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Carbon constrained design of energy infrastructure for new build schemes

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HIGHLIGHTS

- An optimised design model was developed for new build energy distribution schemes.
- The carbon constrained design was examined for a real case study at Ebbw Vale, UK.
- The carbon constraint significantly increases the cost of build to the developer.
- The optimal design and cost were shown to be sensitive to the year of construction.
- The method used to evaluate grid electricity emissions impacts the optimal design.

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ABSTRACT

The carbon constrained design of energy supply infrastructure for new build schemes was investigated. This was considered as an optimization problem with the objective of finding the mix of on-site energy supply technologies that meet green house gas emissions targets at a minimum build cost to the developer. An integrated design tool was developed by combining a social cognitive optimisation solver, an infrastructure model and a set of analysis modules to provide the technical design, the evaluation of greenhouse gas emissions and the financial appraisal for the scheme. The integrated design tool was applied to a new build scheme in the UK with a 60% target reduction of regulated emissions. It was shown that the optimal design and corresponding cost was sensitive to the year of build completion and to the assumptions applied when determining the emissions intensity of the marginal central generators.

1. Introduction

The reduction of energy related emissions from buildings is expected to provide a significant contribution to the emissions targets set by UK energy policy. Part of this effort includes the elimination of emissions from the operation of new build schemes by appropriate planning and design. One approach is to reduce energy consumption through improved use of building construction and material standards. Recent initiatives such as the code for sustainable homes (CSHs) [1] provide developers with a framework for the construction of domestic dwellings, and similar schemes have been mooted for the non-domestic sector [2]. Achieving significant emissions savings solely by improving the building fabric is however expensive and often impractical. An additional approach is to move away from the established practice of using natural gas boilers for the provision of heat and grid supplied electricity for appliances, lighting and cooling. Several low carbon or renewable technology options are available to developers and the challenge is to identify the appropriate choice for each scheme. This combined approach is mirrored by the emergence of whole scheme planning initiatives such as the zero carbon homes [3].

A cost effective design of low carbon energy supply systems requires an understanding of the technical implications of using each available technology, an appraisal of the cost and financial viability of the development, and an assessment of the energy related emissions for the scheme. Building level technologies such as heat pumps and solar PV can have a significant effect upon electricity demand and the design of the electricity distribution network as examined in [4,5]. Other technologies such as solar thermal panels can be used to supply heat [6]. These technologies may also be combined as hybrid systems that consist of two or more renewable heating or electricity supply technologies to meet the overall energy demand, as examined by [7]. Life cycle assessment (LCA) is used to compare alternative designs that have higher initial costs but lower operating-related costs over the project life span than the lower-initial-cost design. LCA was performed in building integrated design by [8,9] to investigate and evaluate the total cost of ownership and environmental impacts of maintaining the infrastructure and service over its lifetime. At the community level,

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Nomenclature

A	area (m^2)
c	unit cost (£/unit)
C	total cost or value (£)
CEF	emissions intensity of grid supplied electricity (tCO_2e/kW h)
CoP	coefficient of performance (dimensionless)
ε	fuel emissions intensity (tCO_2e/kW h)
ξ	annual or total emissions (tCO_2e)
η	process efficiency (dimensionless)
f	fraction of occupied floor space served by heating appliance
F	fuel energy consumption rate (kJ/s)
K	heat recovery effectiveness (dimensionless)
N	number of units (dimensionless)
NPV	net present value (£)
Φ	heat supply or demand (kW_{th})
P	electrical power generation or demand (kW_{el})
T	temperature (°C)

Subscripts/superscripts

Air	property of outside air
ADMD	after diversity maximum demand
AL	appliance and lighting
ASHP	air source heat pump
Ave	average
B	building
c	cluster
CHP	combined heat and power
d	representative day
DHW	domestic hot water
DHN	district heating network
Dmd	demand
E	network element
Elec	electricity
ElGen	electrical generation
EN	electricity network
Fconv	fuel conversion process
g	generation plant
G	energy centre generation plant
GCH	gas central heating
GN	gas network
GSHP	ground source heat pump
Ground	property of ground
HAcc	heat accumulator
HE	heat exchanger
HP	heat pump
Inf	infrastructure
L	lighting
Max	maximum
Min	minimum
n	network node
NGB	natural gas boiler
p	time period
Ref	reference case
Reg	regulated
Roof	building roof space
SC	space cooling
Sink	heat sink
SH	space heating
SolT	solar thermal panels
PV	photovoltaic panels

district heating is a potential means of using local heat sources. This technology is used widely in regions with cold winters such as Northern and Eastern Europe, North East Asia and Canada and the design of such schemes is supported by a wealth of research, as in [10,11].

A number of researchers have considered a whole scheme approach to energy supply infrastructure design over the years. Refs. [12] and [13], for example, examined the integrated design of combined district heat and electricity networks. Ref. [14] provides a more generalised multi-carrier approach with hydrogen, natural gas, electricity, district heating and district cooling all considered as options. In most of these cases, the appraisal of cost is considered using a relatively simple single actor financial model. However, future community schemes are likely to consist of complex multi-actor and multi-objective organisational structures as discussed in [15].

The carbon constrained design of new schemes through initiatives such as the Zero Carbon Homes [3] requires a detailed analysis of energy related GHG emissions at the planning stage. Different approaches to planning energy systems subjecting to carbon constraints have been reported in [16–18]. These studies investigate energy resource planning for low carbon energy system design. Several researchers [19] consider the emissions performance of energy supply technologies implemented at distribution level. Of particular importance is the dependence of the performance of technologies such as heat pumps, PV and combined heat and power upon the emissions intensity of electricity supplied by the grid [20].

This paper presents an integrated design tool that determines the optimal cost mix of energy supply technologies for a scheme subject to local emissions reduction targets. The tool models the interactions between the energy supply technologies installed at each building, the technical design of the local energy infrastructure, the greenhouse gas emissions resulting from energy use and the financial performance of the scheme. An example case study was used to illustrate the application of the tool for the carbon constrained energy infrastructure design of a UK community. The cost of investment, the viability of a public sector energy services company and the cost of energy supply to each consumer were considered within the financial model. The interaction between the design of the scheme and the projection of emissions associated with grid supplied electricity was also examined.

2. Problem description

Problem of the optimal design of energy supply schemes for new build communities, adhering to carbon emission constraints was considered. The optimisation objective was to minimise the cost of build to the developer, C_{Inf} whilst delivering the on-site infrastructure design constraints, including carbon emissions targets. The optimisation variables were chosen to define the type and capacity of the energy supply technologies installed at the new build scheme. These included the type of heating appliance used within each building; the installed area of photovoltaic and solar heating panels; and the maximum heat output of the generation plant used to supply a district heat network if required. The structure of the integrated optimisation design tool used to solve this problem is shown by Fig. 1.

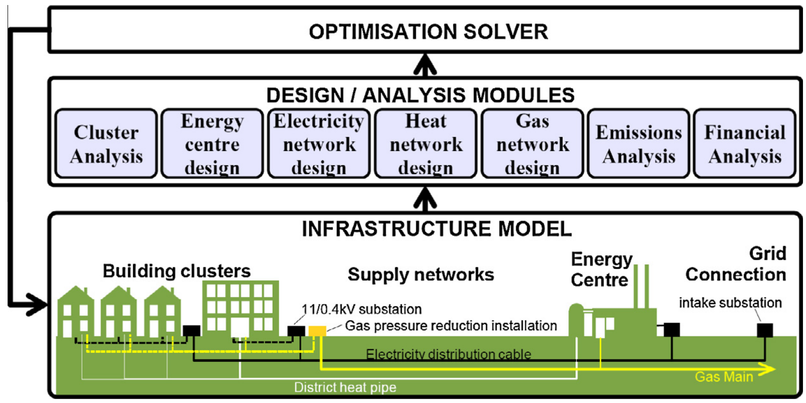

Fig. 1. Structure of the integrated design tool.

The infrastructure model was used to represent the physical layout of the scheme and simulate the performance of the scheme over time. This model included: the location, size and type of each building; the community energy centre; the gas, electricity and heat distribution networks; and the connection of each network to any existing infrastructure. A set of analysis modules was used to evaluate the scheme design at each iteration of the optimisation. The optimisation solver was used to evaluate adherence to any design constraints; to determine whether convergence to an optimal solution has occurred; and to select new values for the optimisation variables until convergence is achieved.

3. Infrastructure model and analysis

3.1. Building cluster modeling

The spatial aspect of a new build scheme was modelled by grouping buildings into N_c sets referred to herein as *building clusters*. Each building cluster was defined by a geographical area A_c containing N_B buildings of identical occupancy type, occupied floor area A_B and available roof space A_{Roof}. The fraction of building floor space supplied by each available type of heating technology, the installed area of solar thermal panels and the installed area of photovoltaic panels were defined for each building cluster. To model the temporal aspect of the scheme, each year was divided into a set of N_d representative days each further sub divided into discreet N_p time periods of length 24/Np. The energy demand was assumed to be constant within each time period.

3.2. Energy centre modelling

The community energy centre was modelled as a set of N_G heat generation units connected to the heat network via a single stratification type heat accumulation tank [21]. Each generation unit was defined by its plant type (CHP or heat only boiler), fuel type, rated heat output, rated power generation, and rated fuel consumption. The heat accumulation tank was defined by its total volume, hot water storage temperature, cold water temperature, heat flow into/out of tank, and total heat stored at each time step.

3.3. Energy supply technology modelling

The scope of this paper was limited to energy technologies that may be supplied by the existing natural gas and electricity networks or by renewable resources available on site. This includes natural gas boilers, natural gas combined heat and power, ground source and air source heat pumps, solar PV and solar thermal hot water as possible generation technologies and district heating as a possible distribution network option. Technologies requiring the development of new fuel supply chains such as biomass or energy from waste were considered beyond the scope of this work.

3.3.1. Natural gas boilers

Natural gas boilers were modelled as a simple fuel to heat conversion of the form:

$$F_{NGB} = \frac{\Phi_{NGB}}{K_{HE}\eta_{NGB}} \tag{1}$$

3.3.2. Natural gas combined heat and power

The use of natural gas combined heat and power (CHP) as the primary heat source for the district heat network was considered. For community scale developments (up to ~5 MW_{el}), internal combustion engines (ICE) are the most suitable CHP technology due to their high efficiencies, high reliability and relatively low capital and maintenance costs [22]. The relationship between the heat output, the fuel consumption and the power generated was modelled using:

$$F_{CHP} = \frac{\Phi_{CHP}}{\eta_{Fconv}K_{HE}(1-\eta_{Elec})} \tag{2}$$

$$P_{CHP} = \frac{\eta_{Elec}\Phi_{CHP}}{K_{HE}(1-\eta_{Elec})} \tag{3}$$

All electricity generated by the CHP plant was assumed to be exported to the local distribution network. The fuel to electricity conversion efficiency was modelled as an empirical function of the plant size (Fig. 2). Data for construction of Fig. 2 was obtained from manufacturer websites [23–26]:

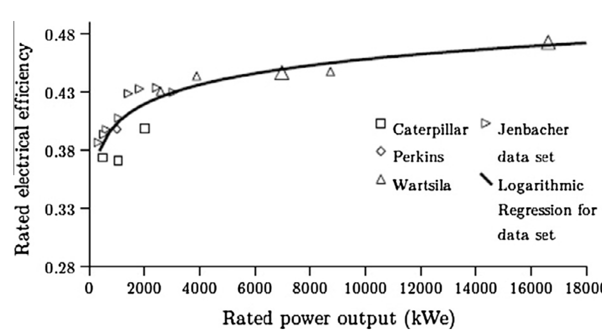

Fig. 2. Variation of rated power output against rated electrical efficiency for natural gas internal combustion engine CHP [23–26].

$$\eta_{Elec} = 0.024 \ln(P_{CHP,max}) + 0.239 \quad (4)$$

3.3.3. Heat pumps

The relationship between the heat generated and the electrical energy consumed by heat pumps was modelled using:

$$P_{HP} = \Phi_{HP} / CoP_{HP} \quad (5)$$

where CoP_{HP} is the heat pump coefficient of performance which varies as a function of the difference between the temperature at the heat source and at the sink. The following relationships were obtained using collated manufacturers data [27]:

$$\begin{aligned} CoP_{GSHP} &= -0.11(T_{Sink} - T_{Ground}) + 8.51 \\ CoP_{ASHP} &= -0.07(T_{Sink} - T_{Air}) + 5.83 \end{aligned} \quad (6)$$

3.3.4. PV and solar thermal generation

Solar photovoltaic and solar thermal hot water panels were both modelled as passive generation technologies by defining a peak generation output and annual generation profile per unit panel area. The relative daily generation profile shown by Fig. 3 and the seasonality factors shown by Table 1 were used to derive an annual generation profile with a total annual generation output of 1 kW h/year. The generation profile for each solar technology was modelled by multiplying each time step of the normalised profile by the total annual generation per unit installed area. [28].

3.4. Energy demand

Daily energy consumption profiles were defined per unit floor area for each building occupancy type. Five types of end use consumption were considered: space heating, domestic hot water, space cooling, appliance and lighting and cooking. Data from Refs. [30,31] was used for energy consumption profiles and seasonality factors provided by Refs. [32,33] were used to scale the profile for each representative day in the year. The energy consumption profiles of each building cluster were thus obtained by multiplying the appropriate profile by the building floor space and number of buildings per cluster over all time steps. The peak, minimum and annual profile of the demand upon the electricity, gas and district heat networks were also defined. These were evaluated by the cluster analysis module as described in Section 3.6.

3.5. Distribution network modelling

3.5.1. Electricity network

The electricity distribution network was modelled as shown in Fig. 4. The network consists of $N_{EN,n}$ busbars interconnected by $N_{EN,e}$ network elements representing either an 11/0.4 kV transformer or a 3-phase underground cable. The parameters used to define the network are detailed in Table 2. The extension of the network into each building cluster was modelled using a generic layout consisting of a set of 11/0.4 kV substations interconnected

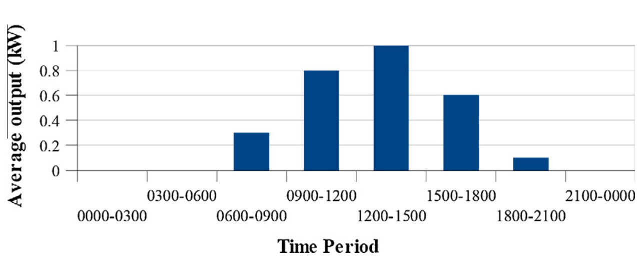

Fig. 3. Relative generation profile used to model the daily output of photovoltaic and solar hot water panels [28].

Table 1
Seasonality factors used to model annual variation of photovoltaic and solar hot water production [29].

Month	Solar generation factor	Month	Solar generation factor
January	0.15	July	0.98
February	0.19	August	0.95
March	0.47	September	0.88
April	0.67	October	0.3
May	0.97	November	0.17
June	1	December	0.11

by 11 kV cable, and a set of low voltage (LV, 0.4 kV) feeders. The actual building cluster network was determined by the number of 11/0.4 kV substations, N_{SS}, and number of feeders per substation, N_{Feed}, required at each building cluster. These also determined the length of each section of cable and the load at each busbar within each cluster. The design of the electricity network was performed by the electricity design module described in Section 3.8.

3.5.2. Gas and district heat networks

The natural gas network was modelled as a graph consisting of $N_{GN,n}$ nodes interconnected by $N_{GN,e}$ network elements. Each network element represented either a polyethylene gas pipe or a medium pressure to low pressure reduction installation. The district heat network was modelled as a dual pipe system hydraulically isolated from the generation plant and consumers by heat exchangers. This was modelled as a radial system of $N_{DHN,n}$ nodes interconnected by $N_{DHN,e}$ elements. Each element represented both the supply and return line of the dual pipe system. Each node represented either a joint between network pipes or a heat exchanger interconnecting the supply and return lines. The gas and district heat networks within each cluster were modelled using the generic topology shown by Fig. 5.

3.6. Cluster analysis module

The cluster analysis module was used to determine the peak demand and minimum demand, and demand profiles for the electricity, gas and district heating networks at each building cluster.

3.6.1. Cluster electricity demand

The electricity demand for each building cluster consisted of the sum of the appliance and lighting load, the cooling load, the electricity based heat provision and the generation from PV panels. The cluster demand at each time step was therefore given by:

$$P^{(c,p)}_{Dmd} = N^{(c)}_B \left(A^{(c)}_B \left(P^{(c,p)}_{AL} + P^{(c,p)}_{SC} + \left(\frac{f^{(c,p)}_{GSHP}}{CoP^{(c,p)}_{GSHP}} + \frac{f^{(c)}_{ASHP}}{CoP^{(c,p)}_{ASHP}} \right) \left(\Phi^{(c,p)}_{SH} + \Phi^{(c,p)}_{DHW} \right) \right) - A^{(c)}_{PV} P^{(p)}_{PV} \right) \quad (7)$$

The peak electricity demand at each cluster depended on the building occupancy type. For non-domestic premises, the peak was estimated as the sum of the peak equipment, lighting, and electric space heating demands:

$$P^{(c)}_{Max} = A^{(c)}_B N^{(c)}_B \left(P^{(c)}_{AL,Max} + \left(\frac{f^{(c)}_{GSHP}}{\left(COP^{(c)}_{GSHP}\right)_{Min}} + \frac{f^{(c)}_{ASHP}}{\left(COP^{(c)}_{ASHP}\right)_{Min}} \right) \left(\Phi^{(c,p)}_{SH,Max} + \Phi^{(c,p)}_{DHW,Max} \right) \right) \quad (8)$$

For domestic premises, a rule of thumb defined within the Central Networks network design manual was adopted:

$$P^{(c)}_{Max} = A^{(c)}_B N^{(c)}_B \left(P^{(c)}_{AL,ADMD} + 0.5 \left(\frac{f^{(c)}_{GSHP}}{\left(COP^{(c)}_{GSHP}\right)_{Min}} + \frac{f^{(c)}_{ASHP}}{\left(COP^{(c)}_{ASHP}\right)_{Min}} \right) \left(\Phi^{(c,p)}_{SH} + \Phi^{(c,p)}_{DHW} \right)_{ADMD} \right) \quad (9)$$

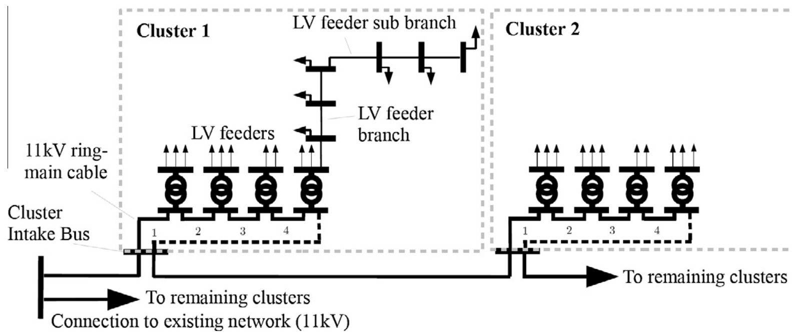

Fig. 4. Generic network topology used to model intra-cluster 11 kV and 0.4 kV electricity distribution networks.

Table 2
Parameters defined at nodes and edges for distribution networks.

	Node	Edge
Gas	Gas demand (kW) Gas pressure(Pa)	Gas flow rate (m^3/s) Gas density (kg/m^3) Pipe diameter (m) Pipe length (m) Pipe roughness
Electricity	Electricity demand (kW) Electricity generation(kW) Voltage (V)	Cable rating (A) Current (A) Impedance (Ω) Power flow (kW) Transformer rating (kW)
District Heat	Heat demand (kW) Pressure (Pa) Return temperature (K) Supply temperature (K)	Ambient temperature (K) Density (kg/m^3) Flow rate (kg/s) Insulation thermal resistance (m^2 K/W) Insulation thickness (m) Pipe diameter (m) Pipe length (m) Pipe roughness Viscosity (Pa s)

The electricity after diversity maximum demand (ADMD) was modelled using the empirical relationship defined within the Central Networks design manual [34]. A similar empirical model for the domestic heating ADMD was obtained from IGEM guidance [35]. The minimum electricity demand at each cluster P_{Min} was determined using:

$$P_{Min}^{(c)} = N_B^{(c)}\left(A_B^{(c)}P_{AL,Min}^{(c)} - A_{PV}^{(c)}P_{PV,Max}\right) \tag{10}$$

3.6.2. Cluster gas demand

The average gas demand was defined by:

$$F_{NG}^{(c,p)} = A_B^{(c)}N_B^{(c)}f_{NGB}^{(c)}\left(\Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)}\right)/\eta_{Fconv,NGB} \tag{11}$$

The peak gas demand of non-domestic premises was determined by:

$$\Phi_{DHN,Max}^{(c)} = f_{NGB}^{(c)}\left(\Phi_{SH,Max}^{(c,p)} + \Phi_{DHW,Max}^{(c,p)}\right)/\eta_{Fconv,NGB}^{(c)} \tag{12}$$

and for domestic dwellings by:

$$\Phi_{DHN,Max}^{(c)} = f_{NGB}^{(c)}\left(\Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)}\right)_{ADMD}/\eta_{Fconv,NGB}^{(c)} \tag{13}$$

3.6.3. Cluster district heat demand

The average district heat was modelled using:

$$\Phi_{DHN}^{(c,p)} = A_B^{(c)}N_B^{(c)}f_{DHN}^{(c)}\left(\Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)}\right) \tag{14}$$

The peak heat demand at non-domestic dwellings was determined by:

$$\Phi_{DHN,Max}^{(c)} = f_{DHN}^{(c)}\left(\Phi_{SH,Max}^{(c,p)} + \Phi_{DHW,Max}^{(c,p)}\right) \tag{15}$$

and for domestic dwellings by:

$$\Phi_{DHN,Max}^{(c)} = f_{DHN}^{(c)}\left(\Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)}\right)_{ADMD} \tag{16}$$

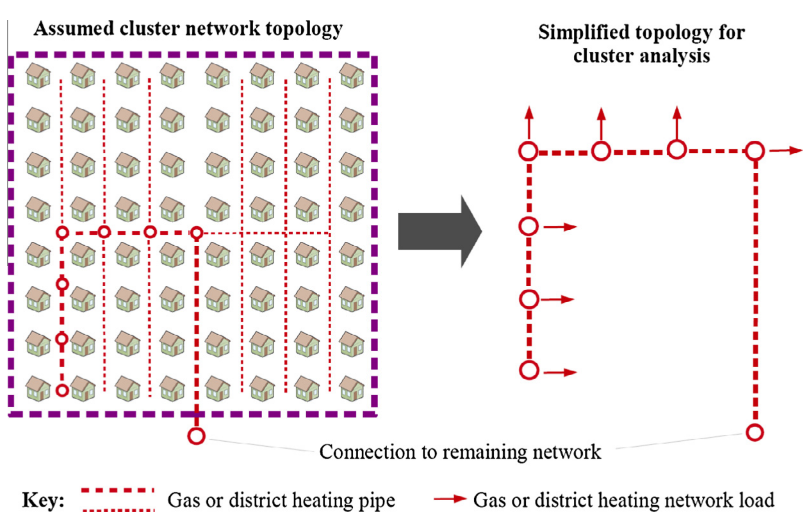

Fig. 5. Topology used to model the natural gas network and the district heating network within each cluster.

3.7. Energy centre design module

The maximum heat output of each generation plant within the energy centre was used as an optimisation variable. The corresponding electrical power output, fuel consumption, energy conversion efficiency and capital cost was determined by the energy centre design module.

3.8. Distribution network design modules

A set of modules were used to design the electricity, gas and district heat networks required within the scheme:

3.8.1. Electricity network design module

A two-stage algorithm was used to design the electricity distribution network. The first stage determined the minimum number of 11/0.4 kV transformers per cluster, the number of 0.4 kV feeders per transformer and the size of each section of 0.4 kV cable so that:

- The maximum power across each transformer does not exceed the rated power of the largest available transformer size.
- The maximum feeder current does not exceed the rated current of the largest available cable size.
- And the voltage tolerance of (+10%/−6%) for the LV network is not breached at any busbar [34].

The second stage selected the 11 kV cable sizes required to ensure adherence to voltage tolerance and rated cable currents. To consider the effect of reverse power flows, the combination of maximum energy centre electricity generation and minimum cluster electricity demand was considered. A radial steady state load flow algorithm was used at each stage to evaluate network voltages and cable currents.

3.8.2. Gas network design module

The gas network design module was used to determine the diameter of each section of pipe and the rated capacity of each pressure reduction installation. A radial gas load flow algorithm was used to determine the minimum diameter required at each pipe by ensuring:

- A minimum pressure of 0.5 bar within medium pressure networks [35].
- A minimum pressure of 22.5 mbar within low pressure networks [35].
- A maximum flow velocity of 20 m/s [35].

3.8.3. District heating network design module

The diameter of each section of district heating pipe was determined by the district heating design module. A district heat load flow algorithm was used to evaluate the pressure drop and heat losses at each pipe. Pipe diameters were determined by first specifying the smallest available diameter at each pipe and then increasing the diameter of the pipe with the highest pressure drop until a maximum head constraint of 14 bar [36] was met at the point of supply.

3.9. Energy centre supply schedule analysis

A rule based algorithm was used to determine the generation schedule of the energy centre plant. It was assumed that all heat was supplied to the district heat network via the heat storage tank. For each representative day, the cost of operation for each generation unit at each time period was determined. The generation plant were then dispatched in order of increasing cost until:

$$\sum \Phi_{HAcc,In} = \sum \Phi_{HAcc,Out} \tag{17}$$

where $\Phi_{HAcc,In}$ and $\Phi_{HAcc,Out}$ are the heat flow into and out of the accumulator respectively. The size of the accumulator was calculated as the maximum of the capacities required at each representative day.

3.10. Financial analysis module

The financial analysis module determined the capital cost of the energy infrastructure, the revenues obtained from on-site generation and the costs associated with on-site consumption. These were used to assess the financial performance of each actor within the scheme. The detail of the ownership and organisational structure will vary from scheme to scheme and a flexible modelling approach was applied. A detailed financial model is described within Section 4.

3.11. Emissions analysis module

Emissions analysis module was used to determine the carbon emissions resulting from the provision of energy to a scheme. Carbon emissions target for new build schemes within the UK are usually defined as a percentage reduction (PR) of the regulated emissions from a chosen reference case.

$$\xi_{Target} = \xi_{Total,ref} - PR * \xi_{Reg,Ref} \tag{18}$$

The reference case consists of a benchmark building construction and an energy supply configuration chosen to represent the "business as usual" case for each building. For example, the reference case within the zero carbon homes initiative is defined as all new dwellings constructed in adherence to 2006 Part L building standards [37], heated using natural gas boilers and all electricity supplied via the grid [2]. The regulated emissions, $\xi_{Reg,Ref}$, are defined as those that result from the consumption of space heating, space cooling, domestic hot water and lighting [3].

$$\xi_{Reg,Ref} = \xi_{SH} + \xi_{SC} + \xi_{DHW} + \xi_{L} \tag{19}$$

The total emissions, $\xi_{Total,Ref}$, are defined as those that are due to the fuel consumption at the energy centre and within each building cluster, and from the electricity supplied by the grid, ξ_{Egrid}

$$\xi_{Total} = \sum_{g=1}^{Ng} \xi_G^{(g)} + \sum_{c=1}^{Nc} \xi_{NG}^{(c)} + \xi_{Egrid} \tag{20}$$

The structure for the emissions target calculation is shown by Fig. 6.

The emissions due to electricity supplied by the grid was determined using the marginal carbon emissions factor approach as recommended by the Clean Development Mechanism (CDM) Executive board of the UN Framework Convention on Climate Change Committee (UNFCCC) [38]. This method uses a reference case to define a benchmark annual consumption of grid supplied electricity. The annual emissions of this case are determined using the average carbon emissions factor of the generators that supply the grid, CEF_{Ave}. Any change of electricity consumption relative to the benchmark results in a corresponding change of emissions that is determined by the marginal dispatch carbon emissions factor, CEF_{Marg}. This corresponds to the generation plant that are expected to change their output in response to a change in demand. Several projections for CEF_{Marg} are found in literature [39–41] as illustrated by Fig. 7.

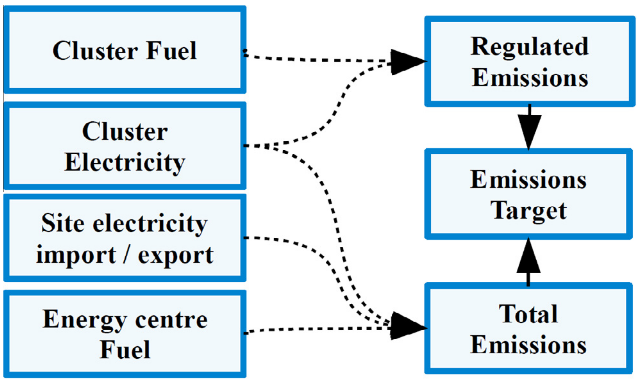

Fig. 6. Structure and data flow of emissions analysis module.

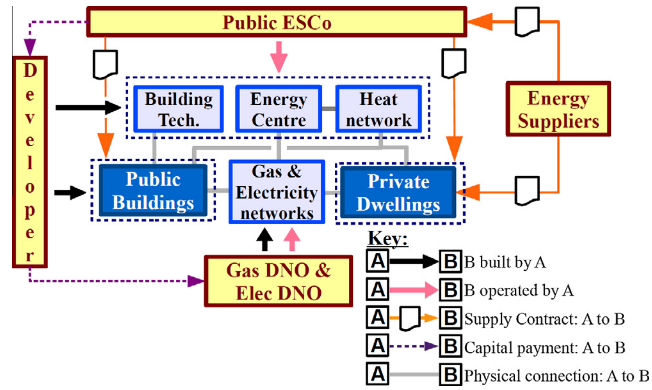

Fig. 8. Scheme layout for the works, Ebbw Vale, including main service corridors for energy distribution networks (adapted from Ref. [30]).

4. Optimisation

4.1. Optimisation formulation

The organisational and ownership structure may vary for different community energy schemes. The structure shown in Fig. 8, was adopted for the formulation of the optimisation. The capital expenditure for the energy infrastructure was incurred by the developer. It was assumed that the gas and electricity networks were built and operated by the gas and electricity distribution network operators respectively, with the total construction cost passed to the developer. No consideration was given to network operator's revenue streams such as use of system charges. A publicly owned energy services company (public ESCo) provided the operation and maintenance of the community heating scheme, the energy centre and the energy supply technologies installed within buildings owned by the local authority (public sector buildings, affordable homes and business units).

4.1.1. Objective function

The objective function was defined as the capital cost of the infrastructure to the developer, C_{Infr}. The optimisation objective is therefore stated as:

$$min \quad C_{Infr} = C_{Build} + C_{GN} + C_{EN} + C_{CES} - NPV(C_{ESCo}) \tag{21}$$

where C_{Build} is the cost of the building level technologies:

$$C_{Build} = \sum_{c=1}^{Nc} N_B^{(c)} \left(f_{GSHP}^{(c)} c_{GSHP}^{(c)} + f_{ASHP}^{(c)} c_{ASHP}^{(c)} + f_{NGB}^{(c)} c_{NGB}^{(c)} + A_{PV}^{(c)} c_{PV} + A_{SolT}^{(c)} c_{SolT} \right) \tag{22}$$

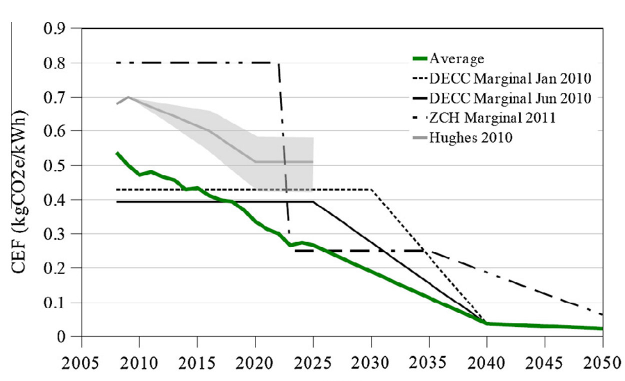

Fig. 7. Projections for the average and marginal carbon emissions factors for grid supplied electricity in the UK.

C_{GN} is the sum of all gas network edge component costs $C_{GN,e}$, and gas service connections to each building, $c_{GasServ}$:

$$C_{GN} = \sum_{e=1}^{N_{GN,e}} C_{GN,e} + \sum_{c=1}^{Nc} N_B^{(c)} c_{GasServ}^{(c)} \tag{23}$$

C_{EN} is the sum of the electricity network edge component costs, $C_{EN,e}$, the electricity service connections, c_{ElServ}, and the apportioned cost of the local 33/11 kV primary substation, $C_{PrimSub}$:

$$C_{EN} = \sum_{e=1}^{N_{EN,e}} C_{EN,e} + \sum_{c=1}^{Nc} N_B^{(c)} c_{ElServ}^{(c)} + C_{PrimSub} \tag{24}$$

and C_{CES} is the cost of the community energy scheme consisting the cost of each district heating pipe $C_{DHN,e}$, the service connection to each building c_{DHserv}, each energy centre plant, C_G, and the heat accumulator C_{HAcc}:

$$C_{CES} = \sum_{e=1}^{N_{DHN,e}} C_{DHN,e} + \sum_{c=1}^{Nc} N_B^{(c)} c_{DHNserv}^{(c)} + \sum_{g=1}^{Ng} C_G^{(g)} + C_{HAcc} \tag{25}$$

The profit generated by the publicly owned ESCo, C_{ESCo}, was considered as revenue of the local authority. The net present value of C_{ESCo} was therefore used to discount the capital cost of the infrastructure. This was defined by:

$$NPV(C_{ESCo}) = \sum_{t=1}^{N_t} \frac{C_{Inc} - C_{Exp}}{(1+DR)^t} \tag{26}$$

where C_{Inc} is the total annual income and C_{Exp} the total annual expenditure of the ESCo. A design condition was applied that assumed the annual energy bill for each local authority owned building must not exceed that of the reference case. This allowed the simplification of C_{Inc} to consist the sum of the total reference case annual energy bill and the revenue obtained from the production of electricity by the energy centre plant, C_{PlElec}:

$$C_{Inc} = \sum_{g=1}^{Ng} \left(C_{PlElec}^{(g)} \right) + \sum_{c=1}^{Nc} N_B^{(c)} \left(C_{NGbill}^{(c)} + C_{ElecBill}^{(c)} \right)_{Ref} \tag{27}$$

where C_{NGbill} is the natural gas bill and $C_{ElecBill}$ the electricity bill. The annual expenditure of the ESCo, C_{Exp}, consisted of the maintenance cost of the energy centre, C_{PlMtn}, and district heat network, C_{DHNMtn}, the cost of fuel consumed at the energy centre, C_{PlFuel}, the maintenance cost of building level technologies, C_{BldMtn}, and the gas and electricity bills of the local authority owned buildings:

$$C_{Exp} = \sum_{g=1}^{Ng} \left(C_{PlMtn}^{(g)} + C_{PltFuel}^{(g)} \right) + C_{DNHMtn} + \sum_{c=1}^{Nc} \left(C_{BldMtn}^{(c)} + C_{NGbill}^{(c)} + C_{ElecBill}^{(c)} \right) \tag{28}$$

4.1.2. Optimisation variables

The set of variables, y, changed by the optimisation solver were those used to define the on-site energy supply technologies within the infrastructure model:

$$y = \left\{ f_{GCH}^{(c)}, f_{GSHP}^{(c)}, f_{ASHP}^{(c)}, f_{DHN}^{(c)}, A_{PV}^{(c)}, A_{SolT}^{(c)}, \Phi_{G,Max}^{(g)} \right\} \forall c, \forall g \tag{29}$$

It was assumed that for each cluster all buildings were supplied using the same type of heating technology. These were therefore considered as binary integer variables so that:

$$\{f^{(c)}\} \quad \in \quad \{0, 1\} \quad \forall c \tag{30}$$

The installed capacity of solar technology and the rated heat generation capacity of each plant within the energy centre were considered as continuous variables.

4.1.3. Technical constraints

It was assumed that each building was installed with only one primary heating technology so that:

$$f_{NGB}^{(c)} + f_{GSHP}^{(c)} + f_{ASHP}^{(c)} + f_{DHN}^{(c)} = 1 \quad (\forall c) \tag{31}$$

It was also assumed that the installed area of solar panels could not exceed the available roof space of each building:

$$A_{PV}^{(c)} + A_{SolT}^{(c)} \leqslant A_{Roof}^{(c)} \quad (\forall c) \tag{32}$$

The network design constraints are incorporated within the design modules described by Section 4, and were therefore not required to be explicitly defined for the optimisation solver.

4.1.4. Financial constraints

It was assumed that the ESCo was required to break even on an annual basis as a minimum condition of financial viability. This was imposed by applying the constraint:

$$C_{Inc} - C_{Exp} \geqslant 0 \tag{33}$$

4.1.5. Emissions constraint

The 60% target reduction of regulated emissions was imposed using the following emissions constraint:

$$\xi_{Total} \leqslant \xi_{Total,Ref} - 0.6\xi_{Reg,Ref} \tag{34}$$

4.2. Optimisation solver

The design tool uses a Social Cognitive Optimisation (SCO) solver developed by Xie [42]. This algorithm applies a type of evolutionary optimisation strategy whereby autonomous agents use and update a library of best points from within the solution space. By defining a set of optimisation variables from the infrastructure model design parameters, the solver was used to determine the set of values that return the minimum value of the objective function. The Social Cognitive Optimization solver was chosen due to its availability as a ready to use open source Java program. Other evolutionary optimisation strategies such as differential evolution, particle swarm optimisation and ant colony optimisation are equally applicable to the design tool.

5. Ebbw Vale case study

A new build community redevelopment scheme in South Wales was considered. "the works" [43,45] is a joint venture between the Welsh Assembly Government and Blaenau Gwent Council who shall be referred to herein as "the developer". The scheme is new build development consisting a mix of business units, schools, leisure facilities and a local general hospital. 720 domestic properties are also scheduled for construction, 20% of which are classed as "affordable homes", which are local council owned social housing for low income families (see Ref. [44]). A detailed breakdown of the building clusters within the scheme is provided by Table 3, with the site layout illustrated by Fig. 9.

The works is considered a flagship project for sustainable development in Wales. The energy strategy for the scheme sets a 60% target reduction of regulated emissions relative to a benchmark defined as all buildings built to 2006 Part L standards and supplied using natural gas boilers and grid supplied electricity [44]. The strategy requires a minimum build standard for domestic dwellings equivalent to the code for sustainable homes (CSHs) level 5, for which the annual space heating demand is reduced to 15 kW h_{th}/m^2/year [46]. For the purpose of this paper, the 2006 Part L standard [37] was assumed to apply throughout the analysis for all non-domestic premises.

The emissions and financial performance was evaluated assuming a 20 year analysis period. For the purpose of this study, it was assumed that all buildings and infrastructure was fully constructed and commissioned at the start of the first year with 100% occupancy at all buildings. The organisational and ownership structure assumed for the scheme has been discussed in Section 4 (Fig. 9).

5.1. Design cases

The design cases examined for the Ebbw Vale case study are described in Table 4. More detail can be found in Section 6.

Table 3
Detail of building clusters used to model the works redevelopment scheme, South Wales.

Cluster ID	Consumer	No. of buildings	Occupancy type	Occupied floor space (m^2/building)	Cluster area (m^2)
1	General offices	1	Office	3940	5000
2	Learning centre	1	Education	13,000	8000
3	Arts centre	1	Education	5200	10,400
4	School (11–16)	1	Education	9500	19,000
5	Leisure centre	1	Leisure centre	9500	9500
6	Residential 1	245	Residential	77.6	110,250
7	Residential 2	255	Residential	77.6	114,750
8	Business park 1	10	Office	450	12,225
9	Business park 2	30	Office	450	68,270
10	General hospital	1	Hospital	10,695	53,475
11	Business park 3	30	Office	450	42,069
12	School (3–11)	1	Education	7400	32,718
13	Residential 3	160	Residential	77.6	72,000
14	Business park 4	15	Office	450	31,912
15	Residential 4	60	Residential	77.6	27,000

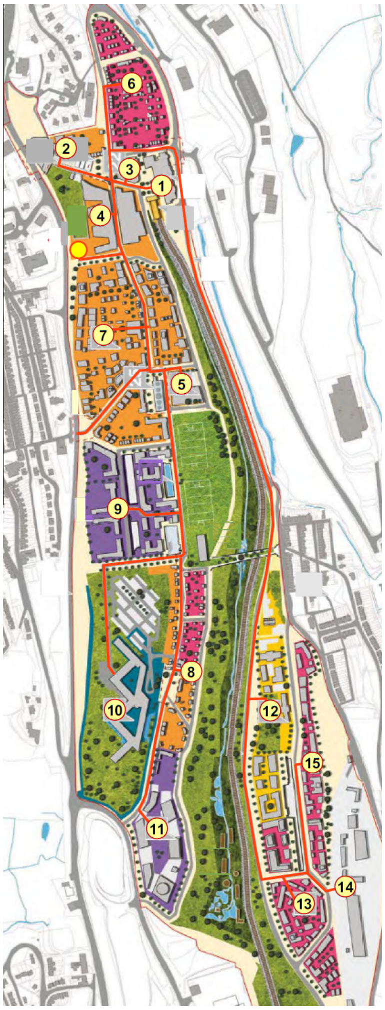

Fig. 9. Simplified organisational structure used within the financial model for the Ebbw Vale case study.

6. Results and discussion

The design tool was used to evaluate a reference case for the scheme with natural gas boilers at all premises, and with no installed capacity of photovoltaic or solar thermal panels. The resulting infrastructure is shown by Fig. 10. This provided the benchmarks for development build cost (£5.210 m), and the total annual energy bill for local authority owned buildings (£1.384 m). Fig. 11 shows the annual total emissions, regulated emissions and emissions target of the reference scheme, each of which drop over time due to the decarbonisation of electricity supplied by the grid. The accumulative emissions target of the reference case over a 20 year period starting 2012 was 81,256 tCO_2e.

Table 4
Design cases defined for the works, Ebbw Vale community development.

Design case	Build completion	CEF_{Ave}	CEF_{Marg}
Reference	–	DECC 2010	–
Case A	2012	DECC 2010	DECC 2010 (June)
Case B	2020	DECC 2010	DECC 2010 (June)
Case C	2012	DECC 2010	ZCH 2011

The design tool was applied to determine the optimal cost carbon constrained infrastructure design assuming a 20 year analysis period starting from 2012 (Design case A). The DECC June 2010 projection for CEF_{Marg} was used to evaluate the emissions corresponding to any change of electricity supply from the grid. The result is shown by Fig. 12 and consists of a district heat network supply to all public buildings and business units. This was supplied by a 2.4 MW_{el} natural gas CHP plant with a 170 m^3 heat accumulator. The heat demand at all residential dwellings was met using a mix of ground source and air source heat pumps. A total of 10,016 m^2 (1.5 MW_{el}) of PV and 5490 m^2 (2.47 MW_{th}) of solar heating was required for the scheme. The structure of the electricity network was unchanged from the reference case and therefore omitted for clarity. Table 5 provides a summary of the key results.

The total cost to the developer was £23.235 m, so that the cost of achieving the emissions reduction target was £18.025 m. This consisted of the cost of technologies installed at each building, including £7.2 m for the cost of PV and £6.3 m spent to meet the CSH level 5 standard for domestic dwellings as discussed in Section 5. The discounted cost of the infrastructure owned by the ESCo was £2.15 m, assuming a UK social discount rate of 3.5%. The technology mix and the corresponding cost are expected to be sensitive to the discount rate. A discount rate of 3.5% was chosen for the Ebbw Vale development as it is an area of social deprivation.

A breakdown of the reduction of the annual emissions for case A relative to the reference case is shown by Fig. 13. The contribution the total emissions reduction by each technology used is best understood by considering the change of energy use relative to the reference case. An improvement of the building fabric and the installation of solar thermal heaters both reduce the natural gas consumed for the provision space heating and hot water. The corresponding emissions reduction is therefore constant over time if the fuel emissions intensity is assumed to be constant. The installation of PV results in a change of the amount of electricity annually imported from the grid. The resultant change of emissions is in this case determined using CEF_{Marg}, which when

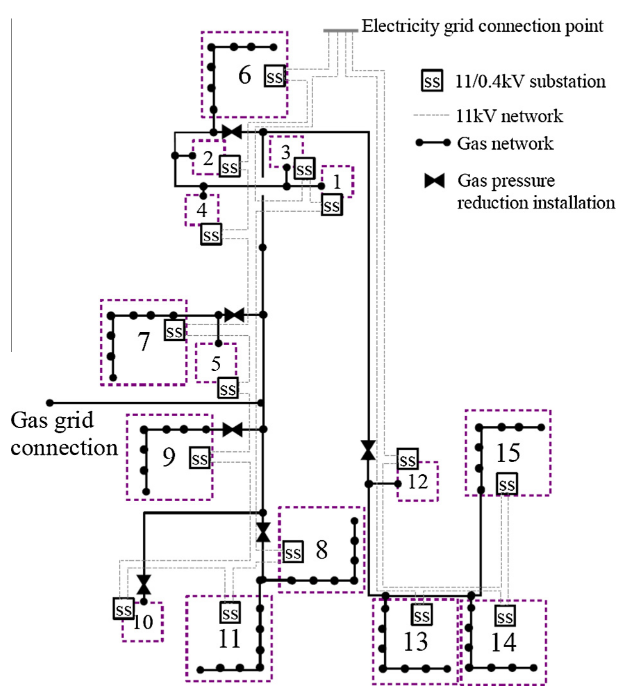

Fig. 10. Reference case infrastructure.

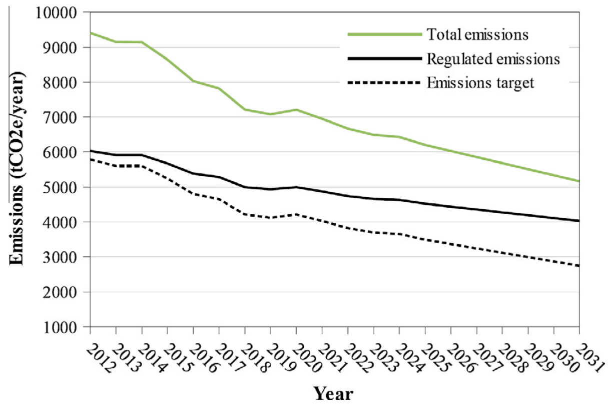

Fig. 11. Variation of [1] the reference total, reference regulated and annual emissions target of the Ebbw Vale scheme.

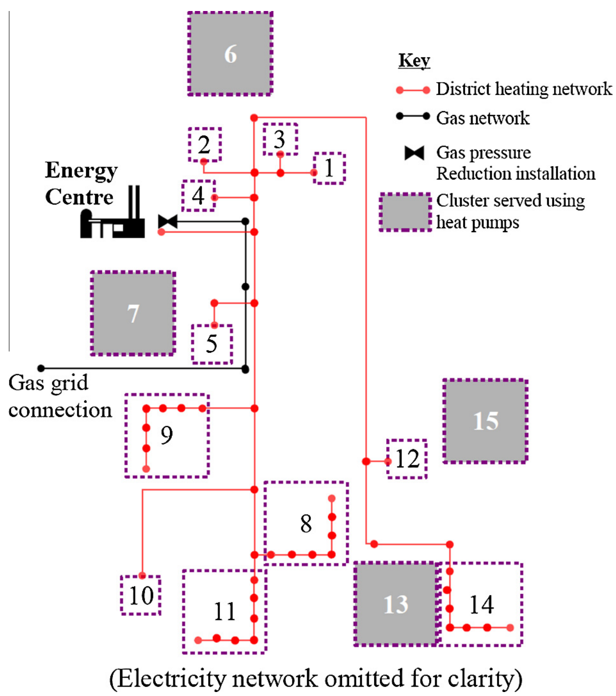

Fig. 12. Optimal infrastructure design for design case A (DECC 2010 marginal emissions projection).

applying the DECC projection of June 2010 has a constant value until 2025 from which point it decreases linearly. This characteristic is therefore also displayed in the plot of emissions reduction over time.

The emissions reduction achieved by using district heating with Natural gas CHP, and by using heat pumps, is the result of a combination of these two mechanisms. The use of natural gas CHP to supply heat instead of gas boilers results in an increase of the annual natural gas consumption, but also a decrease of the amount of electricity supplied to the scheme from the grid. The net result is a constant reduction of annual emissions until 2025 from which point it shows the linear decrease characteristic resulting from the CEF_{Marg} projection. Beyond 2031, the emissions from the additional natural gas consumption exceeds the savings obtained from reducing grid supplied electricity and thus natural gas CHP becomes a net contributor to total annual emissions relative to

Table 5
Summary of results of the optimal solution for design case A (analysis start date = 2012; CEF_{Marg} = DECC 2010 (June)).

ID	Heating type	PV capacity (m^2/building)	Solar hot water (m^2/building)
Cluster			
1	District heating	155	94
2	District heating	155	345
3	District heating	69	345
4	District heating	576	306
5	District heating	522	286
6	Heat pumps	7.8	2.8
7	Heat pumps	7.8	2.8
8	District heating	18	4
9	District heating	26	17
10	District heating	193	422
11	District heating	24	18
12	District heating	226	440
13	Heat pumps	4.1	2.8
14	District heating	113	1.2
15	Heat pumps	2.6	5.1
Energy centre			
Plant 1: Natural gas CHP (ICE). 3700 KW_{th}/2400 kW_{el}			
Plant 2: Natural gas boiler. 8700 KW_{th}			
Heat accumulator: 170 m^3			
Costs			
Electricity network:	£2.448 m	DHN capex	£3.761 m
Gas network:	£0.039 m	DHN opex	£0.230 m/year
Building technologies:	£18.589 m	Electricity revenue	£0.283 m/year
ESCo scheme:	£2.159 m	Net revenue from consumers	£0.436 m/year
		Fuel expenditure:	£0.377 m/year
		Net revenue	£0.113 m/year
Total	£23.235 m	NPV (3.5% discount rate)	−£2.159 m

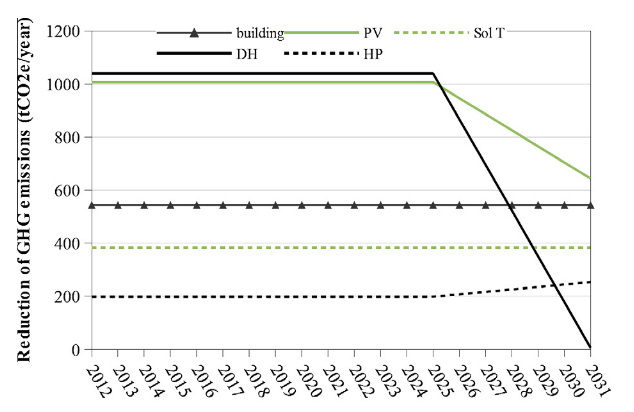

Fig. 13. Contribution of emissions from each on site technology for the optimal solution of design case A.

the reference case. The use of heat pumps on the other hand results in a reduction of annual natural gas consumption compared to natural gas boilers, but increase the amount of electricity supplied from the grid. Thus, the reduction of annual emissions by using heat pumps increases as CEF_{Marg} decreases from 2025.

An additional consequence of the opposing mechanisms of emissions reduction for different supply technologies is the sensitivity of the optimal solution to the starting year of the analysis period. This was examined using the design tool by changing the start of the 20 year analysis period to 2020 (design case B). The results are summarised by Table 6. The optimal solution now consists of gas boilers at cluster 4 (the school), residential clusters 6 and 13, and at the business park cluster 14. All remaining clusters were supplied using heat pumps. A total of 372 kW_{el} PV and 4.03 MW_{th} of solar hot water panels were required for the scheme. None of the clusters were supplied using a district heat network. The total cost of the optimal energy infrastructure was £20.151 m, which was comprised of £1.797 m for PV, £1.792 m for solar hot water and £7.336 m for heat pumps. The total cost of introducing the carbon emissions constraint was therefore £14.941 m.

Fig. 14 provides a comparison of the variation of annual on-site emissions over time for the optimal solutions of case A and case B. It is observed that the emissions performance results from the emissions constraint being applied as an accumulation of the 20 year period as a whole rather than to each year individually. The case A optimal solution initially achieves a significant reduction of annual emissions until the assumed linear reduction CEF_{Marg} begins in 2025. From this point the total on-site emissions reduction due to the avoided import of grid electricity decreases by the mechanism previously described. This is observed as the sudden change from a constant reduction of emissions (with the emissions projections for the reference case and case A being parallel) in 2025. Case B, which primarily consists of heat pumps and PV, initially delivers a lower the on-site target emissions reduction than case A until 2028 from which point the case B delivers the highest reduction. Both heat pumps and PV are effected by a decrease of CEF_{Marg}, but with the annual emissions reduction increasing for heat pumps and decreasing for PV. These opposing mechanisms cancel out so that the sudden change observed in case A is not as prevalent for case B.

The optimal solutions so far described were obtained on the basis that the DECC June 2010 projection of CEF_{Marg} applied to the design of the scheme. However, as described within Section 3.11, several alternative projections have been proposed. The impact of the choice of CEF_{Marg} upon the optimal infrastructure design was examined using design case C. The results are summarised by Table 7. The scheme now consists of a much smaller district heating scheme to supply the highest load density buildings including the leisure centre and hospital, with natural gas boilers at all remaining premises. The minimum additional cost of meeting the emissions target is £7.658 m, which is a 57.5% decrease relative to the use of the DECC June 2010 projection.

A comparison of the optimal results is provided by Fig. 15. This highlights the significant change to the cost and composition of the energy supply infrastructure when applying a carbon constrained approach to design. A significant proportion of the costs result from the installation of PV, solar thermal panels or heat pumps. A significant contribution to overall costs is also incurred from meeting the domestic CSH level 5 building standard. Each optimal design specifies a mix of PV, solar thermal and a primary heating technology at each premise. In case A (Fig. 15), the annual revenues raised by the ESCo are insufficient to recover the total upfront capital costs. The shortfall of the revenue over the capital cost is accounted for as an unrecoverable cost in the model and thereby holds the financial constraint imposed. In cases B and C, however, the capital costs are recovered within the 20 year project period resulting in a net overall profit. Since the scheme is publicly funded and owned, the total profit is accounted for as a reduction of the required up front capital cost.

The formulation of the model applies several assumptions that can be adjusted where the required detail differs compared to the

Table 6
Summary of results for design case B.

ID	Heating type	PV capacity (m^2/building)	Solar hot water (m^2/building)
Cluster			
1	Heat pumps	72	96
2	Heat pumps	62	562
3	Heat pumps	24	359
4	Gas boilers	98	532
5	Heat pumps	25	809
6	Gas boilers	0.3	4.3
7	Heat pumps	0.3	4.3
8	Heat pumps	8.3	14
9	Heat pumps	4	30
10	Heat pumps	2	510
11	Heat pumps	17	40
12	Heat pumps	4	247
13	Gas boilers	0.3	5.2
14	Gas boilers	88	21.7
15	Heat pumps	0.2	4.3
Energy centre			
None			
Costs			
Electricity network:	£2.624 m	DHN capex	N/A
Gas network:	£0.372 m	DHN opex	N/A
Building technologies:	£18.569 m	Electricity revenue	N/A
ESCo scheme:	−£1.416 m	Net revenue from consumers	£0.099 m/year
		Fuel expenditure:	N/A
		Net revenue	£0.099 m/year
<u>Total</u>	<u>£20.151 m</u>	NPV (3.5% discount rate)	£1.416 m

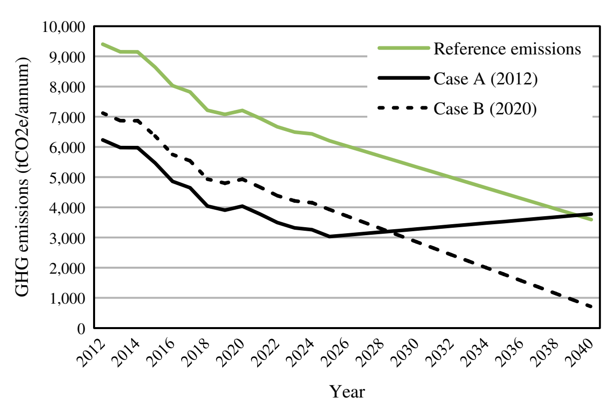

Fig. 14. Comparison of annual emissions of design case A and design case B.

Table 7
Summary of results for design case C (project start date = 2012; CEF_{Marg} = ZCH marginal emissions projection).

ID	Heating type	PV capacity (m^2/building)	Solar hot water (m^2/building)
Cluster			
1	Natural gas boilers	121	390
2	Natural gas boilers	113	821
3	Natural gas boilers	186	413
4	Natural gas boilers	11	642
5	District heating	164	395
6	Natural gas boilers	0.1	4.2
7	Natural gas boilers	0.1	4.2
8	District heating	18	39.0
9	Natural gas boilers	0	107
10	District heating	220	468
11	Natural gas boilers	4	110
12	Natural gas boilers	175	572
13	Natural gas boilers	0.2	4.0
14	Natural gas boilers	16.8	94
15	Natural gas boilers	0.2	9.1
Energy centre			
Plant 1: Natural gas CHP (ICE). 1100 KW_{th}/635 kW_{el}			
Plant 2: Natural gas boiler. 3325 kW_{th}			
Heat accumulator: 80 m^3			
Costs			
Electricity network:	£2.208 m	DHN capex	£1.287 m
Gas network:	£0.709 m	DHN opex	£0.081 m/year
Building technologies:	£12.809 m	Electricity revenue	£0.113 m/year
ESCo scheme:	−£2.868 m	Net revenue from consumers	£0.424 m/year
		Fuel expenditure	£0.163 m/year
		Net revenue	£0.292 m/year
Total	£12.868 m	NPV (3.5% discount rate)	£2.868 m

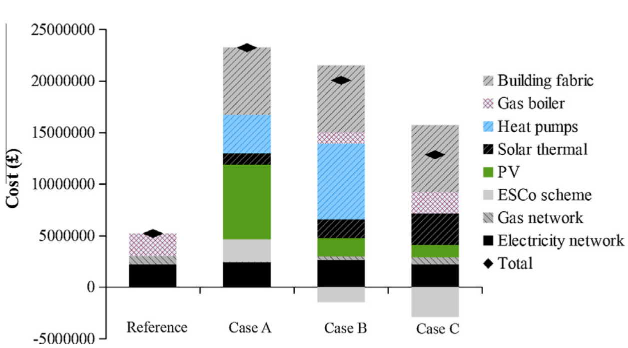

Fig. 15. Comparison and breakdown of the total cost of each design case considered for the Ebbw Vale case study.

presented case study. The building fabrication was modelled by using end use consumption values expected at the standards specified at each case. Variables to represent the building fabric can be introduced in future work in order to allow an examination of the interaction between building design and energy infrastructure. It was assumed in the model that for each cluster all buildings were supplied using the same type of heating technology. A cluster can be defined based on smaller segments, e.g. each building, for the model to consider using various types of heating technologies for different buildings. A constraint was applied by assuming that the ESCo scheme was required to break even on an annual basis as a minimum condition of financial viability. This can be changed to require a specified annual rate of return as a minimum.

7. Conclusions

The carbon constrained design of energy infrastructure for new building schemes requires consideration of the interactions between the technical performance, carbon emissions and financial performance of the available supply technologies. An integrated model was developed to combine the various aspects of system performance within a single optimised design tool. This was applied to investigate the carbon constrained design of a new build energy supply infrastructure in South Wales, UK.

The requirement to deliver a reduction of greenhouse gas emissions using on site technologies has a significant impact upon the infrastructure design and cost. For the investigated case study, a 60% reduction of regulated emissions was achieved by using a mix of PV, solar thermal, heat pumps and a district heating network supplied using a natural gas combined heat and power unit. Each of these technologies is capital intensive and results in an increased investment of £18.023 m above the reference case with no on-site carbon constraint. This is a significant increase of costs for a relatively small community scheme consisting of 750 dwellings and public amenities, and may provide a significant obstacle against access to investment capital.

The optimal carbon constrained design of the scheme was shown to change significantly with the year of build completion. This results from the interdependency between the reduction of on-site emissions achieved using technologies such as PV, CHP and heat pumps and the emissions intensity of electricity supplied from the grid. Technologies such as PV and CHP-DH deliver emissions savings via the displacement of grid supplied electricity and are deployed extensively within the scheme built at 2012 when the marginal emissions factor is relatively high. Heat pumps on the other hand, deliver emissions savings by displacing the consumption of natural gas for heating with grid supplied electricity and are the predominant technology deployed within the scheme when built at 2020. This would suggest that NG-CHP is unsuitable as a long term option for new community schemes, with heat pumps providing a more cost effective option to developers in the long term. As a major component of the optimal solution in the near term however, NG-CHP may provide a means of developing heat networks to allow the future use of emerging technologies such as large scale heat pumps, biomass gasification, anaerobic digestion and energy from waste.

The optimal design and cost were shown to be sensitive to the projection used to estimate the marginal carbon emissions factor of grid supplied electricity. A cost decrease of £11.367 m was obtained by a change from the DECC June 2010 projection of marginal grid supplied electricity emissions to that proposed by the Zero Carbon Hub in 2011. This resulted in a significantly reduced capacity of PV installed within the scheme and extent of the district heat network required on site. Several potential issues that may arise from the current lack of consensus upon the choice of projection include an over estimate of the real emissions savings obtained for a scheme, a significant capital overspend if the use of high capital low carbon technologies such as PV is over prescribed, and the possibility of developers cherry picking a projection that favours the use of a particular technology. This highlights the necessity for establishing a consistent approach for estimating a projection of the marginal emissions factor for grid supplied electricity.

Acknowledgements

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Appendix A.

See Tables A1–A3.

Table A1
Equipment inventory.

	Rating (A)	R (Ω/km)	X (Ω/km)	Cost [34] (£/m)
0.4 kV cable [47]				
95 mm^2 wavecon	201	0.32	0.075	50*
185 mm^2 wavecon	292	0.164	0.074	55*
300 mm^2 wavecon	382	0.1	0.073	60*
11 kV cable [47]				
95 mm^2 XLPE	233	0.32	0.119	50*
185 mm^2 XLPE	337	0.164	0.108	55*
300 mm^2 XLPE	442	0.1	0.101	60*
	Type	R^{21} (Ω)	X^{21} (Ω)	Cost [34] (£)
Electricity transformers				
7500	33/11 kV	–	–	383,160*
15,000	33/11 kV	–	–	494,760*
315	11/0.4 kV	0.009	0.0268	26,748*
500	11/0.4 kV	0.0051	0.0171	27,404*
800	11/0.4 kV	0.0029	0.0107	29,140*
1000	11/0.4 kV	0.0022	0.0086	30,504*
	Roughness		Installed cost [35] (£/m)	
Gas pipes [48]				
32 mm PE	0.08		5.8	
63 mm PE	0.08		7.3	
90 mm PE	0.08		13.6	
125 mm PE	0.08		26.2	
180 mmPE	0.08		62.2	
250 mmPE	0.08		100.6	
315 mmPE	0.08		138.6	
375 mmPE	0.08		173.9	
Gas network components		Cost		
Grid connection		£4,470/connection		
PRI		£7,500/unit		
Domestic service connection		£590/dwelling		
Commercial service connection		£1800/connection		
District heat pipes [49,50]:	Roughness	Insulation	Insulation thermal conductivity [36] (W/m/K)	Installed cost [36] (£/m)
32 mm Steel	0.08	PU (0.1 m)	0.028	134*
40 mm Steel	0.08	PU (0.1 m)	0.028	140*
50 mm Steel	0.08	PU (0.1 m)	0.028	146*
65 mm Steel	0.08	PU (0.1 m)	0.028	151*
80 mm Steel	0.08	PU (0.1 m)	0.028	161*
100 mm Steel	0.08	PU (0.1 m)	0.028	182*
125 mm Steel	0.08	PU (0.1 m)	0.028	209*
150 mm Steel	0.08	PU (0.1 m)	0.028	259*
200 mm Steel	0.08	PU (0.1 m)	0.028	325*
250 mm Steel	0.08	PU (0.1 m)	0.028	488*
Building level technologies [53]:			Cost	
Gas boilers (domestic) [37]			£2,500/dwelling	
Gas boilers (commercial) [37]			£45/kW_{th}	
Ground source heat pumps (domestic) [38,51]			$2{,}560(\Phi_{SH,max})^{0.8}$ (£/dwelling)	
Ground source heat pumps (commercial) [37]			£1000/kW_{th}	
Air source heat pumps (domestic) [37]			£600/kW_{th}	
Air source heat pumps (commercial) [37]			£600/kW_{th}	
District heat network connection (domestic) [37,54]			£4820/dwelling	
District heat network connection (commercial) [37,54]			£20/kW_{th}	
Photovoltaic panels [39,52]			£725/m^2	
Solar thermal hot water panels [41]			$400\,A_{SolT} + 400$ (£/installation)	
Energy centre plant			Cost (£)	
Large scale natural gas boiler [41]			$7171(\Phi_{Max}/1000)^{0.93} + 3365$	
Natural gas internal combustion engine CHP [37,42,55]			$1712\,P_{max}{}^{-0.11}$	

* Original source adjusted for inflation.

Table A2
Energy price assumptions.

Utility	Price
Electricity (domestic retail) [43,56]	13.72 p/kW h
Electricity (non-domestic retail, 0–20 MWh/year) [44,57,58]	12.12 p/kW h
Electricity (non-domestic retail, 20–499 MWh/year) [44,57,58]	10.22 p/kW h
Electricity (non-domestic retail, 500–1999 MWh/year) [44,57,58]	8.79 p/kW h
Electricity (non-domestic retail, >2000 MWh/year) [44,57,58]	7.91 p/kW h
Electricity (wholesale) [45,58]	5 p/kW h
Electricity (export)	4 p/kW h (80% of wholesale)
Electricity (climate change levy) [46,57]	0.485 p/kW h
Gas (domestic retail) [47]	3.40 p/kW h + £106.63/dwelling
Gas (non-domestic, <278 MWh/annum) [44,60]	3.31 p/kW h
Gas (non-domestic, <2778 MWh/annum) [44]	2.47 p/kW h
Gas (non-domestic, <2778 MWh/annum) [44]	2.14 p/kW h
Gas (climate change levy) [46,59]	0.169 p/kW h
District heating (to private consumers)	(same as gas price)

Table A3
Typical annual energy consumption for buildings based on 2006 part L building standards.

Occupancy type	Space heating (kW h/m^2)	Hot water (kW h/m^2)	Appliance and lighting			Space cooling (kW h/m^2)
			Auxilliary (kW h/m^2)	Lighting (kW h/m^2)	Equipt (kW h/m^2)	
Office [3]	103.9	15.5	9.3	46.5	60.5	13.9
Education [3]	51.5	30.9	4.7	34.9	34.9	0
Health [3]	87.6	46.4	27.9	62.8	144.2	0
Retail [3]	56.7	0	18.6	158.2	30.2	113.9
Leisure [3]	0	159.8	34.9	51.2	32.6	69.8
*Residential [48]	65.1	25.0	0	8.8	31.7	0

* Assumes a mix of 25% detached houses, 27% terraced houses, 21% semidetached and 27% apartments.

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