

The tool will be used to carry out sensitivity studies typically for a small number of characteristic zones in WP4.2. These analyses will address cost (e.g. cost of equipment, cost of fuels, to account for uncertainties in the data and future scenarios), demand (to account for uncertainties in the data and future scenarios, as well as considering size/scale of zones) and CO_2 impact (e.g. the cost of restricting CO_2 emissions to a given level will be assessed). Table 31 presents a provisional list of sensitivity studies – time and resource constraints of the project limit the scope of sensitivity studies.

Table 31 List of sensitivity studies on selected characteristic zones (provisional)

Parameter	Low	Base case	High
Demand	DECC scenarios for 2020	2009 levels (WP2 output)	DECC scenarios for 2020
Fuel cost		2009 levels (WP3 output)	+ *x*%
Electricity tariffs	Increase power import price by *x* p/kWh (peak and off-peak)	Assumptions	Increase power sales price by *x* p/kWh (both peak and off-peak)
Capital cost (DE solutions)	- *x*%	2009 levels (WP3 output)	*+ x%*
Infrastructure cost (DHN)	- *x*%	2009 levels (WP3 output)	+ *x*%
CO_2 emissions	20% reduction	2009 levels (WP 4 results)	30 % reduction
CO_2 emissions of central power plant	- *x*%	Assumptions	
Fuel diversity		Cost-optimal (WP4 results)	Reduce use of dominant fuel by *x*% Use *y*% biofuels
Zone size	Decrease size (no. users, total heat demand, area) by *x*%	Characteristic zone (WP2 results)	Increase size (no. users, total heat demand, area) by *x*%

These sensitivity analyses will interpret the results of the design methodology to explore the robustness of distributed energy solutions, that is, to provide understanding of how the predicted benefits of DE are affected by assumptions and key uncertainties in the input data and design methodology. The results of the sensitivity analyses will provide insights related to the costs of energy inputs, the capital investment required to install the DE solution, potential improvements to DE system performance, etc. The results will be analysed to relate outcomes to energy security, in terms of central vs local power generation and diversity of fuel types.

7.3. Assessment of technology improvements

Potential improvements in DE technology are a subject of investigation in Work Package 3 (Task 3.3). It is anticipated that technology improvements will lead to different unit capacities, lower capital costs, higher efficiencies, different heat-to-power ratios of combined heat and power units, etc. The design tool will be applied to assess the impact of these technology improvements with respect to cost, CO_2 emissions, fuel diversity and energy efficiency.

The design tool will be applied to selected characteristic zones to assess the impact on overall DE solution performance of specific improved technologies as summarised in Table 32.

Table 32 Analysis of technology improvements (for selected characteristic zones)

<table>
<tr><th>Technology improvement</th><th>Simulation and operational optimisation</th><th>Design</th></tr>
<tr><td>1</td><td rowspan="6">Substitute technology into three designs for characteristic zones using related (base case) equipment
What is the impact on cost and CO_2 emissions?</td><td rowspan="6">Design optimised DE solution for the same characteristic zones
Are ‘improved’ technologies selected?
What impact on cost, CO_2 emissions and fuel diversity?</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td></tr>
<tr><td>3</td></tr>
<tr><td>4</td></tr>
<tr><td>5 …</td></tr>
</table>

7.4. Assessment of potential of DE in the UK

The outputs of the design tool will allow analysis of the resulting DE designs with respect to affordability, reduction of CO_2 emissions, energy security and robustness of DE technologies. Sensitivity studies will explore whether macro-scale DE may be commercially viable in 2020. Comparison of results against the 2009 ‘baseline’ will demonstrate the potential impact on CO_2 abatement. Analysis of the types and quantities of fuels consumed will provide insights into energy security. Understanding the range of scenarios in which the DE solutions are energy-efficient and affordable will allow the robustness of these solutions to be evaluated.

7.5. Further development of the software tool

The software is being developed in the first instance to address the objectives of the ETI Macro DE project to assess the potential of DE in the UK. Within the ETI project, the software will be enhanced from a research tool to a more general (pre-prototype) tool for use beyond the project (Task 4.3). This software deliverable, together with appropriate documentation, will allow ETI to apply the software to a limited range of additional scenarios, e.g. other demand scenarios, alternative DE systems. The project timescales and resources limit the scope of software development. In WP5 (Task 5.3), a case for further development of the design software, subsequent to the project, will be prepared.

8. References

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Appendix A – Extract from Contract (Schedule 1 Part 3 – Research Services)

Work Package 4

Work Package 4 (WP4) will outline a methodology for the development of a software tool to identify optimal DE solutions to satisfy the aggregated electrical, heating and cooling demands for each characteristic zone. The cost of implementing and operating the DE solution and the resulting CO_2 emissions will be estimated for each characteristic zone.

In Task 4.1 the tool methodology will be formally constructed and implemented in a pre-prototype software tool. The tool will be evaluated using test data. In Task 4.2 the new pre-prototype tool will be applied to all the characteristic zones generated in Work Package 2. The tool will design optimised DE solutions for each characteristic zone and will evaluate the performance of these solutions with respect to cost, CO_2 emissions and energy efficiency based on the equipment characterisation in Work Package 3.

4.1 Tool development	
This task will develop a methodology to quantify the potential of Macro DE solutions in a zone using an aggregation approach, where electrical and thermal demand and available waste heat will be aggregated for each characteristic zone. This task will first develop the tool methodology, i.e. the series of calculations and selection steps to design DE solutions (the suite of DE systems and associated district heating network) and to evaluate the performance of these solutions with respect to cost and CO2 emissions per year. The methodology will comprise mathematical models of: the aggregated energy demand (temporal profiles); a range of DE systems for supplying heat, cooling and electricity; simulation and cost models for proposed DE solutions; optimisation-based design models for selecting and evaluating alternative DE systems. It will be assumed that electricity is imported from and exported to the grid. This tool methodology will then be implemented in a software environment. Through strong integration with activities in WP2 and WP3, suitable Excel file formats will be defined to represent supply and demand data for a characteristic zone. The design calculations (selection of supply equipment and operating modes, energy balances, district heating network design, cost calculations, etc.) will be implemented in MatLAB. Excel-MatLAB interfaces will link the inputs in Excel to the MatLAB programs and will export results back to the Excel. The methodology will be verified through an initial application of the pre-prototype tool to an existing DE solution, for which demand, supply and design data are available to the consortium. Consolidated data for aggregated demand and for the existing supply equipment will be presented in Excel files. Calculations will be carried out in MatLAB to simulate the plant, for validation purposes. The tool methodology will also be applied to optimally re-design the plant. These simulation and optimisation results will be analysed to establish whether the tool provides realistic performance and design information. The tool will be further verified through sensitivity studies, and the tool methodology will be improved to incorporate key learnings from the case study.	
Deliverables:	**D4.1:** Report detailing: • tool methodology and software architecture, including core algorithms, description of data structures for demand and waste heat data, mathematical models for supply system simulation and performance evaluation • tool effectiveness, including input and design results for test case, for a range of input assumptions and scenarios

	• Basic feasibility on tool effectiveness on other existing operational sites within the consortium where available • Acceptance criteria for training and acceptance of matlab code to be delivered in 4.3 approved in writing by the ETI.
Acceptance Criteria:	**The report including all the elements for Deliverable D4.1 as set out in the row above and that comprises:** • Clear description of the steps of the tool methodology such that it can be replicated by the ETI • Understand implications of the test case results with respect to relative accuracy and predictive capabilities

4.2 Evaluation of zones using the tool	
The tool developed in Task 4.1 will be applied to design DE solutions for all the characteristic zones generated in WP2. Once designs have been generated for each characteristic zone, the performance will be ascribed to all characteristic zones of each type of zone. These performance results will allow assessment of the overall impact on the UK of Macro DE solutions in WP5. The design results will be analysed and reviewed, both to verify the results and to check their sensitivity to assumptions. Sensitivity studies will test the robustness of the results and will provide additional insights related to the size and composition of the zones, the costs of energy inputs, the capital investment required to install the DE solution, potential improvements to DE system performance, etc.	
Deliverables:	**D4.2:** Report detailing: o DE solutions and performance predictions for each characteristic zone, including input data, sensitivity studies and analysis of impact of technology improvements. o Impact of proposed technology improvements on performance of overall DE solutions.
Acceptance Criteria:	**The report including all the elements for Deliverable D4.2 as set out in the row above and that comprises:** • **Analytical results of DE solutions and Zones with the CO_2 and cost aligned with objectives** • **High and Low sensitivities to three (Cost, CO_2, and Demand) scenarios that provide insight and confidence in the results**

4.3 Development of pre-prototype tool	
This task will take the tool methodology developed in Task 4.1 and add a preliminary interface for use at the ETI. The modifications will allow supply and demand inputs of a specific required format to be applied to the tool for evaluation	
Deliverables:	**D4.3:** • Basic adaptation of MatLAB tool to allow the ETI to incorporate current and future demand data with current technologies from 3.2 capable of the use identified in the row above.

Acceptance Criteria:	• Delivered .m code to the ETI which provides the use and tool set out above. • Training and other acceptance criteria agreed by the ETI for Deliverable D4.1. • “How to” document for use by the ETI clearly written in non technical terms and which is anticipated to be 1-3 pages.

Appendix B – Glossary and Definitions

Aggregation	The demand for heat or power of multiple users will be added together and dealt with as a single point of demand.
Characteristic zone	A typical set of users of heat and power (defined in WP2)
DE solution	The set of DE systems providing heat and generating power to satisfy the aggregated demand of a characteristic zone (or a specific energy zone)
DE system	A sub-system, component or packaged unit (e.g. engine, boiler, thermal storage unit) within the overall DE solution
Efficiency	The fraction of the energy content of a fuel converted to useable energy (electrical or thermal, or both) by a DE system or DE solution
Energy centre	The physical set of DE systems (and housing) comprising the DE solution
Local CO_2 emissions	Emissions generated through fuel combustion in the DE centre and equipment manufacture.
Heating network	The system delivering heat from the energy centre to users in a (characteristic) zone comprising pipes carrying hot water, heat exchangers for each heat user and metering and control systems.
Methodology	The set and sequence of calculations required to design optimised DE solutions given aggregated demand data and relevant DE system (supply equipment) models.
MM	millions
Operating mode	The status of a DE system that exists in the DE solution (i.e. on, off or at part-load).
Optimisation	The DE systems comprising the DE solution (and their operating modes for each season and time of day) will be selected to give the best performance with respect to a specified objective (e.g. cost of delivery).
Part-load	The percentage of heat output from the DE system with respect to its rated (maximum) heat capacity.
Site	An energy user within an energy zone (e.g. residential unit, commercial building).
Threshold	Tariff – power sales tariff at which boilers and CHP units produce heat at the same cost; Ratio – corresponding ratio of power sales tariff to fuel price
Time band (Time scenario)	Identified period of time in which heat and power demand vary around an average. Time bands can be defined for different sections of the day (i.e. morning, day, evening and night), type of

	day (e.g. week day and weekends), and season (e.g. Winter, 'Transition' or Summer)
Tool	The implementation of the design methodology in a software environment that allows the application of the methodology to particular data sets.
Total CO_2 emissions	'local CO_2 emissions' plus the credit or burden associated to power exported or imported from the grid.

Appendix C – Energy Input Data Format

Tables C.1 and C.2 illustrate the format of energy input data adopted for the pre-prototype software tool.

Table C.1 Example of format for aggregated heat demand of a characteristic zone

Thermal, MW	week days	hours	Winter	Summer	Transition
	0500 - 0900	5			
	1000 - 1600	7			
	1700 - 2100	5			
	2200 - 0400	7			
		Baseload			
		Peak			
		Days			
	weekend		Winter	Summer	Transition
	0600 - 1200	7			
	1300 - 1600	4			
	1700 - 2100	5			
	2200 - 0500	8			
		Baseload			
		Peak			
		Days			

Table C.2 Example of format for aggregated electricity demand of a characteristic zone

Electrical, MW	week days	hours	Winter	Summer	Transition
	0500 - 0900	5			
	1000 - 1600	7			
	1700 - 2100	5			
	2200 - 0400	7			
		baseload			
		peak			
		Days			
	weekend		Winter	Summer	Transition
	0600 - 1200	7			
	1300 - 1600	4			
	1700 - 2100	5			
	2200 - 0500	8			
		baseload			
		peak			
		Days			

Appendix D – Design Assumptions

The design principles and main assumptions adopted in the Macro DE design methodology are listed below. The basis for these can be found in Deliverable 1.1.

1. Heat and electrical power demand

Energy centres will be designed to allow maximum peak thermal load to be satisfied.

The performance of energy centres will be assessed for operation at loads averaged over each period of interest and assumed constant during these periods.

Existing DE infrastructure (energy centres and/or district heating networks) in the UK will not be taken into account.

2. District Heating Network (DHN)

All the heat produced by the energy centre will be delivered via the district heating network (DHN). The methodology will cost, but not design, the district heating network.

The effect of supply and return water temperature does not impact on the design of the energy centre. The temperature difference between supply and return is assumed to be 20 °C.

The cost model used for the district heating network will be developed in WP3 and documented in Deliverable 4.2. Operating costs, e.g. pumping costs, will be considered.

The cost of the district heating network is considered from the energy centre to the heat interface units (HIU) in dwellings.

Refurbishing of houses and buildings (heat exchangers replacement in dwelling) is out of the scope of design. The cost associated to this is not considering when costing the DHN.

Thermal losses of the district heating network account for 10% of the total heat demand of a 'characteristic zone' (MKN report, 2010; B. Courau interview, 2010). This value is a user input to the model

3. Revenues and expenditures

The cost of generating heat will be used to assess the DE solution performance (income from heat generation will not be included).

Net surplus and net deficit electricity per time band will be sold or bought, respectively, at the price applicable to the time band (initial cost data in Deliverable 1.1). Different tariff structures can be input; these must be aligned with the definition of time bands. The cost of connecting to the grid will not be accounted for.

Any capital items with a lifespan of less than the project life will need to be replaced; replacement costs will be incurred at the project outset.

Annualised capital investment will be given by linear depreciation of the capital over the life of the assets, where the life time is an input to the model:

- Equipment will be depreciated over 10 years
- The DHN will be depreciated over 25 years

The cost of housing the energy centre will account for 25% of the equipment Capex cost (Peters, M., Timmerhaus, K., West, R., 2003).

The basis for design cost calculations is 2009/2010. User inputs related to some other scenarios can be accommodated.

4. Supply technologies

The electrical grid provides resilience for meeting power demand. Therefore, no redundancy is provided in the energy centre for power production.

To specify back-up heating capacity in addition to CHP units, it is assumed that peak heat demand must be met by heating units alone. That is, the possibility of simultaneous failure of all CHP units sets back-up requirements (in line with guidance provided by consultants and energy centre operators).

The equipment models include the minimum part-load of equipment considered, in order to avoid mechanical damage or equipment malfunction, following supplier guidance. The values applied in this work are:

- Engines: 50%
- Turbines: 50%
- Fuel cells: 50 %
- Boilers: 5%

5. Thermal storage

Heat can be stored as hot water at the supply temperature (90℃) for short periods. Longer term storage solutions and other storage technologies are not considered – it is unclear that they are technology-ready and applicable to the UK, and their modelling significantly complicates the design methodology.

Ten percent (10%) of the total volume of the tank is treated as unavailable for heat supply at the required temperature.

The water supply and return temperatures, top and bottom of the thermal storage respectively, are assumed constant with time. Thermal losses are computed as 2% of total energy content (in line with guidance provided by consultants and energy centre operators). This value is a user input.

The heat capacity of the thermal storage is not relied upon to meet peak heat demand.

6. CO_2 emissions

CO_2 emissions generated through fuel combustion and equipment manufacture are accounted for, as documented in Deliverable 3.1.

CO_2 emissions associated with imported power are 0.485 g/kWh; equivalent credit is given for exported power on the grounds that exported power may offset centralised power production. Other values can be supplied as inputs.

Appendix E – Model for Design of DE Solutions

The entire model for design of DE solutions is described in the sections below.

Variables and Parameters

Independent variables

PL	Part-load, %
P_{in}	Electrical Power input to the system, MW
P_{out}	Electrical Power output of the system, MW
$Q_{TS\max}$	Thermal storage tank capacity, MWh
Q_{TSin}	Heat flow diverted to thermal storage unit, MW
Q_{TSout}	Heat flow extracted from thermal storage unit, MW
y_e	Binary variable for existence of supply units
y_p	Binary variable for power being bought or sold
y_w	Binary variable for 'on'/'off' operational mode
y_{TS}	Binary variable for thermal storage being charged or discharged

Dependent variables

A'	Availability of selected unit, %
$C'_{capital}$	Cost of purchase and installation of selected unit, MM£
C_{Fuel}	Total annual cost of fuel, MM£/yr
$C_{Maint.}$	Total annual maintenance cost, MM£/yr
$C_{Opera.}$	Total annualised operating costs, MM£/yr
C_{Power}	Net annual cost of power (positive when power is imported and negative when power is exported), MM£/yr
C_{Total}	Total annualised costs, MM£/yr
$C_{Tcapital}$	Annualised total capital costs, MM£/yr
LS'	Life span of selected unit, h

M'_{mCO2}	CO_2 production in manufacture of selected unit, $kgCO_2/MWh$
F	Fuel consumption in volume per hour, Nm^3/h or L/h
P	Power output of a supply unit, MW
Q	Thermal output of a supply unit, MW
Q'_T	Thermal output at 100% capacity of selected unit, MW
Q_{TSp}	Heat stored in each time band, MWh

Parameters

a	Slope of the linear fuel consumption function, Nm^3/h or L/h (CHP units)
A	Availability, %
Af	Annualisation factor, yr^{-1}
b	Independent term of the linear fuel consumption function, Nm^3/h or L/h (CHP units)
c	Slope of the linear power output function, MW (CHP units)
C_{capex}	Cost of purchase and installation, £/MW (£/m^3 for thermal storage unit)
c_f	Fuel price per unit volume, £/m^3 or £/L
c_{mf}	Fixed annual maintenance cost, £/yr
c_{mv}	Variable maintenance cost, £/MWh
$c_{Pbought}$	Purchase price for electrical power, £/MWh
c_{Psold}	Sales tariff for electrical power, £/MWh
d	Independent term of the linear power output function, MW (CHP units)
HV	Fuel heating value, MWh/m^3 or MWh/L
IF	Fraction of heat stored with respect to thermal storage tank capacity at start of accumulation period
LS	Life span, h
M_{mCO2}	CO_2 production in manufacture of a supply unit, $kgCO_2/MW$
M_{vCO2}	Variable CO_2 production per volume of fuel burnt, $kgCO_2/Nm^3$ or $kgCO_2/L$
η	Boiler efficiency (heat out per unit of energy input as fuel)
P_D	Electrical power demand, MW
PD	Peak thermal demand, MW

$PL_{\max}$	Maximum part-load of a 'unit type' (e.g. 100%)
$PL_{\min}$	Minimum part-load of a 'unit type' (e.g. 50%)
PL_{int}	Part-load of turbines with supplementary firing at 100% power capacity
P_T	Power output at 100% capacity, MW
Q_D	Thermal demand, MW
Q_T	Thermal output at 100% capacity, MW
T	Hours in a time band, h
ΔT	Difference between water supply and return temperatures, °C

Subscripts

i	Supply unit
p	Time band

Objective function and main equations

The objective function is to minimise the total annualised cost of heat production by the DE solution. This cost is the sum of annualised capital cost, $C_{Tcapital}$, total running costs, C_{Opera}, and net value of electrical power, C_{Power}:

$$\min\{C_{Total} = C_{Tcapital} + C_{Opera.} - C_{Power}\} \tag{1}$$

If there is a net surplus of power, C_{Power} is positive as income is derived from selling power to the grid; conversely, if there is a net deficit of power, C_{Power} is negative due to the cost of buying power from the grid.

The annual system investment cost is the sum of the capital costs of every single unit present in the superset divided by an annualisation factor:

$$C_{Tcapital} = Af \sum_i C_{Capital_i} \tag{2}$$

The annualisation factor allows the initial investment to be spread across the life time of the assets.

Annual running costs, or operating costs, are composed of two main components: fuel cost, C_{Fuel}, and maintenance cost, $C_{Maint.}$:

$$C_{Opera.} = C_{Fuel} + C_{Maint.} \tag{3}$$

Fuel cost is calculated as the accumulative fuel consumption of every supply unit, *i*, in each period, *p*, multiplied by its respective fuel price:

$$C_{Fuel} = \sum_p T_p \left(\sum_i c_{f\,i} F_{ip} \right) \qquad (4)$$

The fuel consumption, *F*, of each unit, along with the thermal output, *Q*, and power output, *P*, are all calculated in different ways depending on the unit type. A binary variable, y_w, is defined for each single unit in order to identify whether it is 'on' or 'off' in each time band. When a unit is 'on', y_w equal to one (1), its part-load can be optimised within a specific range (e.g. minimum load ≤ PL ≤ 100%). In this methodology, part-load (PL) refers to the percentage of heat output from the DE system with respect to its rated (maximum) heat capacity. Equations (5), (6) and (7) are then used to calculate fuel consumption, heat output and power output of CHP units (gas engines, turbines and fuel cells):

$$Q_{ip} = Q_{T\,i} PL_{ip} \qquad \text{for every i, p} \qquad (5)$$

$$F_{ip} = a_i PL_{ip} + b_i y_{wi} \qquad \text{for every i, p} \qquad (6)$$

$$P_{ip} = c_i PL_{ip} + d_i y_{wi} \qquad \text{for every i, p} \qquad (7)$$

Turbines with supplementary firing facilities (duct burners), will have a distinctive performance whether in power production 'mode' or supplementary firing 'mode', modelled by a piece-wise linearisation approach. One semi-continuous variable, PL, and one binary variable, y_w, are defined for each linear section as shown in Figure E.1.

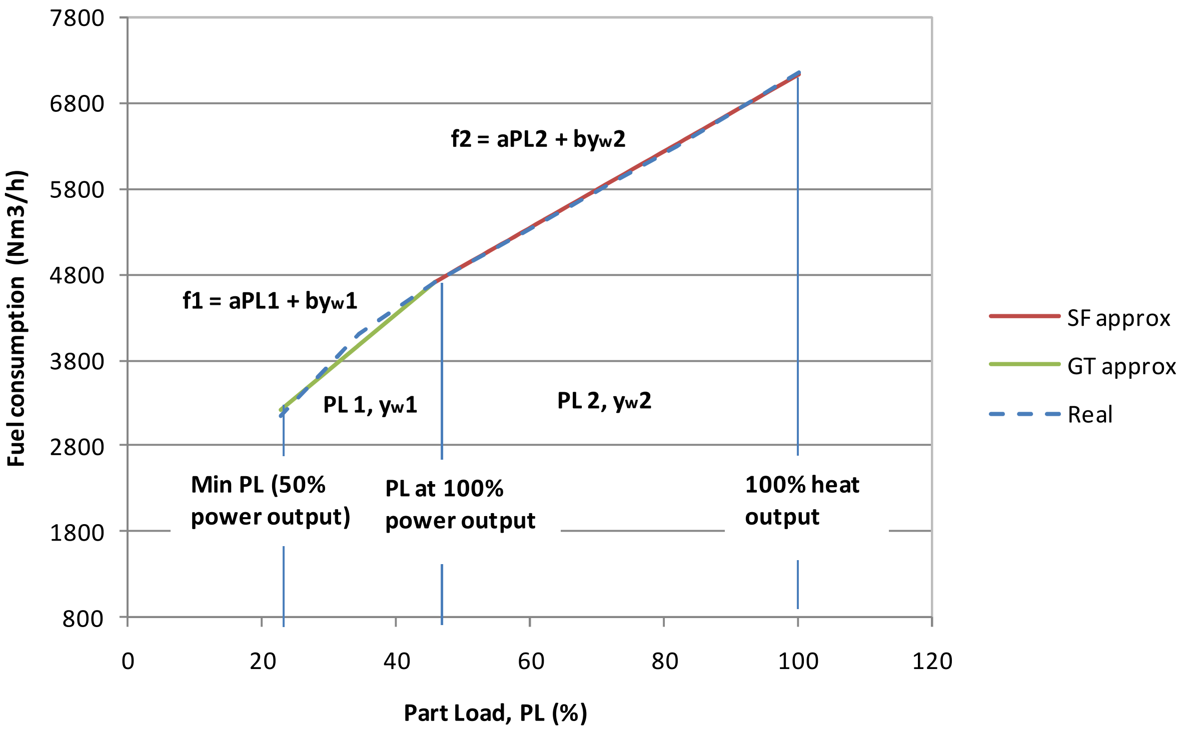

Figure E.1 Piece-wise linear model of fuel consumption for a turbine with supplementary firing (GT: gas turbine; SF: supplementary firing)

Equations (8) to (12) are used to calculate fuel consumption, heat output and power output in turbines with supplementary firing.

$$F_{ip} = \left(a_i PL1_{ip} + b_i y1_{wi}\right) + \left(a'_i \ PL2_{ip} + b'_i \ y2_{wi}\right) \qquad \text{for every i, p} \qquad (8)$$

$$P_{ip} = \left(c_i PL1_{ip} + d_i y1_{wi}\right) + \left(c'_i \ PL2_{IP} + d'_i \ y2_{wi}\right) \qquad \text{for every i, p} \qquad (9)$$

$$PL_{ip} = PL1_{ip} + PL2_{ip} \qquad \text{for every i, p} \qquad (10)$$

$$Q_{ip} = Q_{T\,i} PL_{ip} \qquad \text{for every i, p} \qquad (11)$$

$$y_{wi} = y1_{wi} + y2_{wi} \qquad \text{for every i, p} \qquad (12)$$

Equations (13) and (14) are used to describe the performance of boilers:

$$F_{ip} = \frac{Q_{ip}}{\eta_i HV_i} \qquad \text{for every i, p} \qquad (13)$$

$$Q_{ip} = Q_{T\,i} PL_{ip} \qquad \text{for every i, p} \qquad (14)$$

Maintenance costs are composed of a variable maintenance cost, which depends on the total output of the unit (e.g. MWh of heat produced), and a fixed maintenance cost per year:

$$C_{Maint} = \sum_p T_p \left(\sum_i c_{mv\,i} Q_{ip} \right) + \sum_i c_{mf\,i} \qquad (15)$$

The net value of electrical power sold, described by equation (16), is calculated as a cumulative factor in each time period. The energy centre may either sell or buy power, i.e. it cannot do both at the same time. The variable C_{Power} is positive or negative depending on the amounts of power exported, P_{out}, or imported, P_{in}, in each time band and the tariff structure.

$$C_{Power} = \sum_p T_p \left(c_{Psold\,p} P_{out\,p} - c_{Pbought\,p} P_{in\,p} \right) \qquad (16)$$

Main Constraints

Two of the main constraints of the problem are the system energy balances for power and heat in each time band. The sum of the total electrical power produced within the energy centre and the power imported from the grid, less the power exported to the grid, must be equal to the total electrical power demand, P_D:

$$\sum_i P_{ip} - P_{D\,p} + P_{in\,p} - P_{out\,p} = 0 \qquad \text{for every i, p} \qquad (17)$$

On the other hand, the total heat produced within the energy centre must be equal to or greater than the total heat demand (equation 18). (That is, thermal demand must be met; excess heat may be generated and dumped.)

$$\sum_i Q_{ip} - Q_{D\,p} \geq 0 \qquad \text{for every i, p} \qquad (18)$$

In order to define whether power is being sold or bought; a binary variable, y_P, and a series of constraints must be formulated as follows:

$$0 \leq P_{in\,p} \leq Uy_{p\,p} \qquad \text{for every p} \qquad (19)$$

$$0 \leq P_{out\,p} \leq U\left(1 - y_{p\,p}\right) \qquad \text{for every p} \qquad (20)$$

When y_p is equal to one, power is being bought and P_{out} is reduced to zero. Conversely, when y_p is equal to zero, power is being sold and P_{in} is reduced to zero (U is a number some orders of magnitude larger than power in or out). The difference between the total power produced by the energy centre and the power demand defines the amount of power being sold or bought.

The performance of every supply unit is constrained depending on the type of unit as follows:

CHP units:

$$PL_{ip} - PL_{min}\, y_{w\,ip} \geq 0 \qquad \text{for every i, p} \qquad (21)$$

$$PL_{ip} - PL_{max}\, y_{w\,ip} \leq 0 \qquad \text{for every i, p} \qquad (22)$$

Turbines with supplementary firing:

$$PL1_{ip} - PL_{min}\, y1_{w\,ip} \geq 0 \qquad \text{for every i, p} \qquad (23)$$

$$PL1_{ip} - PL_{\text{int}}\, y1_{w\,ip} \leq 0 \qquad \text{for every i, p} \qquad (24)$$

$$PL2_{ip} - PL_{\text{int}}\, y2_{w\,ip} \geq 0 \qquad \text{for every i, p} \qquad (25)$$

$$PL2_{ip} - PL_{max}\, y2_{w\,ip} \geq 0 \qquad \text{for every i, p} \qquad (26)$$

$$PL_{ip} = PL1_{ip} + PL2_{ip} \qquad \text{for every i, p} \qquad \text{(rep.10)}$$

$$y_{wi} = y1_{wi} + y2_{wi} \qquad \text{for every i, p} \qquad \text{(rep.12)}$$

Boilers:

$$PL_{ip} - PL_{min}\, y_{w\,ip} \geq 0 \qquad \text{for every i, p} \qquad (27)$$

$$PL_{ip} - PL_{max}\, y_{w\,ip} \leq 0 \qquad \text{for every i, p} \qquad (28)$$

When y_w is equal to one, for a particular unit, it means that the unit is 'on' in the time band considered and its part-load is greater than or equal to the minimum allowed. Conversely, when y_p is equal to zero, the unit is 'off' and its part-load thermal output, power output and fuel consumption are all set to zero. This is addressed by constraints (21) to (28).

An extra binary variable, y_e, represents the existence of units. If y_e is equal to one, the unit is selected and exists, and conversely, if y_e is equal to zero, the unit is not selected and does not exist. When y_e is one for a supply unit, its capital cost, fixed maintenance cost, CO_2 production in manufacture, availability and life time must be all considered; otherwise these variables are set to zero. Equations (29) to (34), described the use of y_e

$$C'_{capital\,i} = C_{capexi}\, Q_{T\,i}\, y_{e\,i} \qquad \text{for every i} \qquad (29)$$

$$Q'_{T\,i} = Q_{T\,i}\, y_{e\,i} \qquad \text{for every i} \qquad (30)$$

$$M_m{}'_{CO2\,i} = M_{m\,CO2\,i}\, y_{e\,i} \qquad \text{for every i} \qquad (31)$$

$$A'_i = A_i\, y_{e\,i} \qquad \text{for every i} \qquad (32)$$

$$LS'_i = LS_i\, y_{e\,i} \qquad \text{for every i} \qquad (33)$$

$$y_{w\,ip} - y_{e\,i} \leq 0 \qquad \text{for every i , p} \qquad (34)$$

If a unit is not selected, it does not operate at all; thus y_w is zero for every time band. This is addressed by constraint (34). The converse, that a unit exists but does not operate in any period, is feasible.

Finally, since the objective of the DE solution is to satisfy the thermal demand of each characteristic zone at all times, the sum of the total thermal capacity of boilers must be at least equal to the peak heat demand:

$$\sum_i Q'_{T\,i} - PD \geq 0 \qquad \text{for i = boiler units} \qquad (35)$$

This constraint was formulated as an inequality in order to avoid infeasibilities, where no solution can meet the constraints, arising from the fact that the thermal capacity of each unit is fixed according to the models considered.

Thermal storage unit

The inclusion of thermal storage in the problem generates some changes in the methodology for designing DE solutions with only CHP units and Boilers. Constraint (18) is modified to constraint (36) in order to account for the heat diverted to the thermal storage or extracted from it.

$$\sum_i Q_{ip} - Q_{D\,p} + Q_{TSout\,p} - Q_{TSin\,p} = 0 \qquad \text{for every i, p} \tag{36}$$

The following constraints are also included:

$$0 \le Q_{TSin\,p} \le U y_{TS\,p} \qquad \text{for every p} \tag{37}$$

$$0 \le Q_{TSout\,p} \le U\left(1 - y_{TS\,p}\right) \qquad \text{for every p} \tag{38}$$

The binary variable y_{TS} addresses the operating mode of the Thermal Storage unit. When y_{TS} is equal to one, the thermal storage is being charged. Conversely, when y_{TS} is equal to zero, the thermal storage is discharged. The difference between the total heat produced by the energy centre and the heat demand in each time band, defines the amount of heat being diverted to the thermal storage or extracted from it.

The thermal storage unit is typically charged when the price of electricity is high. It can happen that for the next time band the charging process continues, or that the discharge process starts due to lower electricity prices and/or demand. It is necessary therefore, to include an expression (constraint 39) showing that heat transferred into the accumulator is equal to that recovered from the accumulator during a specified time period (e.g. 24 hours). This constraint is basically an energy balance on the thermal storage.

$$\sum_{p-3}^{p} T_p \left(Q_{TSin\,p} - Q_{TSout\,p}\right) = Q_{TS\,p=0} \qquad \text{for every four periods} \tag{39}$$

$$Q_{TS\,p=0} = IF\left(Q_{TS\max}\right) \tag{40}$$

At the end of a period, p, the remaining capacity of the thermal storage unit is:

$$Q_{TS\,p} = Q_{TS\,p-1} + T_p\left(Q_{TSin\,p} - Q_{TSout\,p}\right) \qquad \text{for every p} \tag{40}$$

$$0 \le Q_{TS\,p} \le Q_{TS\max} \qquad \text{for every p} \tag{41}$$

To allow continuity between week days and weekends, and between one season and the next, constraint (42) must be satisfied.

$$Q_{TS\,p=0} = Q_{TS\,p=4} = Q_{TS\,p=8} = Q_{TS\,p=12} = Q_{TS\,p=16} = Q_{TS\,p=20} = Q_{TS\,p=24} \tag{42}$$

The size of the thermal storage unit, Q_{TSmax}, may be optimised in this way as its capital cost and revenues from extra power sales are accounted for in the model objective function.

Solar Heaters

Solar heaters are supply units, the performance of which is dictated by external factors, rather than human intervention. In the DE system models, the heat output of a solar heater is fixed for each time band according to the solar irradiation of that time. The only

adjustable variable for the evaluation of solar heaters as part of the energy centre is, therefore, their binary variable for existence.
The heat output of solar heaters in time band p is a given parameter, Q_{STOD}, which depends on the heater model (equation 43):

$$Q_{ip} = Q_{STOD\,ip}\, y_{ip} \qquad \text{for every i, p} \qquad (43)$$

When a solar heater is selected to exist it will be active in every time band. Thus, the model for solar heaters does not include binary variables for 'on'/'off' in each time band.

The equations which take into account capital cost, fixed maintenance cost, CO_2 production in manufacture, and availability, are the same as CHP units and boilers. Solar heating units do not have electrical power output, fuel consumption or carbon emissions.

Appendix F – Section 5.1 Case Study Input Data

Demand data for Harrogate 15, a mid-level super output area (MLSOA) of Harrogate in Yorkshire, are used for the test case. The energy demand data are obtained from Deliverable 2.0 and are shown in Tables F.1 and F.2. The annual energy demand is: 148 GWh of heat and 44 GWh of electricity.

Table F.1 Thermal demand (MW) data for Harrogate 15 for week days (Deliverable 2.0)

time band	hours	Winter	Summer	Transition
0500 - 0900	5	44.7	16.1	27.4
1000 - 1600	7	26.4	8.8	16.0
1700 - 2100	5	29.0	11.3	18.2
2200 - 0400	7	13.1	5.2	8.4
baseload		6.7	2.1	4.1
Peak		58.0	21.0	35.0
no. of days		90	122	153

Table F.2 Electrical demand (MW) data for Harrogate 15 week days (Deliverable 2.0)

time band		Winter	Summer	Transition
0500 - 0900	5	4.7	3.3	4.2
1000 - 1600	7	7.6	5.4	6.8
1700 - 2100	5	8.0	5.7	7.2
2200 - 0400	7	3.3	2.4	3.0
baseload		2.4	1.7	2.1
peak		10.0	7.2	9.1
no of. days		90	122	153

The DE system models used are shown in Tables F.3 to F.17. These models are indicative of preliminary supply models for additional types and scales of DE systems reported in Deliverable 3.1.

Gas engines:

Table F.3 Model for Gas Engine 1.12 MWe (Deliverable 3.1)

General	Model	G3516B LE 1MWe		
	Total kWe	1120		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	770		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0085		
Performance	CO_2 manufacture, g/kW	59387		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	306	1120	1250
	75	240	840	938
	50	169	560	625

Table F.4 Model for Gas Engine 3 MWe

General	Model	xxxxxx 3MWe gas engine		
	Total kWe	3000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	400		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0066		
Performance	CO_2 manufacture, g/kW	46793		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	831	3100	3460
	75	654	2325	2595
	50	458	1550	1730

Table F.5 Model for Gas Engine 5 MWe

General	Model	xxxxxx 5MWe gas engine		
	Total kWe	5000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	350		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0040		
Performance	CO2 manufacture, g/kW	36000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	1380	5200	5803
	75	1085	3900	4352
	50	760	2600	2902

Table F.6 Model for Gas Engine 10 MWe

General	Model	xxxxxxx 10 MWe gas engine		
	Total kWe	10000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	300		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0020		
Performance	CO_2 manufacture, g/kW	26000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	2700	10250	11439
	75	2120	7688	8579
	50	1490	5125	5720

Gas Turbines:

Table B.7 Model for Gas Turbine 3 MWe

General	Model	xxxxxx 3MWe gas turbine		
	Total kWe	3000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	900		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0045		
Performance	CO_2 manufacture, g/kW	17000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	1415	3100	7750
	75	1225	2325	5813
	50	935	1550	3875

Table F.8 Model for Gas Turbine 5 MWe

General	Model	xxxxxx 5MWe gas turbine		
	Total kWe	5000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	700		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0040		
Performance	CO_2 manufacture, g/kW	15142		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	2148	5200	11700
	75	1870	3900	8775
	50	1425	2600	5850

Table F.9 Model for Gas Turbine 10 MWe

General	Model	xxxxxxx 10 MWe gas turbines		
	Total kWe	10000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	650		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0035		
Performance	CO_2 manufacture, g/kW	12000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	3885	10250	20500
	75	3380	7687.5	15375
	50	2570	5125	10250

Table F.10 Model for Gas Turbine 15 MWe

General	Model	xxxxxxx 15 MWe gas turbine		
	Total kWe	15000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	600		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0030		
Performance	CO_2 manufacture, g/kW	10000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	5282	15300	26775
	75	4600	11475	20081
	50	3500	7650	13388

Boilers:

Table F.11 Model for Boiler 2 MWth

General	Model	xxxxxxx 2MWth boiler		
	Total kWth	2000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	50		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	200		
	Variable Maintenance Cost, £/kWh	0.001		
Performance	CO_2 manufacture, g/kW	9471		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	240	0	2000
	75	180	0	1500
	50	120	0	1000

Table F.12 Model for Boiler 3 MWth

General	Model	REX 350		
	Total kWth	3500		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.016		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	38.57		
	Expected lifespan, h (average)	262800		
	Footprint (Package), m x m	1.5	2.9	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0001		
Performance	CO_2 manufacture, g/kW	8305.71		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output at 99 deg C, kWth
	100	385.6	0	3500
	75	289.2	0	2625
	50	192.8	0	1750

Table F.13 Model for Boiler 5 MWth

General	Model	xxxxxxx 5MWth boiler		
	Total kWth	5000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	40		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	400		
	Variable Maintenance Cost, £/kWh	0.0006		
Performance	CO_2 manufacture, g/kW	7000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	598	0	5000
	75	449	0	3750
	50	299	0	2500

Table F.14 Model for Boiler 10 MWth

General	Model	xxxxxxx 10 MW boiler		
	Total kWth	10000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	35		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.0004		
Performance	CO_2 manufacture, g/kW	6000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	1196	0	10000
	75	897	0	7500
	50	598	0	5000

Table F.15 Model for Boiler 20 MWth

General	Model	xxxxxxx 20 MW boiler		
	Total kWth	20000		
	Fuel Type	Natural Gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	30		
	Expected lifespan, h (average)	70000		
	Footprint (Package), m x m	4.8	1.8	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	600		
	Variable Maintenance Cost, £/kWh	0.0001		
Performance	CO_2 manufacture, g/kW	5000		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	2393	0	20000
	75	1795	0	15000
	50	1196	0	10000

Fuel Cells:

Table F.16 Model for Fuel Cell 0.4 MWe (Deliverable 3.1)

General	Model	PureCell 400		
	Total kWe	400		
	Fuel Type	Natural gas		
	Fuel heat value, MJ/Nm^3	35.4		
	Cost of energy input, £/Nm^3	0.111		
	Fuel CO_2 generation, kg/Nm^3	1.96		
Capital Costs	Capex (Installed Cost), £/kW	2833		
	Expected lifespan, h (average)	87600		
	Footprint (Package), m x m	8.3	3.4	
	Availability of the Technology , %	95		
Operating Costs	Fixed Maintenance Cost, £/yr	500		
	Variable Maintenance Cost, £/kWh	0.01		
Performance	CO_2 manufacture, g/kW	347004		
	Load, %	Fuel consumption, Nm^3/h	Electrical output, kWe	Thermal output, kWth
	100	104.2	400	450
	75	78.15	300	338
	50	52.1	200	225

Solar Heaters:

Table F.17 Model for Solar Heater 0.1 MWth (Deliverable 3.1)

Model	DF100(30)		
Total kW	100.56		
Fuel Type	Solar Heating		
Capex (Installed Cost), £/kW	1809.8		
Expected lifespan, h (average)	219000		
Footprint (Package), m x m	13	13.83	
Availability , % of the year	98		
Fixed Maintenance Cost, £/yr	500		
Variable Maintenance Cost, £/kWh	0		
CO_2 manufacture, g/kW	2798727		
Heat output with season and time of day, kW	Winter	Summer	Transition
Morning 05.00-09.00	0.31	26.75	10.22
Afternoon 09.00-16.00	24.02	91.23	59.03
Evening 16.00-24.00	1.50	20.68	8.98
Night 24.00-05.00	0.00	0.02	0.00

Appendix G – Section 5.2 Existing DE Solution

Tables G.1, G.2, G.5 and G.6 compare the operational optimisation results for a monthly approach and a seasonal approach for different suite configurations (with/without thermal storage; different engines selected) and different ‘peak power sales tariff to fuel prices’ ratios. This first set of results was obtained for the original definition of seasons: Winter: January, February and March; Spring: April, May and June; Summer: July, August, and September; and Autumn: October, November, December.

Tables G.3, G.4, G.7 and G.8 show the operational optimisation results with a monthly approach and a seasonal approach for another definition of seasons: Winter: November, December, January, February and March; Spring: April and May; Summer: June, July and August; and Autumn: September and October. The same suite configurations and ‘peak power sales tariff to fuel prices’ ratios as the previous case were considered.

Table G.1. Results with a seasonal approach vs. a monthly approach for a **ratio of 3.5** and **NO** thermal storage **(original seasons)**

	1.35 MWe			**1.12 MWe**			**0.85 MWe**			**No engine**		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	13,091	12,556	4.26	14,511	14,244	1.87	12,766	11,142	14.58	9,054	9,056	-0.02
Power production, MWh	2,503	2,171	15.29	3,298	3,135	5.20	2,221	1,248	77.96	0	0	-
Heat production, MWh	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0.00
Capital cost, £	176849			163165			148794			42587		
Operating Costs, £	174,408	165,968	5.09	196,877	192,651	2.19	170,260	144,180	18.09	110,656	110,672	-0.01
Revenues from power, £	-70,403	-61,952	13.64	-91,724	-87,406	4.94	-62,107	-36,032	72.37	0	0	-
Total annualised costs, £/y	**280,854**	**280,865**	**0.00**	**268,319**	**268,411**	**-0.03**	**256,947**	**256,942**	**0.00**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**1,404**	**1,458**	**-3.70**	**1,303**	**1,328**	**-1.93**	**1,476**	**1,623**	**-9.06**	**1,811**	**1,811**	**-0.02**

Table G.2. Results with a seasonal approach vs. a monthly approach for a **ratio of 3.5** with use of **thermal storage (original seasons)**

	1.35 MWe			**1.12 MWe**			**0.85 MWe**			**No engine**		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	15,427	15,264	1.07	15,333	15,244	0.58	12,804	11,180	14.53	9,054	9,056	-0.02
Power production, MWh	3,928	3,827	2.64	3,771	3,717	1.45	2,221	1,248	77.96	0	0	-
Heat production, MWh	8,486	8,486	0.00	8,486	8,486	0.00	8,486	8,486	0.00	8,451	8,451	0.00
Capital cost, £	176,849			163,165			148,794			42,587		
Operating Costs, £	211,155	208,584	1.23	209,718	208,293	0.68	170,719	144,638	18.03	110,656	110,672	-0.01
Revenues from power, £	-109,317	-106,648	2.50	-104,478	-102,982	1.45	-62,107	-36,032	72.37	0	0	-
Total annualised costs, £/y	**278,687**	**278,785**	**-0.04**	**268,406**	**268,477**	**-0.03**	**257,406**	**257,400**	**0.00**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**1,180**	**1,197**	**-1.37**	**1,238**	**1,246**	**-0.67**	**1,484**	**1,631**	**-9.02**	**1,811**	**1,811**	**-0.02**

Table G.3. Results with a seasonal approach vs. a monthly approach for a **ratio of 3.5** and **NO** thermal storage **(Seasons acc. to tariff)**

	1.35 MWe			1.12 MWe			0.85 MWe			No engine		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	12,260	12,556	-2.36	14,270	14,244	0.18	11,141	11,142	-0.01	9,054	9,056	-0.02
Power production, MWh	1,988	2,171	-8.43	3,156	3,135	0.67	1,249	1,248	0.08	0	0	-
Heat production, MWh	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0
Capital cost, £	176849			163165			148794			42587		
Operating Costs, £	161,280	165,968	-2.82	193,172	192,651	0.27	144,167	144,180	-0.01	110,656	110,672	-0.01
Revenues from power, £	-57,151	-61,952	-7.75	-87,999	-87,406	0.68	-36,057	-36,032	0.07	0	0	-
Total annualised costs, £/yr	**280,978**	**280,865**	**0.04**	**268,338**	**268,411**	**-0.03**	**256,904**	**256,942**	**-0.01**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**1,406**	**1,458**	**-3.57**	**1,327**	**1,328**	**-0.08**	**1,625**	**1,623**	**0.12**	**1,811**	**1,811**	**-0.02**

Table G.4. Results with a seasonal approach vs. a monthly approach for a **ratio of 3.5** with use of **thermal storage (Seasons acc. to tariff)**

	1.35 MWe			1.12 MWe			0.85 MWe			No engine		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	15,317	15,264	0.35	15,346	15,244	0.67	11,179	11,180	-0.01	9,054	9,056	-0.02
Power production, MWh	3,860	3,827	0.86	3,779	3,717	1.67	1,249	1,248	0.08	0	0	-
Heat production, MWh	8,486	8,486	0.00	8,486	8,486	0.00	8,486	8,486	0.00	8,451	8,451	0
Capital cost, £	176849			163165			148794			42587		
Operating Costs, £	209,429	208,584	0.41	209,926	208,293	0.78	144,626	144,638	-0.01	110,656	110,672	-0.01
Revenues from power, £	-107,601	-106,648	0.89	-104,703	-102,982	1.67	-36,057	-36,032	0.07	0	0	-
Total annualised costs, £/yr	**278,677**	**278,785**	**-0.04**	**268,388**	**268,477**	**-0.03**	**257,363**	**257,400**	**-0.01**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**1,181**	**1,197**	**-1.34**	**1,237**	**1,246**	**-0.72**	**1,633**	**1,631**	**0.12**	**1,811**	**1,811**	**-0.02**

Table G.5. Results with a seasonal approach vs. a monthly approach for a **ratio of 6.2** and **NO** thermal storage **(original seasons)**

	1.35 MWe			1.12 MWe			0.85 MWe			No engine		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	17,931	16,744	7.09	21,326	20,666	3.19	20,439	19,977	2.31	9,054	9,056	-0.02
Power production, MWh	5,505	4,768	15.46	7,416	7,015	5.72	6,812	6,534	4.25	0	0	-
Heat production, MWh	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0.00
Capital cost, £	176,849			163,165			148,794			42,587		
Operating Costs, £	250,839	232,085	8.08	304,538	294,101	3.55	293,457	286,042	2.59	110,656	110,672	-0.01
Revenues from power, £	-236,573	-206,524	14.55	-315,661	-298,424	5.78	-284,259	-273,283	4.02	0	0	-
Total annualised costs, £/yr	**191,115**	**202,410**	**-5.58**	**152,043**	**158,842**	**-4.28**	**157,992**	**161,553**	**-2.20**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**916**	**1,036**	**-11.58**	**668**	**731**	**-8.55**	**784**	**826**	**-5.13**	**1,811**	**1,811**	**-0.02**

Table G.6. Results with a seasonal approach vs. a monthly approach for a **ratio of 6.2** with use of **thermal storage (original seasons)**

	1.35 MWe			1.12 MWe			0.85 MWe			No engine		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	19,715	19,620	0.48	22,071	21,513	2.59	20,404	19,910	2.48	9,054	9,056	-0.02
Power production, MWh	6,588	6,527	0.93	7,844	7,504	4.53	6,769	6,472	4.59	0	0	-
Heat production, MWh	8,486	8,486	0.00	8,486	8,486	0.00	8,486	8,486	0.00	8,451	8,451	0.00
Capital cost, £	176,849			163,165			148794			42,587		
Operating Costs, £	278,881	277,368	0.55	316,182	307,351	2.87	292,757	284,813	2.79	110,656	110,672	-0.01
Revenues from power, £	-297,876	-295,804	0.70	-338,753	-325,465	4.08	-286,892	-276,533	3.75	0	0	-
Total annualised costs, £/yr	**157,854**	**158,413**	**-0.35**	**140,595**	**145,052**	**-3.07**	**154,659**	**157,074**	**-1.54**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**748**	**758**	**-1.40**	**610**	**663**	**-8.04**	**798**	**843**	**-5.37**	**1,811**	**1,811**	**-0.02**

Table G.7. Results with a seasonal approach vs. a monthly approach for a **ratio of 6.2** and NO thermal storage **(Seasons acc. to tariff)**

	1.35 MWe			1.12 MWe			0.85 MWe			No engine		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	16,023	16,744	-4.31	20,902	20,666	1.14	20,133	19,977	0.78	9,054	9,056	-0.02
Power production, MWh	4,321	4,768	-9.38	7,160	7,015	2.07	6,629	6,534	1.45	0	0	-
Heat production, MWh	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0.00	8,451	8,451	0
Capital cost, £	176849			163165			148794			42587		
Operating Costs, £	220,711	232,085	-4.90	297,841	294,101	1.27	288,547	286,042	0.88	110,656	110,672	-0.01
Revenues from power, £	-188,302	-206,524	-8.82	-304,595	-298,424	2.07	-277,479	-273,283	1.54	0	0	-
Total annualised costs, £/yr	**209,258**	**202,410**	**3.38**	**156,411**	**158,842**	**-1.53**	**159,862**	**161,553**	**-1.05**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**1,098**	**1,036**	**5.98**	**706**	**731**	**-3.42**	**808**	**826**	**-2.18**	**1,811**	**1,811**	**-0.02**

Table G.8. Results with a seasonal vs. a monthly approach for a **ratio of 6.2** with use of **thermal storage (Seasons acc. to tariff)**

	1.35 MWe			1.12 MWe			0.85 MWe			No engine		
	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)	Three seasons	12 Months	Difference (%)
Fuel consumption, MWh	20,038	19,620	2.13	21,455	21,513	-0.27	20,125	19,910	1.08	9,054	9,056	-0.02
Power production, MWh	6,788	6,527	4.00	7,471	7,504	-0.44	6,602	6,472	2.01	0	0	-
Heat production, MWh	8,486	8,486	0.00	8,486	8,486	0.00	8,486	8,486	0.00	8,451	8,451	0
Capital cost, £	176849			163165			148794			42587		
Operating Costs, £	283,975	277,368	2.38	306,453	307,351	-0.29	288,279	284,813	1.22	110,656	110,672	-0.01
Revenues from power, £	-303,022	-295,804	2.44	-326,643	-325,465	0.36	-281,427	-276,533	1.77	0	0	-
Total annualised costs, £/yr	**157,802**	**158,413**	**-0.39**	**142,975**	**145,052**	**-1.43**	**155,646**	**157,074**	**-0.91**	**153,243**	**153,259**	**-0.01**
CO_2 total emissions, t/yr	**702**	**758**	**-7.39**	**665**	**663**	**0.30**	**820**	**843**	**-2.73**	**1,811**	**1,811**	**-0.02**