Programme Area: Energy Storage and Distribution

Project: 2050 EIO Multi Vector Integration Analysis

Title: Multi Vector Interaction Cases Shortlist

Context:

The project aims to improve the understanding of the opportunity for and implications of moving to more integrated multi vector energy networks in the future. Future energy systems could use infrastructure very differently to how they are employed today. Several individual energy vectors - electricity, gas and hydrogen - are capable of delivering multiple services and there are other services that can be met or delivered by more than one vector or network.

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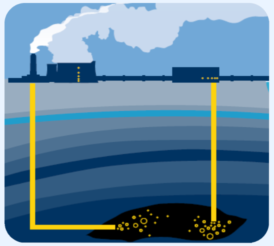

Multi-vector integration project

D2.1 – Report on multi-vector case definitions

12th August 2016

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Introduction

Introduction

- This document is submitted as Deliverable 2.1 under the ETI’s Multi-vector Integration Project
- The material is adapted from the presentation provided to the project steering group at the WP2 Case Study definitions workshop held in London on August 2nd 2016
- The main objectives of this workshop were to:
  - > For each case, agree the system configurations of multi-vector (MV) and single-vector (SV) instances
  - > Discuss the degrees of freedom available in each case that can be used to 'optimise' the MV and SV configurations
  - > Agree the expected outputs from the modelling that will be used to calculate the multi-vector case benefit
  - > Discuss the inputs required for each case and for the 'global scenarios' and the data sources to be used
  - > Agree the exogenous parameters of interest for each MV solution model

Structure of this document

- This document is structured as follows
  - > Model structure
    - > Common features used to define each case
    - > Global parameters used to describe a particular ‘future world’
  - > Case study definitions – detailed modelling proposals for each case study
    - > Setting and model boundary
    - > MV and SV configurations and degrees of freedom available to optimise
    - > Inputs and data sources
    - > Outputs required for the assessment of multi-vector benefit
  - > Project programme and next steps

Proposed Shortlist of multi-vector interaction case studies

Short-list of cases

1. Domestic scale heat pumps and peak gas boilers.
2. Gas CHP and Heat Pumps supplying district heating and individual building heating loads.
3. PHEV switching fuel demand from electricity to petrol or diesel.
4. RES to H_2/RES to CH_4
5. RES to DH and Distributed Smart Heating (“virtual” DH networks)
6. Anaerobic Digestion/Gasification to CHP or grid injection

The short-listed cases, above, were agreed during a teleconference with the steering group on July 4th 2016. The process of filtering from the initial long-list to identify this short-list was discussed at the Alignment workshop held on June 24th. Details of the long-list and the criteria used to filter and prioritise cases can be found in deliverable **D1.1 – Report on multi-vector interactions and priority interactions short-list**.

Modelling Structure – A number of features have been defined that are used to describe each case study

In order to specify the model cases, the following parameters must be defined

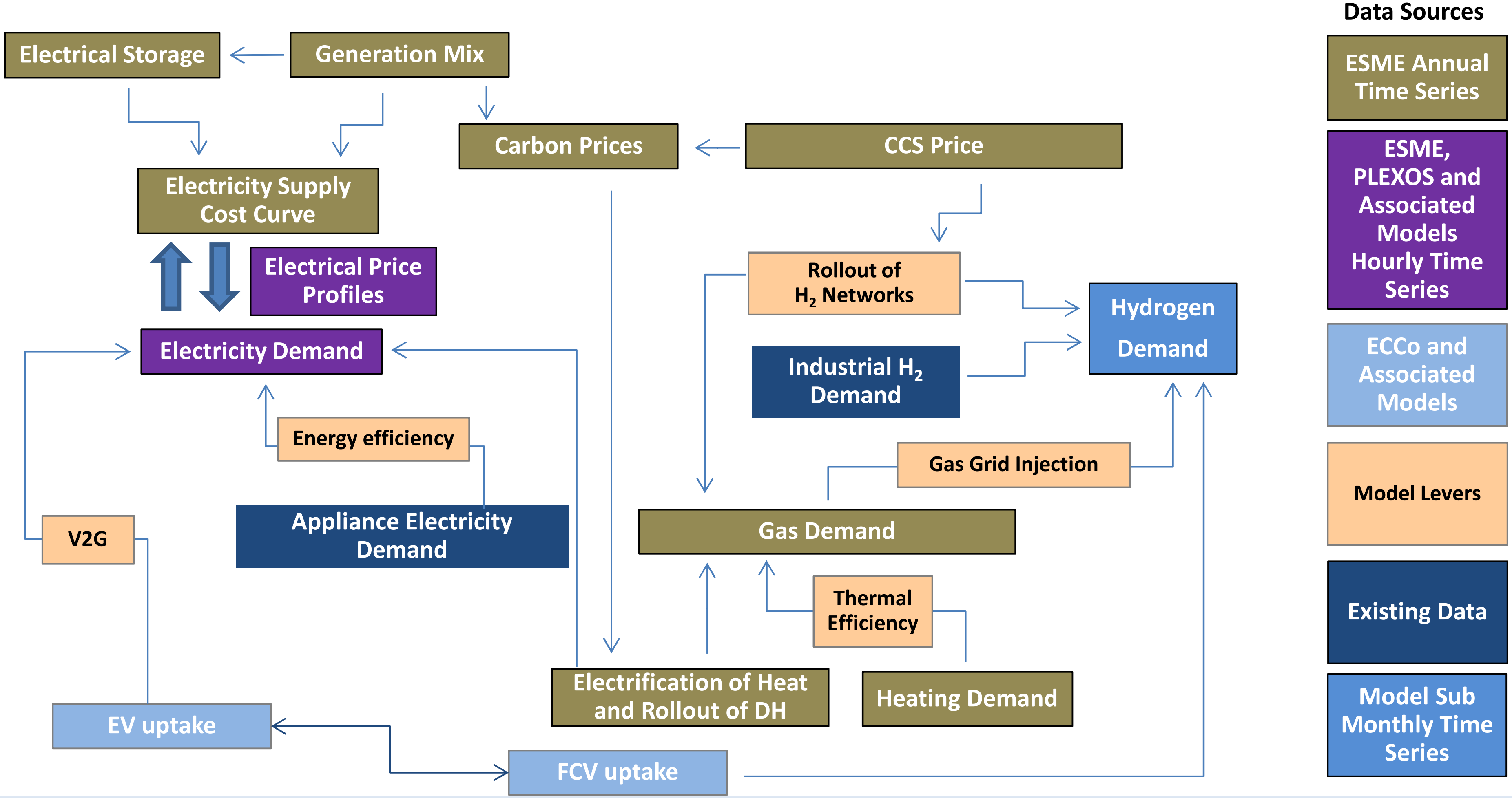
Model	Description	Examples
1. Global and System Data	System level data, defined consistently across all case studies. Some will be exogenous, some endogenous, to each case study.	• Generation Mix • Carbon Prices • EV Uptake • Electrification of Heat • CCS Prices
2. Setting	The system levels and /or geographic location that are considered in the model, in which the particular MV interaction may provide significant value.	• Secondary transformer circuit • Archetypal UK town • An area of constrained grid (e.g. an island)
3. Model Boundary	The model boundary defines the variables and sub-systems that are optimised over. Further features of the energy system that are outside the model boundary, e.g. supply and demand characteristics, infrastructure availability etc., may be relevant to the case study but do not react dynamically its optimisation.	• Electrical generation fleet and total system demand • District heating scheme, local renewable generation and associated electrical network
4. Exogenous Variables of Interest	For a given Case Study, the effect on the MV value of particular variables exogenous to the model may also be investigated, in order to determine the scenarios under which the MV solution is particularly powerful, or marginal.	• EV uptake (in a heat pump scenario) • Electrical wholesale price volatility (in a local scenario)

Global Parameters – A range of parameters are defined that describe a particular future energy system scenario

Global Parameter	Source	Case Study Effects	Downscaling and Local Implementation
Electrical Generation Mix	ESME model	• Supply and marginal production costs • Prices profiles and volatility • Carbon prices	
EV Uptake and Dynamic Charging Profiles	ECCO model	• Endogenous or exogenous increased electrical demand • DSM Potential	
Electrification of On-Site Space and Water Heating	HP uptake from ESME model	• Electrical demand profiles and associated price effects	
Electrical price time series	Short run marginal costs and/or LCOE from ESME and PLEXOS models	• Margins for projects involving price response and/or balancing	Consider in some cases additional price volatility based on empirical assessments of e.g. Energiewende.
Electrical Storage Deployment	ESME model	• SV counterfactual costs around peak electrical demand and/or oversupply.	ESME does not locate storage at a particular system level. For particular case studies, the costs may be used to inform local SV counterfactuals.
District Heat Rollout	EE study on Pathways to high heat pump penetration (CCC)	• Little exogenous effect on the case studies, but will affect scalability of some MV solutions	
Hydrogen Networks deployment	City Gate project vision scenarios	• Regional level H_2 demand	Will be considered for demand matching in the P2G scenario.
CCS Prices	ESME model	• Viability of H_2 networks • Carbon Prices	

Global Parameters – The relationships between global parameters and 'local' parameters used in the case models

The global system is determined by a consistent set of projections. The interdependencies of these global parameters with key local case study features is shown in the schematic below. A set of global scenarios will be constructed from these parameters, describing different outcomes for the future energy system. These scenarios provide a framework for assessing the impact of the global parameters on the multi-vector value in particular local cases.



Setting and Boundary

Setting(s)

- In order to quantitatively assess each MV scenario, a Case Study boundary, and in particular the location within the energy system must be specified; the multi-vector solution costs and benefits will be assessed within this boundary.
- Parameters within the boundary react dynamically to the system state; while those outside may contribute to the overall costs but are exogenous. Therefore parameters outside the model effectively have flat marginal cost curves - so, for example, peak electrical prices do not rise or fall as demand is moved off or onto the electrical network.
- Some Case Studies will be presented in more than one setting to elucidate MV value across various potential modes or levels of implementation.
- Case studies boundaries are selected so as to best capture upstream costs; such externalities as there are will be qualitatively assessed.

Case Study Optimisation 1

Timeframe

- For each Case Study, the associated model is run over a single year on an hourly resolution; all capex is annualised over that timescale, and all outputs are reported on this basis.
- In some Case Studies, the MV solution value may differ significantly in typical year and extrema of, for example, low wind speed, cold winters, etc. In such instances, a range of relevant cases will be investigated.
- Parameters whose future behaviour is of interest, such as generation mix and carbon price, will be varied to quantify the changing value of MV solutions out to 2050.

Single Vector and Multi Vector System “Optimisation” Degrees of Freedom

- For a given Case Study energy demand profile or set of profiles the model will attempt to minimise system costs using
  - a class of single-vector, and
  - both single vector and a further class of multi-vector options.
- The models find the optimal balance of these costs in each case; the difference between the SV and MV total system spend then determines the MV value for a particular Case Study (for a given choice of exogenous parameters).

Case Study Optimisation 2

Model Reporting

An example of the optimised SV and LV configuration system costs are shown below, for a particular choice of the parameters exogenous to the case study.

Total Expenditure	Optimum SV Configuration	Optimum MV Configuration
Grid Network Reinforcement Cost (£m)	40	20
MVP Alternative Network Opex/Repex (£m)	10	20
Electricity Costs (£m)	25	15
Gas Costs (£m)	5	10
Annualised MV Infrastructure Capex (£m)	0	4
Annualised System Capex (£m)	3	5
Carbon Emissions (ktonnes)	*1.2*	*1.4*
Carbon Price (2035)	3	5
Total (£m)	86	79

Outputs

Cost Benefit Analysis and Reporting

In order to determine the case study value of the MV solution, the model will optimise the SV, and then the MV system configurations based on the following:

- the **network costs** associated with reinforcement, opex and decommissioning value
- **fuel costs** and the associated **emissions pricing** and
- additional **generation** and other **technology capex and opex**
- **revenues from sales** (e.g. electricity, renewable gas), where applicable
- **Engineering** or **business model** barriers and the associated cost of system transformation as will be assessed in WP3.

Note that in many cases, many costs may be unchanged in the SV and MV cases, and can therefore by netted out.

In each Case Study, an indication of who bears particular costs will be indicated. Where costs are or can be socialised, and where the system benefits may not be equally distributed, this will also be noted.

Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

Case Description

For a future in which heat is highly electrified, this case study considers under what conditions the costs of maintaining gas boilers and networks are recouped by the savings in electrical grid reinforcement associated with peak heating demand. Three scenarios are considered:

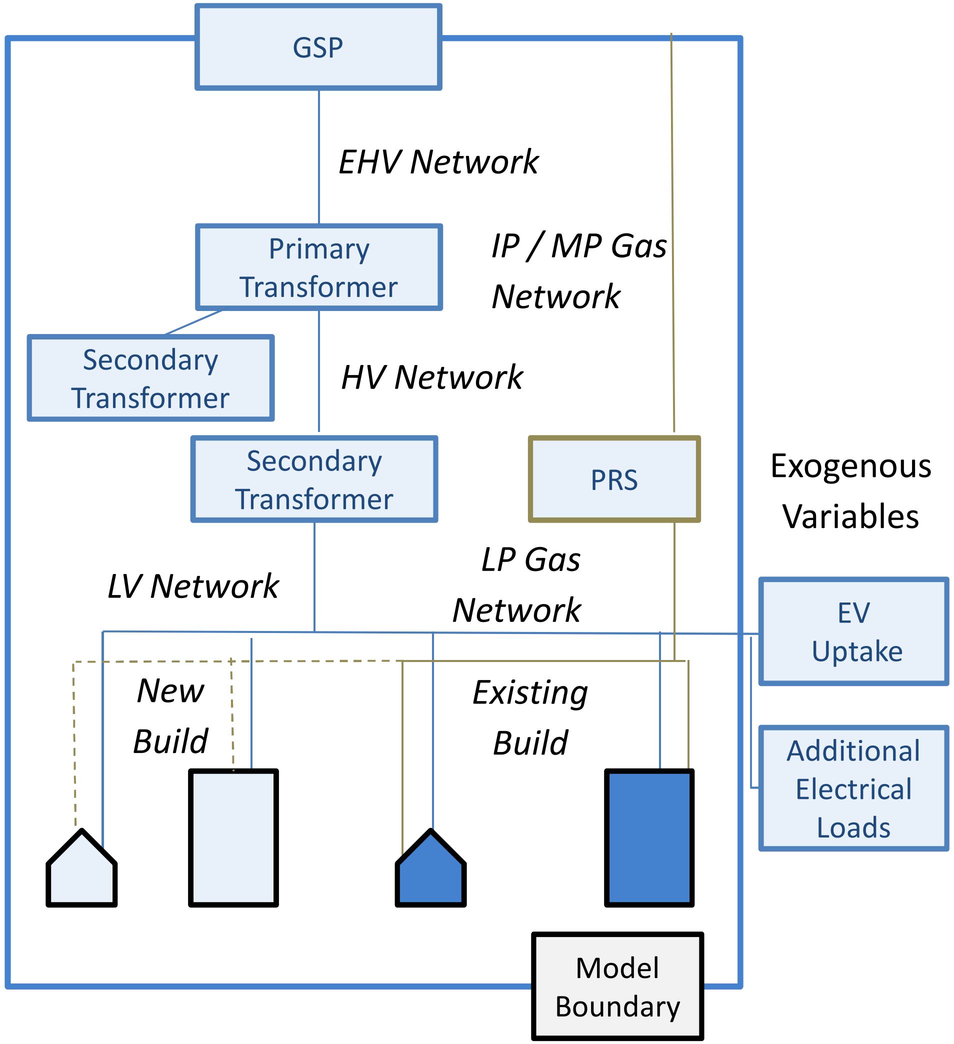
1. A town, representing all LV users downstream of an electrical grid supply point. This will comprise a representative distribution of building archetypes across several primary and secondary circuits.
2. As (1), with MV micro-CHP instead of, or in addition to, heat pumps.
3. A new build development of around 1,500 homes, built over 5 years, to quantify the situation under which new build is likely to connect to the gas network.

The technical and business-case ramifications for the gas network will also be assessed.

Model Boundary

The model considers the:

1. Gas and electricity supply and generation costs.
2. Electrical grid reinforcement requirements up to the GSP, and gas network repex.
3. Gas and electrical network operating costs.
4. GHG emissions pricing.



Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

Model Description

- The model is a top-down cost optimisation, rather than bottom-up consumer choice, or price-response model. Thus, in particular, all customers can be switched to gas heating in the MV optimisation.
- The model unit is the secondary transformers circuit; it determines and optimises the thermal demand dispatching associated with such circuits independently.
- Aggregate electrical HP load is calculated using a diversified total thermal demand profile and an average heat pump COP. The additional load profiles are taken from current WPD data, and EV uptake and charging predictions.
- Secondary circuit demands are then aggregated up to the primary, and then grid supply point level in Sincal.
- For a particular secondary circuit, with given HP uptake, the model attempts to limit the increase in peak demand to below the available headroom, using the SV, and then combined MV and SV mechanisms, specified below.

SV Optimisation

1. **Install decentralised thermal storage** in those homes on affected LV network branches,
2. **Increase LV network capacity**.

MV Optimisation – Domestic HP

1. Constrain peak total electrical demand by **shifting thermal load to gas boilers**.
2. Use hybrid heat pumps to **increase effective heat pump COP,** reducing electrical demand.

MV Optimisation – Micro-CHP

1. Use **micro-CHP to generate heat** and **electricity** locally.
2. For those houses with micro CHP, consider also using **HP and CHP operating in tandem**.

MV Optimisation – New Build

MV consideration is whether to **connect a new development to the gas network**, rather than commissioning a larger electrical connection (so the optimisation task is identical but the cost terms are capital, rather than operating costs).

Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

Electricity Grid Modelling

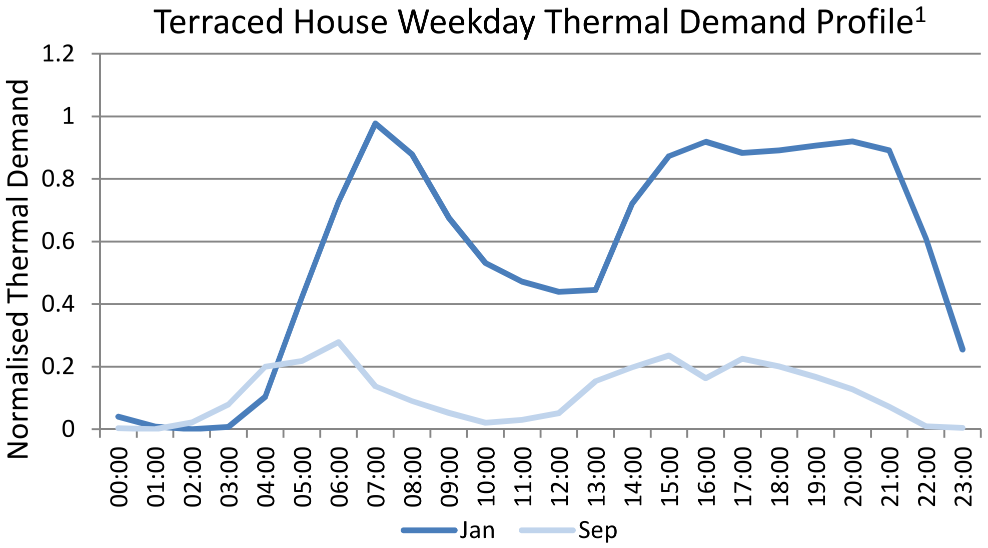
Using the Sincal model, the upstream effects of the secondary transformer load profiles can be aggregated, and the investment required on the higher voltage network branches determined.

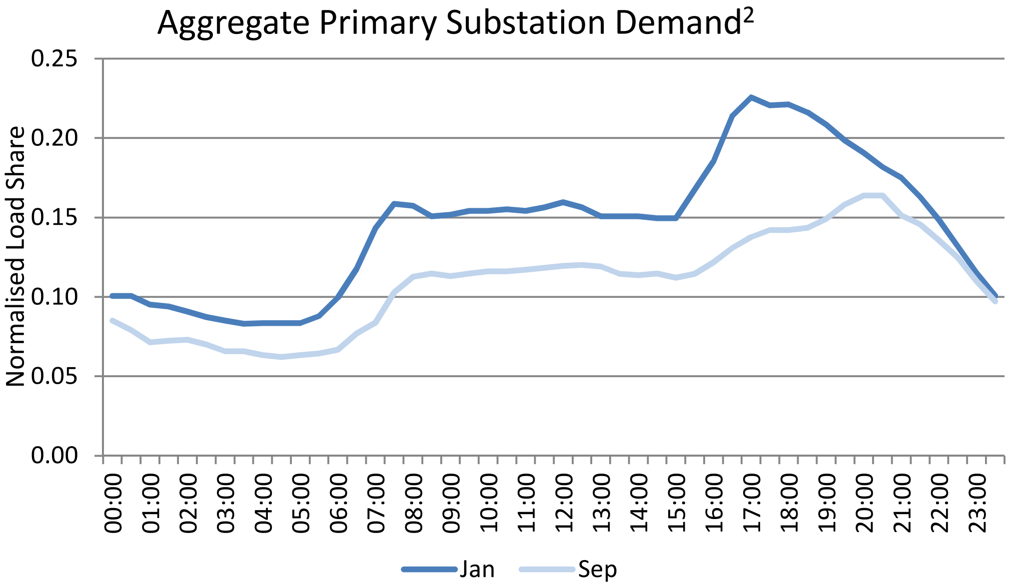
Gas Network Scenarios

For situations in which many LP branches are most cost effectively decommissioned, the technical and financial implications for upstream IP and MP gas network branches will be modelled using the Liwacom software.

Exogenous Variables of Interest

EV Uptake their **charging flexibility,** and local **DSM :** Electrical Grid load growth and stresses represent the key driver for the MV solution; these stresses will be strongly affected by EV uptake and the extent to which loads can be managed.



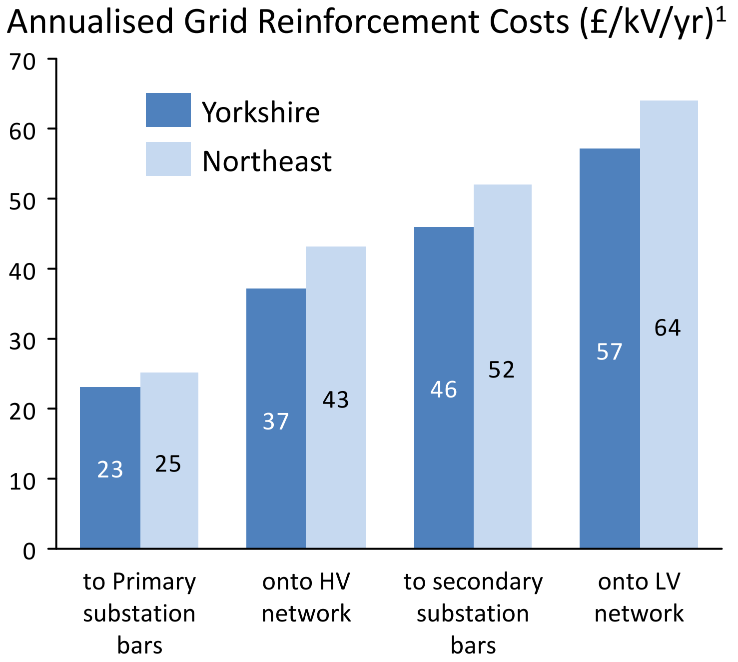


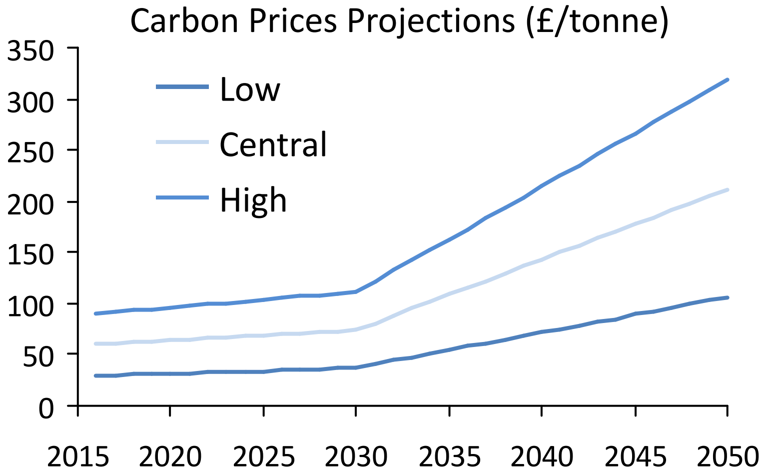
1: Source: EE Pathways to high heat pump penetration (CCC); Acklam Substation

2: Source: EE Substation Load Model (NGN)

Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

Model Parameter	Data Source
Electrical network reinforcement costs	Northern Powergrid data (right)
Gas network reinforcement schedule and associated costs	NGN 2012 data
Heat pump costs and COP data	EE study on Pathways to high heat pump penetration (CCC)
Hot water tank costs, sizes and U-values	
Gas boiler repex and opex	
Gas micro-CHP Costs	
Domestic thermal demand profiles, and associated diversification factors	
Air Temperature Data	UKMO Historical data
Hourly electricity prices	ESME and PLEXOS models
Gas prices	
Carbon prices	
Distribution of transformer capacities and available headroom	*Discuss with WPD*
Capacity of the higher voltage network branches	
Network structure	
EV Uptake and Charging Profile Scenarios	EE ECCO Model


Annualised Grid Reinforcement Costs (£/kV/yr)[1]


Carbon Prices Projections (£/tonne)

1: Source :Northern Powergrid Data published in the CLNR commercial arrangements report

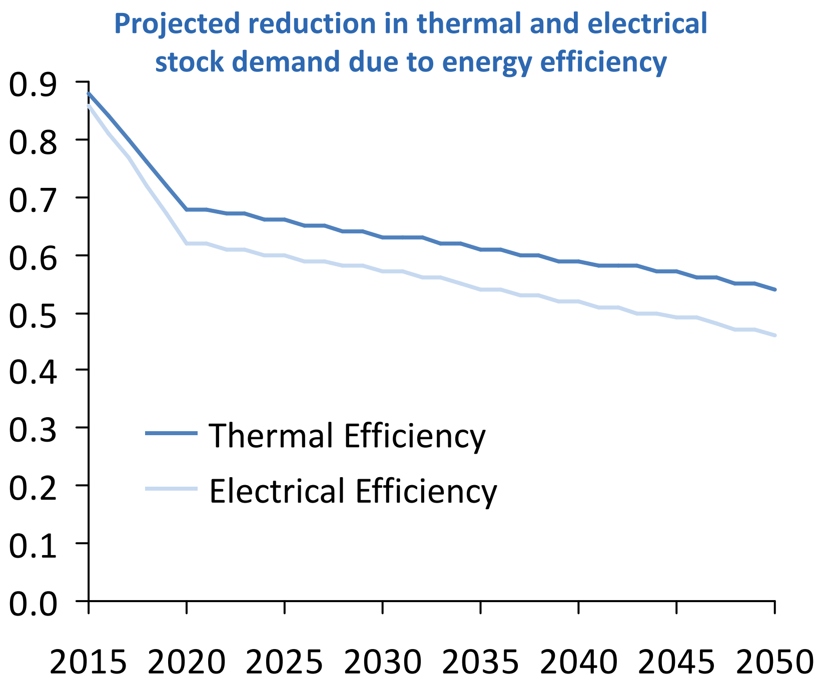
Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

Demand Profile Modelling

- Initial work has been undertaken to develop typical demand profiles for use in the analysis of this case
- For the retrofit case, demand profiles have been developed for a representative town of 150,000 population
- Data on the makeup of the housing stock has been used to define a set of house archetypes. The house archetypes are defined by the following parameters:

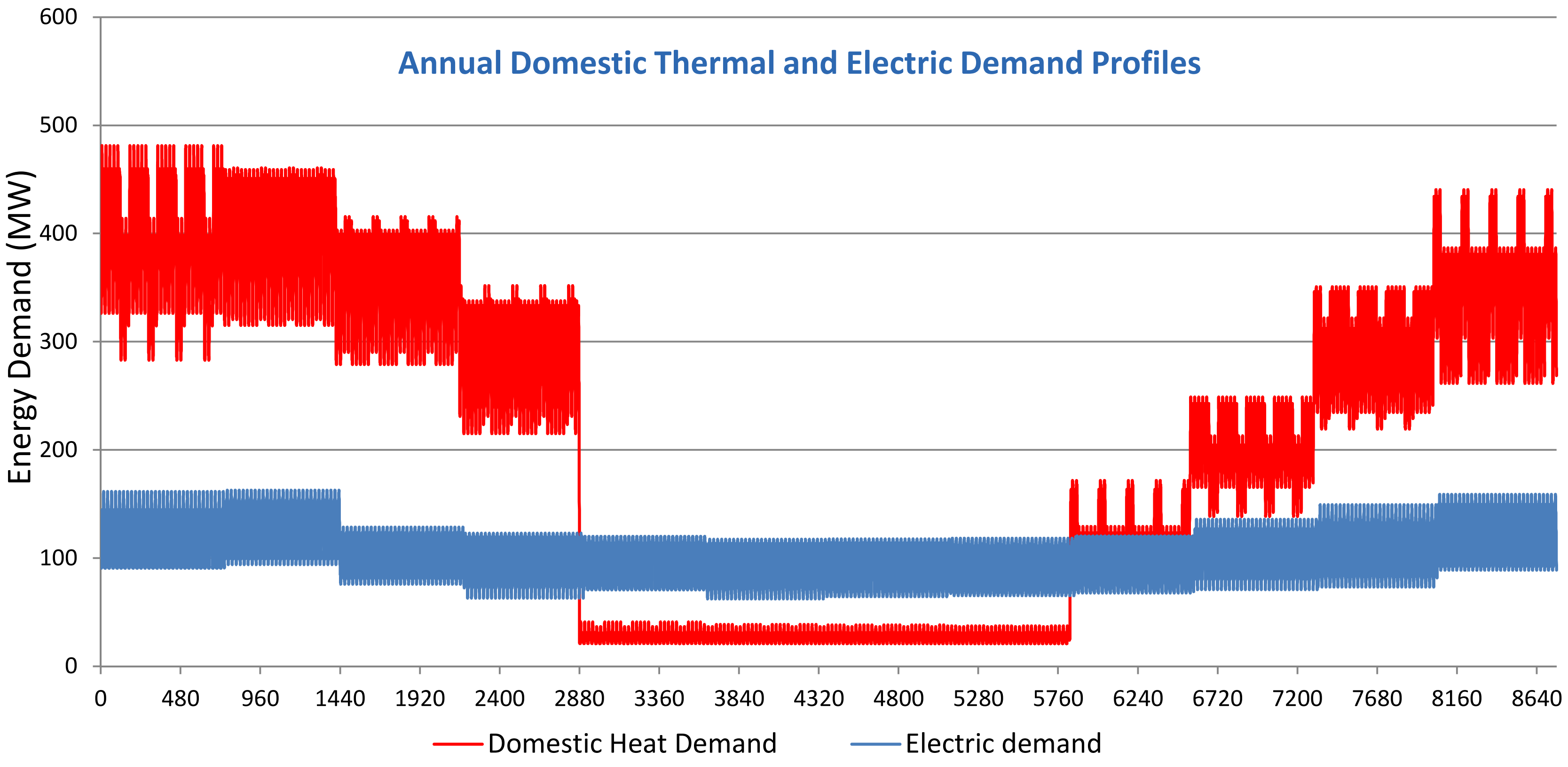
Parameter	Options
Heating Vector	Gas/Electricity
Type	Flat/Terraced/Semi/Detached
Age	Very Old/Old/Recent/New Build
Size	Large/Small
Location	Rural/Urban

- An electrical and thermal demand for each archetype is calculated using a SAP-based methodology
- Energy efficiency; thermal and electrical efficiency curves are shown in the figure; these are calculated based on an assumptions for the rate of treatment of the existing stock with energy efficiency measures and the rate of improvement in efficiency of electrical appliances.
- New Build; 1% of 2015 stock is assumed to be added each year, while 0.5% is assumed to be demolished



Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

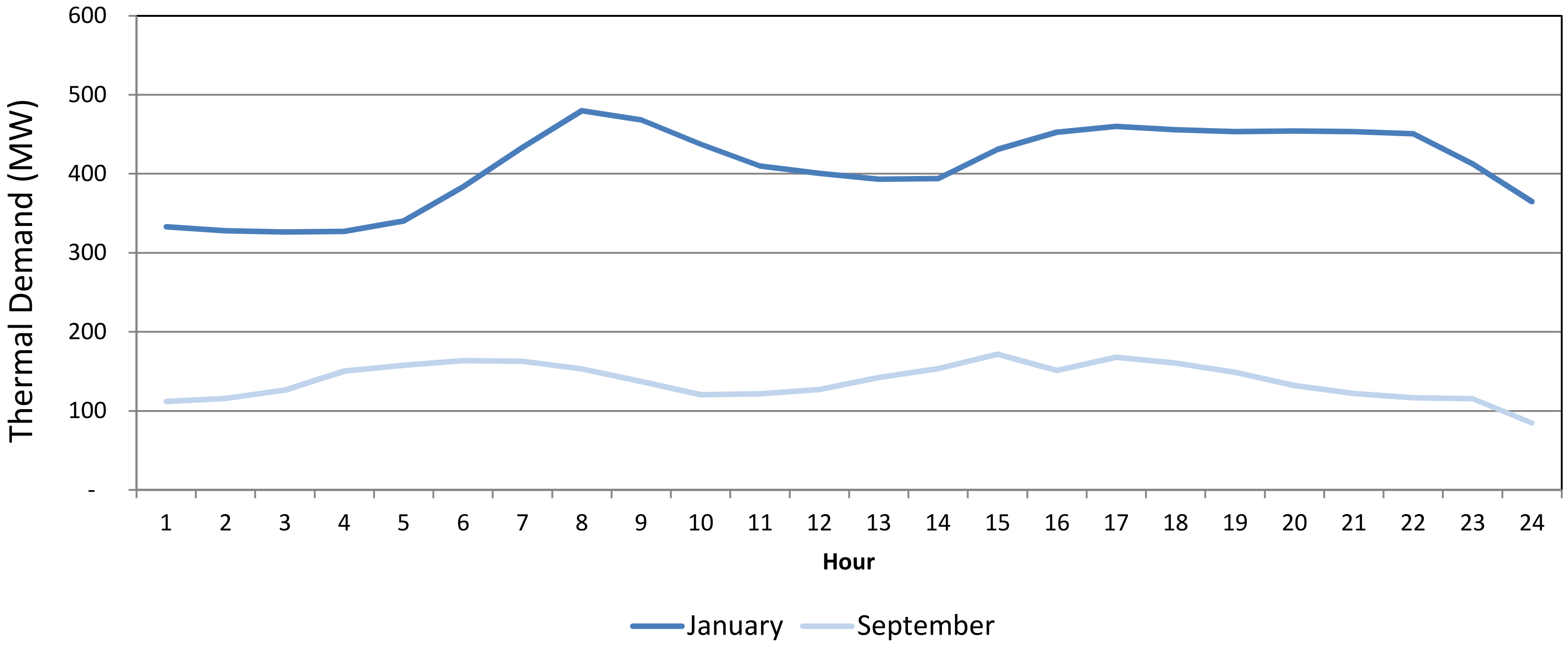
2016 – Electrical and Thermal Demand Profiles of a Typical UK Town



- The annual (8760 hours) thermal and electrical demand profiles are shown for a town of around 150,000 inhabitants; around the size of Oxford.

Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

Total Town Diurnal Thermal Demand Profiles



- The town diurnal heating demands for January and September are shown above; the total town domestic thermal demand is calculated based on aggregation of the demand profiles of the house archetypes (based on overall housing mix of the town).
- Electrical and thermal demand profiles can be constructed for smaller areas, e.g. at the level of individual network assets such as electricity distribution substations.

Electric heat pumps with gas boilers to meet peak heat demand in individual buildings

The Following Outputs will determine the SV and MV Optimal System Configurations and their Costs

Category	Case Study Instance
Electricity Network Reinforcement Cost	LV Grid Network Reinforcement Cost
	HV Grid Network Reinforcement Cost
Gas Network Costs	LP Gas Network Opex/Repex
	IP/MP Gas Network Opex/Repex
Electricity Costs	Total electricity generation cost
Gas Costs	Total gas supply cost
MV Infrastructure Capex	Hybrid heat pump premium
	Boiler and connection cost for new build
Carbon Emissions	Carbon emissions associated with gas and electrical consumption
Carbon Price	Price of above

	MV Solution
Incurred Costs	Increased emissions, increased gas network opex/repex
Avoided Costs	Deferred electrical network upgrades

MV-SV Value Matrix

The benefit derived in the MV case will be explored for a number of level of HP uptake and severity of constraint in the LV circuit.

		HP Uptake			
		40%	50%	60%	…
Headroom on Circuit	10%				
	20%				
	30%				
	…				

Gas CHP serving a district heating system and supplying power to heat pumps inside or outside the DH scheme at times of peak thermal demand

Case Description

This Case Study investigates the value to DH schemes of the ability to react to system level electrical price variation, and thereby reduce stress on the system generation and local distribution assets.

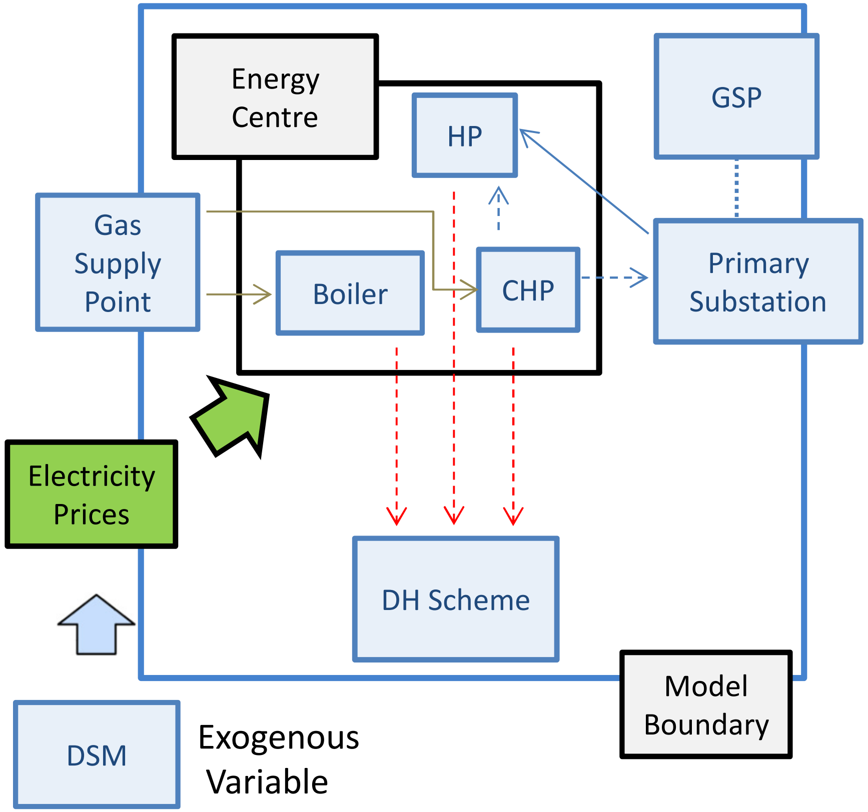
This case considers a DH scheme of several MW(th), connected to the HV electrical network for HP import and/or CHP export, and exposed to the associated connection costs.

The extent to which thermal and electrical demands are correlated, and therefore electrical prices reflect heat use, will strongly influence model behaviour; as such low and high electrification of heat scenarios will be investigated.

Model Boundary

In this case, the DH energy centre delivers the total scheme thermal demand whilst minimising the costs to the operator, taking into account:

- Hourly electricity import and export costs, calculated exogenously in the ESME model for a given energy system.
- Connection cost, given by the required HV network reinforcement costs.
- Seasonal variation in COP for air source HP, and the availability and effect of low grade heat sources.



Energy Centre preference order of thermal plant is determined by the electricity import and export prices.

Gas CHP serving a district heating system and supplying power to heat pumps inside or outside the DH scheme at times of peak thermal demand

Model Structure

This Case Study investigates using a marginal cost model. For each of the 8760 timestamps, the model meets the scheme thermal demand using the lowest cost configuration, and the electrical import and export prices capture the network costs and benefits.

Within the model:

- Heat pump COP will vary seasonally. It can also be flexed exogenously to represent the availability of low temperature waste heat.
- SV configurations include only the choice of principal plant (CHP or HP) and the backup boiler,
- MV solutions has a range of supply configuration options, shown in the table opposite.

SV Optimisation

CHP or HP only DH schemes (with gas boiler sized to 1:20 peak) will be considered as the "twin" SV configurations, so the SV scheme meets the thermal demand with the lowest cost plant over the 8760 hours. Note that as the electricity grid decarbonises and carbon prices increase, the optimal SV configuration will depend on the run year.

MV Optimisation

Model Configuration	Description	Electricity Price
1	Run CHP, export electricity. Meet any additional demand using the boiler.	Very High
2	Run CHP, use electricity to run HP, meet any additional demand using the boiler.	High
3	Run CHP, use electricity to run HP. Meet additional demand with remaining CHP/HP, then boiler.	Low
4	Run HP from electricity network, meet any additional demand using the boiler.	Very low
5	Run Boiler only	Low, low COP

Gas CHP serving a district heating system and supplying power to heat pumps inside or outside the DH scheme at times of peak thermal demand

Electricity Price Time series

The ESME and PLEXOS models create a fundamental system energy price time series, which reflects the supply cost curve and demand profiles for a particular system future. These prices therefore capture the hourly system cost of marginal electrical demand in that future. In order to fully understand the MV value, annual electrical price series will be created for a variety of potential future energy systems.

Electricity Export Prices

Although PPA structures often smooth out variations in electrical price, the “fundamental” export price, which captures the system benefit of CHP electrical export, will be given by the wholesale price (not including distribution and balancing charges).

A DH scheme with CHP, HP and thermal storage has considerable flexibility, and could provide a range of ancillary services to the grid; the co-benefits of these will be investigated for different DH scheme configurations.

Subsidy

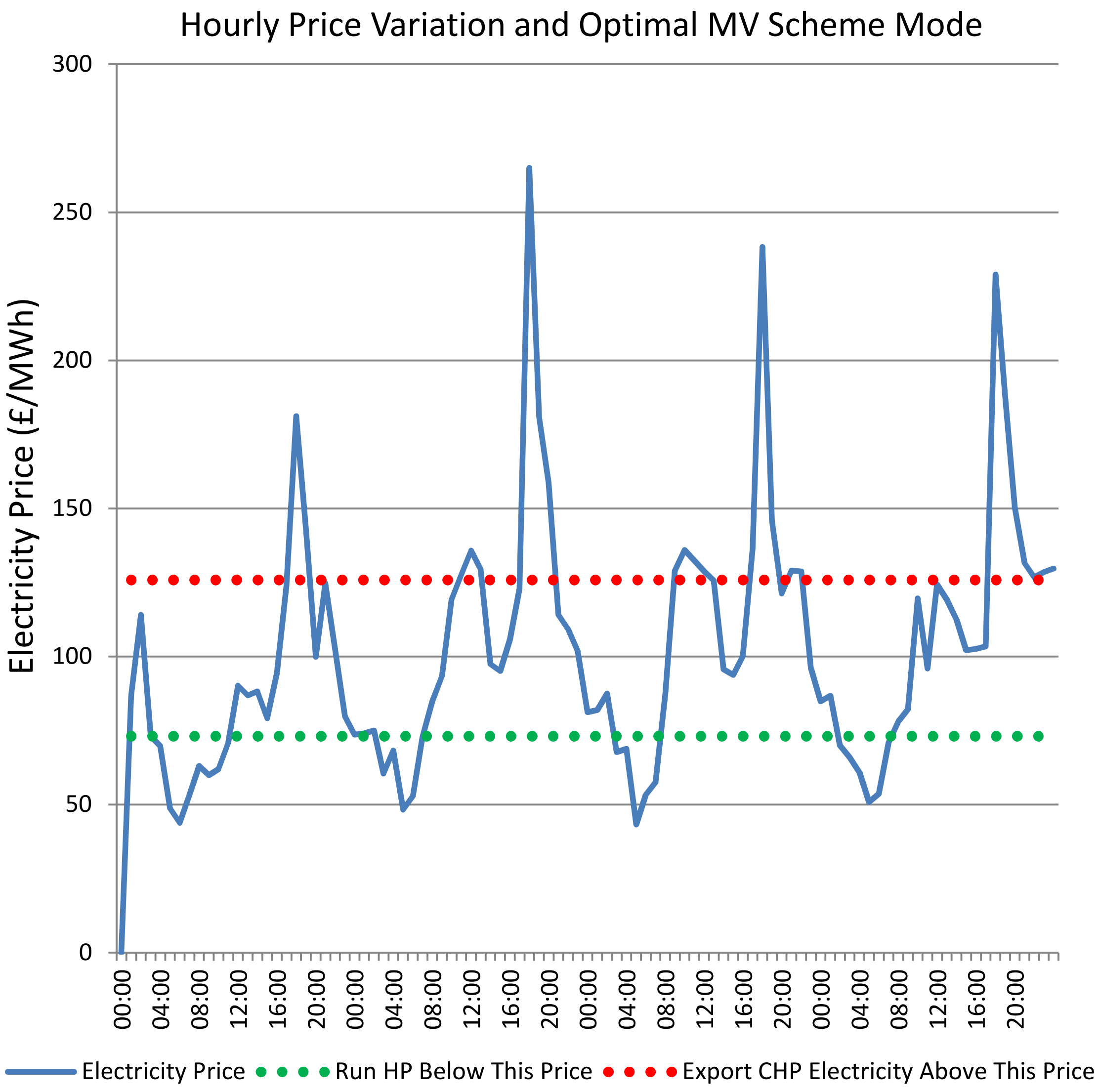
Although the economic model considers the options of the DH scheme operator, RHI or other subsidy is not considered in the model, since:

- ESME carbon prices should reflect marginal emissions abatement costs, and these are included in the energy costs
- Long term RHI policy is very uncertain.

Exogenous variables of interest

- **Generation mix**, and associated electrical price time series (see above)
- **Electrification of heat,** and the associated coupling of thermal and electrical demand
- **EV Uptake,** particularly if V2G provides a large source of cheap DSM

Gas CHP serving a district heating system and supplying power to heat pumps inside or outside the DH scheme at times of peak thermal demand



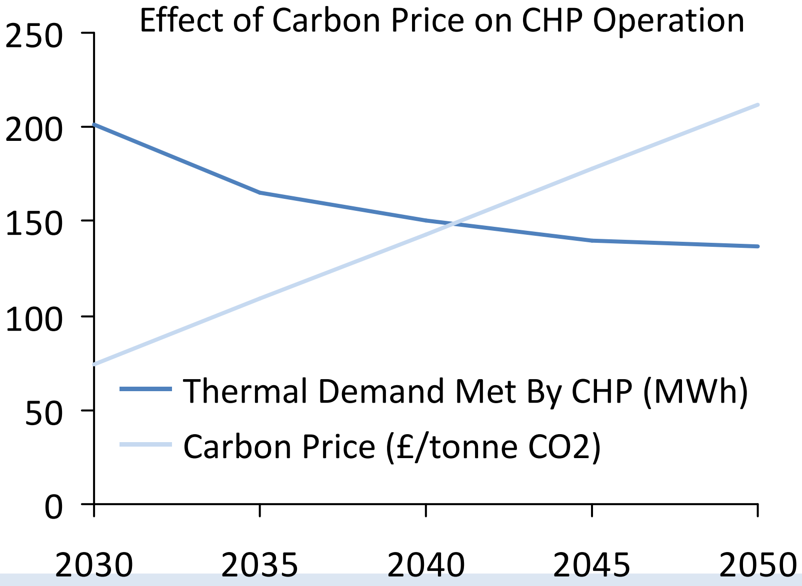
Model Parameter	Data Source
Generation mix scenarios	ESME and PLEXOS models; CCC HP Pathway model
Electrification of heat	
Electrical prices and variation associated with above.	
Gas costs	ESME model
Electrification of transport	ECCO model
Large scale HP capex and learning curves	EE Heat pump in DH study (DECC); EE HNDU DH master planning studies.
Large scale CHP capex and learning curves	
Large scale boiler capex	
Thermal demand profiles	EE study on Pathways to high heat pump penetration (CCC)
Thermal diversification factors	CIBSE DH Guidelines

Gas CHP serving a district heating system and supplying power to heat pumps inside or outside the DH scheme at times of peak thermal demand

The Following Outputs will determine the SV and MV Optimal System Configurations and their Costs

Category	Case Study Instance
Electricity Costs	Total Electrical Import
	Total Electrical Export
Gas Costs	Total Gas Costs
Network Connection Costs	HV electrical connection Cost
MV Infrastructure Capex	HP and CHP prices
	Boiler and connection cost for new build
Annualised Generation Infrastructure Costs	Annualised Generation Infrastructure Costs
Carbon Emissions	Carbon emissions associated with gas and electrical consumption
Carbon Price	Price of above

	MV Solution
Incurred Costs	Additional plant and connection costs.
Avoided Costs	Lost revenue from high import and low export electrical prices.



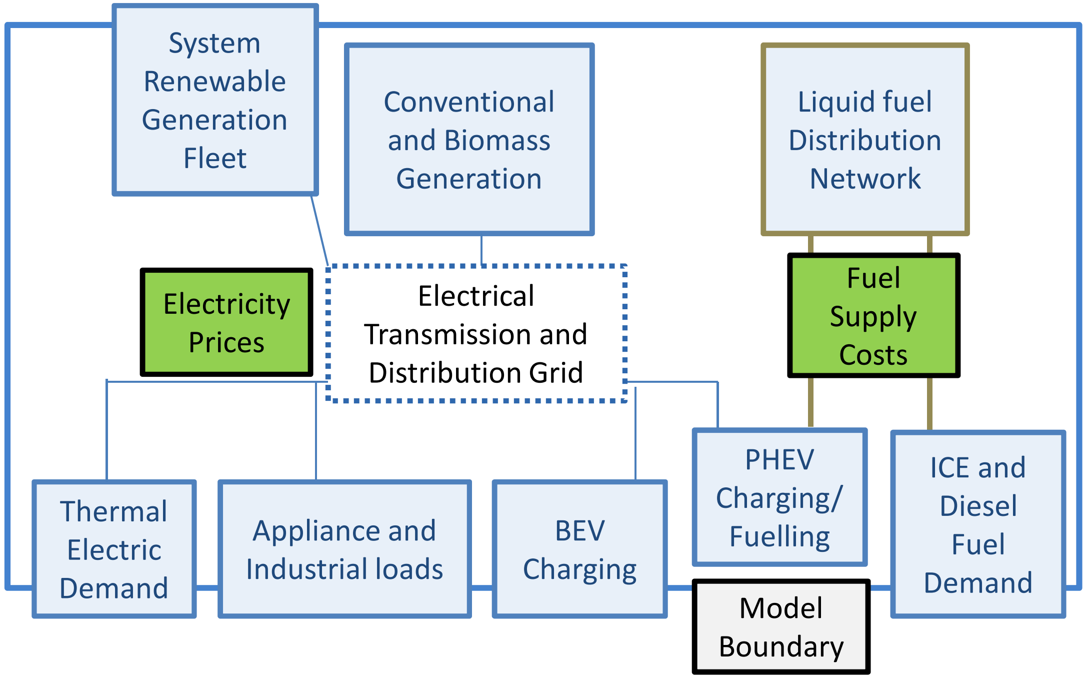
PHEV displacing electrical demand with liquid fuels

Case Description

In this scenario, the system level effect of a low wind year on a high renewable, highly electrified energy system is investigated, and the opportunity for PHEV fuel switching to reduce stress on the network quantified.

Model Boundary

The model considers the total system electrical load, and the entire generation fleet. In parallel, it also considers the system level demand for liquid fuels.
The transmission and distribution networks are not endogenously modelled, but do contribute a cost component to electricity prices.
However, the supply costs of the liquid fuel delivery systems are endogenously calculated based on the system demand for liquid fuels and the projected fuel "distribution network" capacity.



The model determines the marginal electrical generation and liquid fuel supply costs endogenously, based on the exogenous fuel costs , generation fleet and the ECCO projected size of the liquid fuel delivery and sale network.

PHEV displacing electrical demand with liquid fuels

Model Structure

This model quantifies the PHEV energy demand that can be moved off the electrical system in an extremal low wind year. Hourly electrical and liquid fuel marginal supply cost curves are calculated from:

1. Total system demand
2. Available generation and distribution assets, respectively
3. Additional assets that might be required, and their capital costs

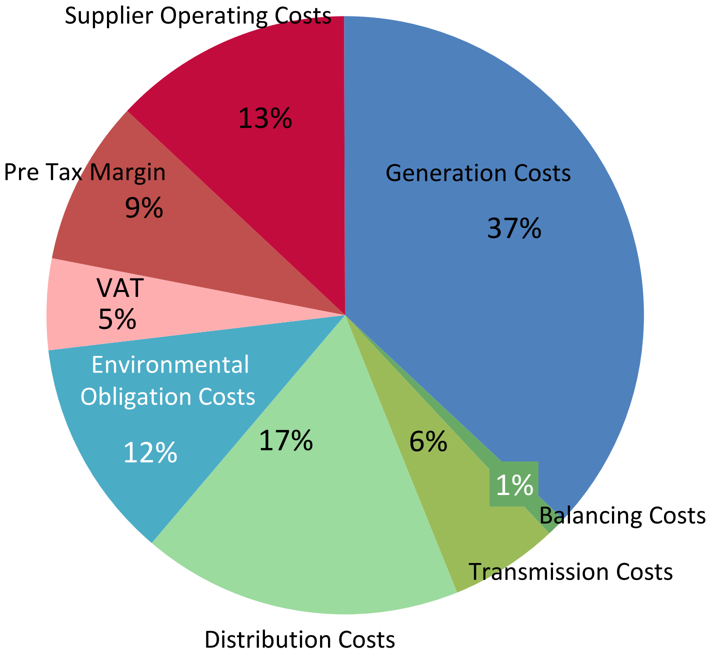
The exogenous electrical demand is given by the energy requirements for heat, appliances and BEVs, the liquid fuel demand from the size of the ICE and diesel fleets and their refuelling schedules.

The model then determines under what conditions the energy demands of PHEVs can be most cheaply met though further electrical supply or liquid fuels.

Note that:

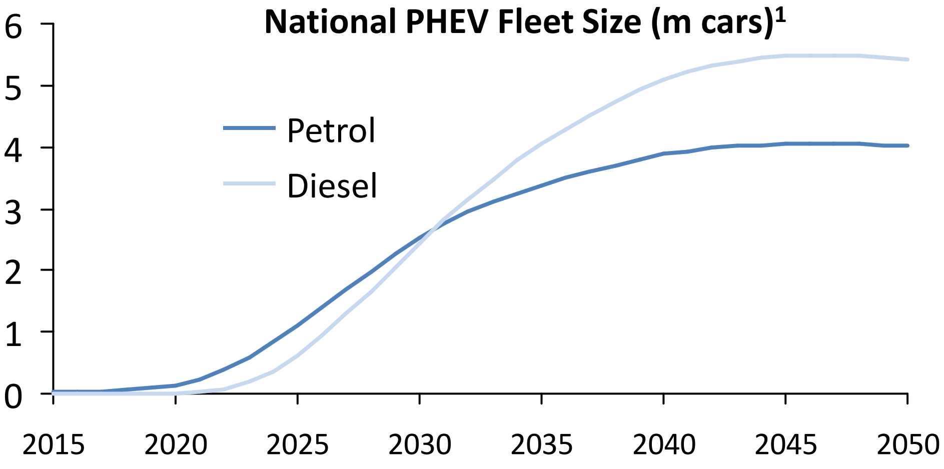
- The electrical transmission and distribution systems are not explicitly considered; as EV charging is flexible and by construction this is a high EV uptake scenario, it is assumed that the required electrical network capacity has been built. A surcharge for distribution, grid balancing and other transmission charges is applied.
- The capacity of the liquid fuel delivery network is modelled in-line with the projected reduction of throughput and closure of filling stations, and historical data on periods of fuel stress.
- In extremal cases, there may be value in using the vehicle fleet as a large distributed generation asset; powering their batteries while driving and discharging this electricity to the grid once parked.
- Fuel duty is not considered, nor are the effects of increased electrical or fuel prices on driver behaviour.

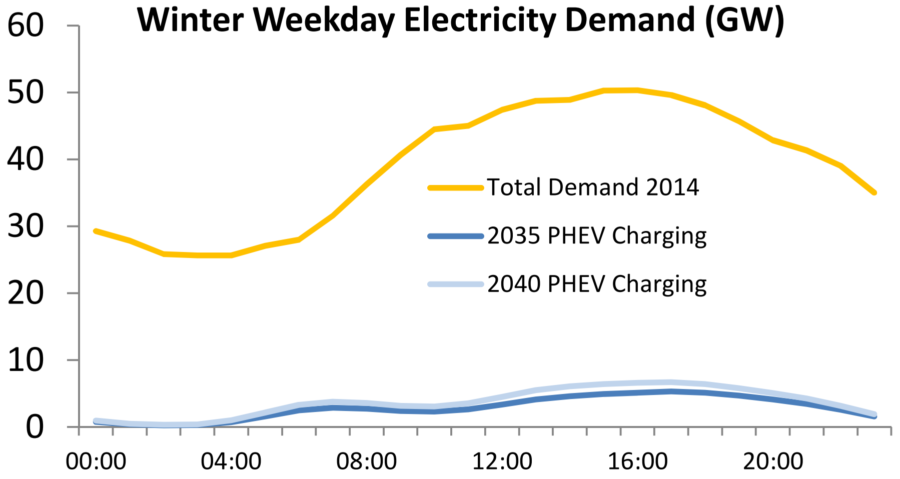
2015 Breakdown of Retail Electricity Costs

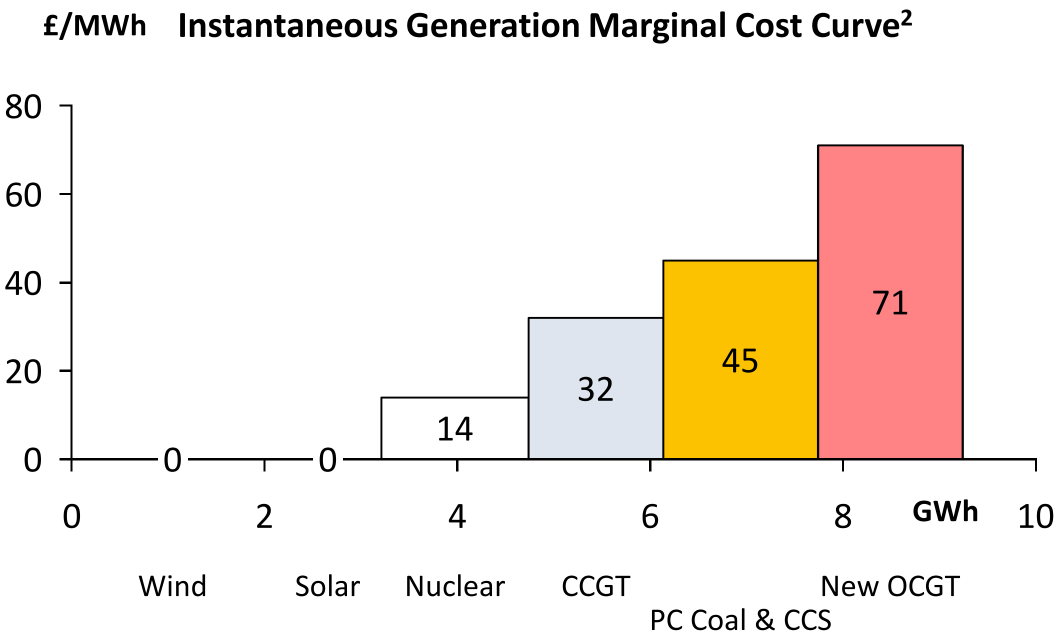


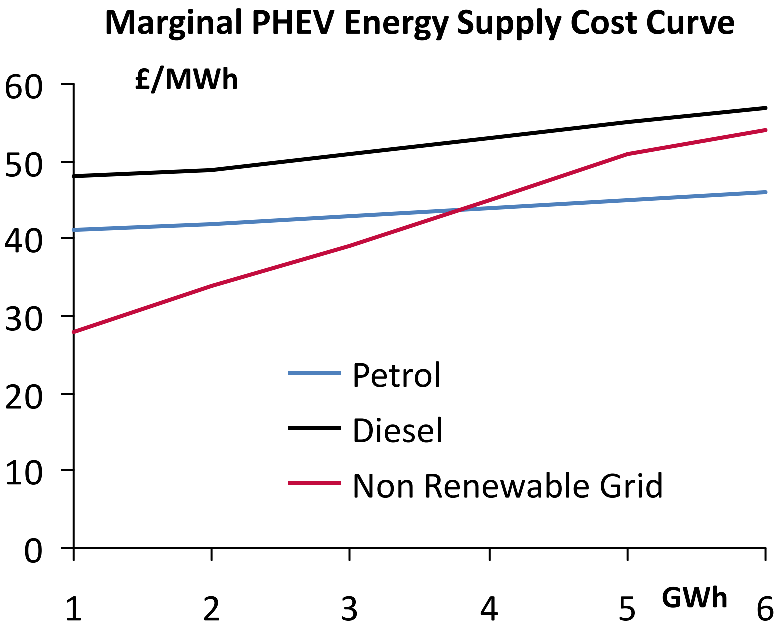
Source: Ofgem. Note that in particular, balancing costs are likely to rise as intermittent generation increases its mix share

PHEV displacing electrical demand with liquid fuels


National PHEV Fleet Size (m cars)[1]


Winter Weekday Electricity Demand (GW)


£/MWh Instantaneous Generation Marginal Cost Curve[2]


Marginal PHEV Energy Supply Cost Curve

[1] Source ECCO

[2] Source: ESME

PHEV displacing electrical demand with liquid fuels

SV Optimisation

The SV model:

1. quantifies the construction of the backup generation required to meet the PHEV BAU electrical demand,
2. calculates the relevant annualised capex, the associated fuel costs and emissions or CCS costs.

MV Optimisation

The MV model :

1. Switches PHEVs to petrol only operation in decreasing order of efficiency, in a way that is (at worst) cost neutral to those drivers, until the cost of further petrol supply exceeds the electrical charging price.
2. (Where all PHEVs are powered by petrol) determines the cost of supplying V2G electricity by powering the battery from the fuel engine while driving.
3. Calculates fuel and supply costs of petrol for the associated spike in network throughput.
4. Determines the associated environmental costs.

Model Parameter	Data Source
Vehicle Driving profiles	ECCO
PHEV charging profiles	
Petrol distribution network and station opex /obsolescence value	
Projected marginal petrol delivery cost curve	
V2G Capex	
Grid-to-wheel efficiency projection curves	
PHEV and BEV uptake curves	
PHEV fuel use split	NTS[1] Data
Petrol and Diesel (Oil) Cost Projections	ESME
Electrical Price Projections	
Carbon Price Projections	

Exogenous variables of interest

- The degree of **electrification of heat**, will contribute significantly to the peak electrical demand, particularly as peak electrical demand occurs on cold winter week day evenings.
- **CCS prices** will contribute significantly to the competitiveness of fossil fuel generation.

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[1]: National Travel Survey

PHEV displacing electrical demand with liquid fuels

The Following Outputs will determine the SV and MV Optimal System Configurations and their Costs

Category	Case Study Instance
Electricity Costs	Total Electricity Generation and Costs
Liquid Fuel Costs	Total (Untaxed) Liquid Fuel Costs
MV Infrastructure Capex	V2G Costs
Generation Infrastructure Costs	Annualised Peak Plant Costs
Carbon Emissions	Carbon emissions associated with electrical and liquid fuel consumption
Carbon Price	Price of above

	MV Solution
Incurred Costs	Emissions associated with PHEV petrol use, costs associated with distribution spike in petrol distribution “network”.
Avoided Costs	Avoided backup generation plant costs, carbon emissions or CCS of fossil fuel plant,

RES-to-Hydrogen (Transmission Level)

Case Description

This case study, reviews the system level potential for surplus wind generation to generate $H_{2,}$ which can then be stored or exported. The diagnostic questions are:

1. how wind power utilisation and penetration in a region with low demand and constrained electrical export capacity can be increased, and
2. how system level oversupply can best be most economically moved to times or locations of higher demand.

in the medium and long terms respectively.

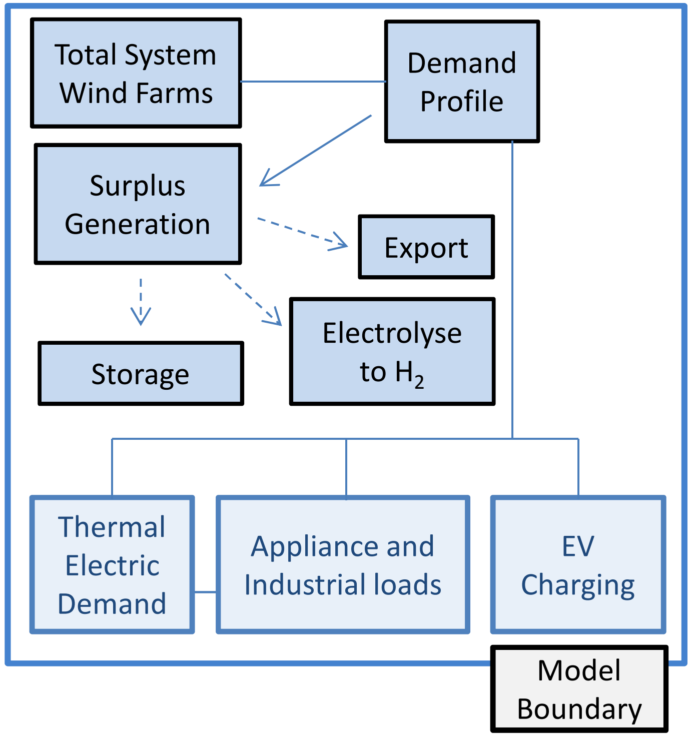
The model will:

1. focus on a particular region in UK with a generation mix dominated by wind, linked to the rest of the UK via transmission circuits of a limited export capacity (e.g. the Scottish Highlands, Cornwall, East Anglia, north Wales).
2. consider the aggregate system at a high level of wind as a share of total generation.

In the SV case, generation surplus can be

- Exported to the rest of UK (by increasing interconnector capacity) in (1)
- Curtailed
- Stored (by building grid level storage)

While in the MV case generation surplus is converted to H_2 (and potentially then CH_4) via electrolysis. A scenario in which the produced H_2 is injected into a H_2 network supplying a city will be studied as a separate Multi-Vector (MV) sub-case.



Model Boundary

The model considers the national (and regional, where applicable) demand, as well as the total wind generation profile.

Where a city's gas demand is also considered, the daily or monthly demand for H_2 is moved inside the model boundary.

RES-to-Hydrogen (Transmission Level)

Model Description

For a given annual hourly profile of generation vs demand in the UK, (and a sub region, where applicable), the model

- Determines the hourly total wind generation
- Calculates the oversupply, based on the national (and in (1), regional) demand profiles (and interconnector capacity)

The model then optimises over what infrastructure should be built to store or electrolyse this surplus.

SV Optimisation

- (in (1)) Increase regional export capacity to the rest of UK via transmission network reinforcement
- Curtail excess of generation in the region by spilling wind generation
- Install electrical storage.
- For case of a regional network, H_2 requirements are met by SMR with CCS

MV Optimisation- Case 1

- Build electrolysers, allowing the **conversion of surplus generation to H_2**. This H_2 will be blended into the gas grid (up to a predefined limit), and subsequently sold on a commodity market. (The sale price is given by the gas energy price less the carbon price).
- H_2 storage can be installed if needed.

MV Optimisation- Case 2

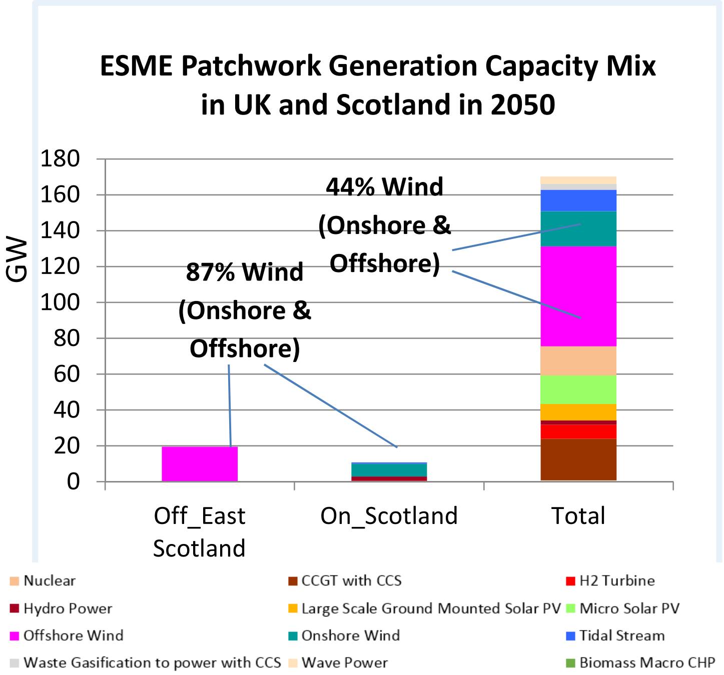
- As in Case 1, with the option that H_2 can be **upgraded to CH_4** and injected into the gas network without limit; (the CH_4 is sold at a gas wholesale price less the carbon price).
- In Cases 1 & 2, the gas grid network is seen as a “sink”, therefore **balancing issues are neglected**.

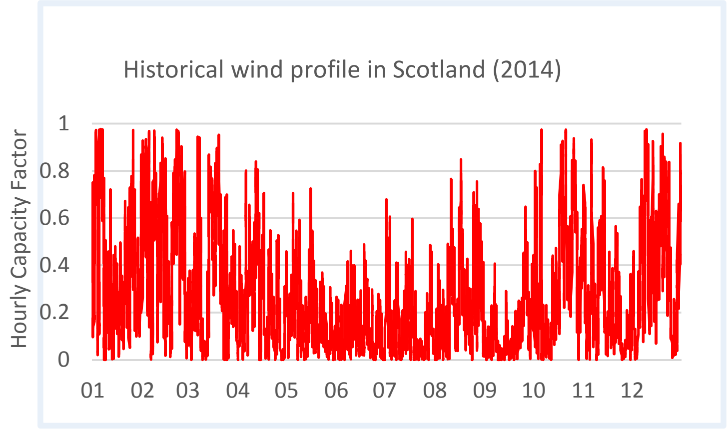
MV Optimisation- Case 3

- As in Cases 1 & 2, with the difference that the electrolysis-produced **H_2 is used to supply an existing city H_2 network** (with a given daily or weekly demand profile.
- In this case, the model **balances the H_2 supply and demand** (via electrolysis and SMR)

RES-to-Hydrogen (Transmission Level)

Model Parameter	Data Source
National & regional timesliced electrical demand profile	ESME model outputs
National & regional hourly electrical demand profile	Post-conversion of ESME time-sliced data to hourly based on historical demand profile
National & regional time-sliced generation capacity mix	ESME model outputs
Regional hourly wind generation load factors	Calculated based on wind speed data from Anemos database
Regional H_2 network monthly demand	Derived based on Leeds Citygate H21, NGN report/ESME
National & regional hourly generation profile	PLEXOS dispatch model using ESME capacity mix
Resource and emissions prices (gas, H_2, CO_2)	ESME model outputs (shadow prices)
Investment (capital) costs, fixed and variable O&M costs per technology- H_2 plant (Electrolysis), H_2 Plant (SMR with CCS), Methanator	ESME database & Publicly available data
Transmission network reinforcement costs	ESME database
Regional transmission export capacity	NG ETYS 2015 plans combined with ESME model output
Wholesale hourly electricity prices	PLEXOS dispatch model using ESME capacity mix


ESME Patchwork Generation Capacity Mix in UK and Scotland in 2050


Historical wind profile in Scotland (2014)

Source: ETI ESME model

RES-to-Hydrogen (Transmission Level)

The Following Outputs will determine the SV and MV Optimal System Configurations and their costs

Category	Case Study Instance
Wind power generation costs (£m)	Annualised investment costs for wind farms
	Fixed & Variable O&M costs for wind farms
Transmission network reinforcement costs (£m)	Annualised investment costs for the increase of Scotland's export capacity to rest of UK
	Fixed costs for transmission network reinforcement
Electricity and H_2 storage costs (£m)	Annualised investment costs for electricity & H_2 storage technologies
	Fixed & Variable O&M costs for storage technologies
Hydrogen/ bio-methane generation costs (£m)	Annualised investment costs for electrolysis (MV Case 1)/ Methanator (MV Case 2) and SMR with CCS (MV Case 3)
	Fixed & Variable O&M costs for technologies above
Revenues (£m) from sales across the model boundary	Revenues from selling wind power at wholesale electricity prices (SV case)
	Revenues from selling H_2 (MV Case 1) or biomethane (MV case 2)
Gas purchase costs	Costs of purchasing gas as fuel for H_2 production via SMR with CCS (MV Case 3)

	MV Solutions
Incurred Costs	Electrolyser and H_2 storage capital & operational costs
Avoided Costs	Transmission network reinforcement costs
	Wind generation curtailment cost
	Reduced carbon emissions and gas import requirements (MV-Case 3)

RES-to-District Heating (Distribution Level)

Case Description

In this case study the question is how we can increase the distributed wind power penetration in a constrained part of the distribution network by converting electricity to heat.

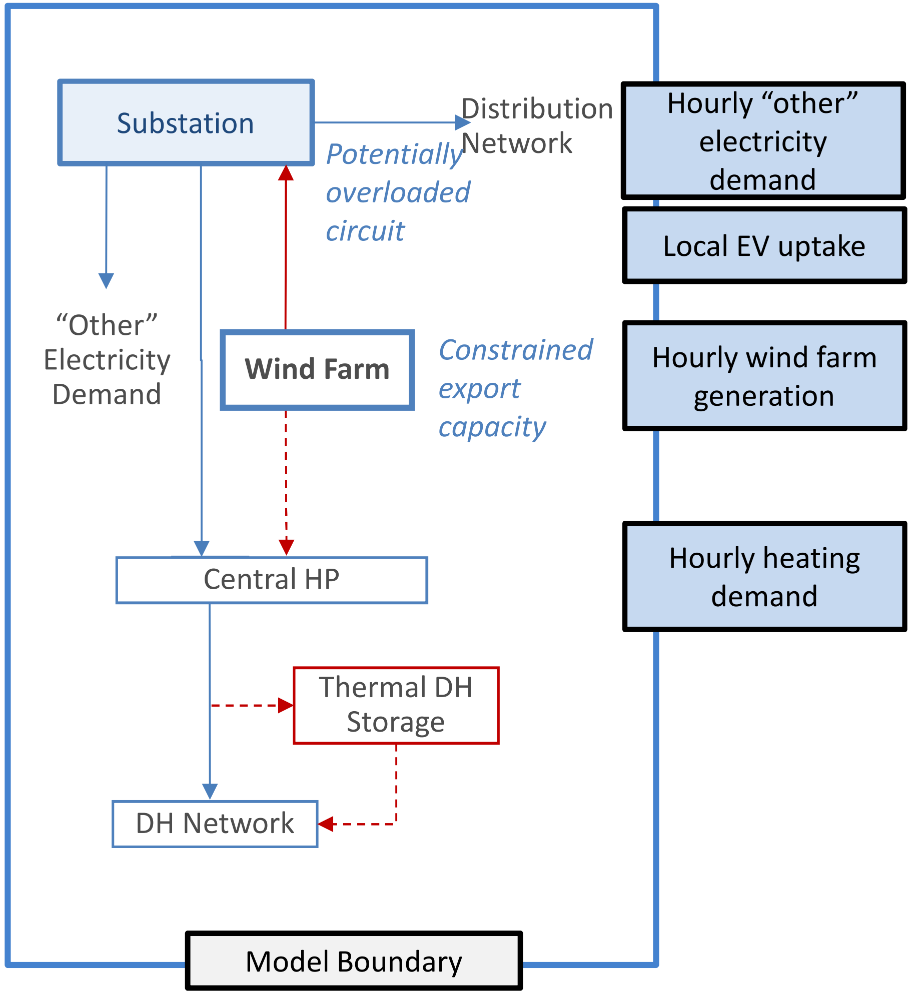
The following scenario will be studied for a snapshot year in the future (e.g. 2050):

- A new large wind farm (over 10 MW) to be connected on the distribution network with a constrained connection offer due to network overload risk
- A district heating (DH) system based on a large-scale heat pump (HP) supplying the heating demand of a nearby medium-size city.
- SV case: Unlimited wind export is only allowed after network reinforcement or is otherwise curtailed when network constraints are violated
- MV case: Surplus wind is converted to heating via the HP

Model Boundary

The key inputs in the model are the following:

- Hourly electricity and heating demand profile of an archetypal city in the UK
- Wholesale power prices in a world where UK capacity mix has high penetration of renewables (>25%) e.g. Patchwork/Clockwork scenarios
- Hourly demand from EV's



RES-to-District Heating (Distribution Level)

Model Description

For given wind generation export and substation demand profiles, the net power export on the constrained circuit will be derived and compared against its (seasonal) rating.

The model will calculate the **total cost to the wind farm developer** and quantify the capacity requirements in the SV and MV cases:

a) Wind curtailment
b) Network reinforcement
c) Conversion of wind power to heating and storage in a heat store

The impact of varying the wind farm's rated export capacity, and the maximum network export capacity will be studied.

SV Optimisation

- Curtail wind generation when network constraint is violated (circuit's rating is exceeded)
- Carry out the required network reinforcement works to allow for the wind farm's unlimited export.

MV Optimisation

- When the wind farm's power export exceeds its permissible limits (due to network constraints violations), the **surplus wind** will be used to **supply the existing large-scale HP feeding the DH system** in the nearby city.
- **Thermal storage** will be built for the times that wind generation exceeds the city's heating demand.
- Storage capacity will optimised for the year-long amount of generation that cannot be absorbed on a hour-to-hour basis by the DH system.

RES-to-District Heating (Distribution Level)

Model Parameter	Data Source
Wholesale electricity prices	PLEXOS model using ESME results
Regional hourly wind generation load factors	Calculated based on wind speed data from Anemos database
Seasonal and hourly heating demand of an archetypal city in UK	Element Energy DECC HP model
Hourly ‘other’ electricity demand	WPD data
Local EV uptake	Derived by scaling down the regional results given by ESME
Hourly EV electricity demand at substation level	Element Energy EV model
Investment (capital) costs, fixed and variable O&M costs of thermal storage	ESME database (District Heat Storage)
Distribution network reinforcement costs	ESME database (Capital cost for capacity increase)
Technical characteristics per technology type	ESME database and Element Energy data

RES-to-District Heating (Distribution Level)

The Following Outputs will determine the SV and MV Optimal System Configurations and their costs

Category	Case Study Instance
Wind power generation costs (£m)	Annualised investment costs for wind farms
	Fixed & Variable O&M costs for wind farms
Distribution network reinforcement costs (£m)	Annualised investment costs (SV)
	Fixed costs (SV)
Thermal storage costs (£m)	Annualised investment costs for heat store (MV)
	Fixed & Variable O&M costs for heat store (MV)

	MV Solution
Incurred Costs	Heat storage capital & operational costs
Avoided Costs	Network reinforcement costs
	Wind generation curtailment

RES to Distributed Smart Heating

Case Description

This case study investigates the potential, in areas of weak or isolated electricity networks, for domestic heat demand to:

1. Act as a store for renewable generation that would otherwise be wasted or curtailed
2. Provide frequency response or other grid balancing services.

Areas of interest are **low-density**, **high wind-speed**, rural settings with **limited gas network,** such as:

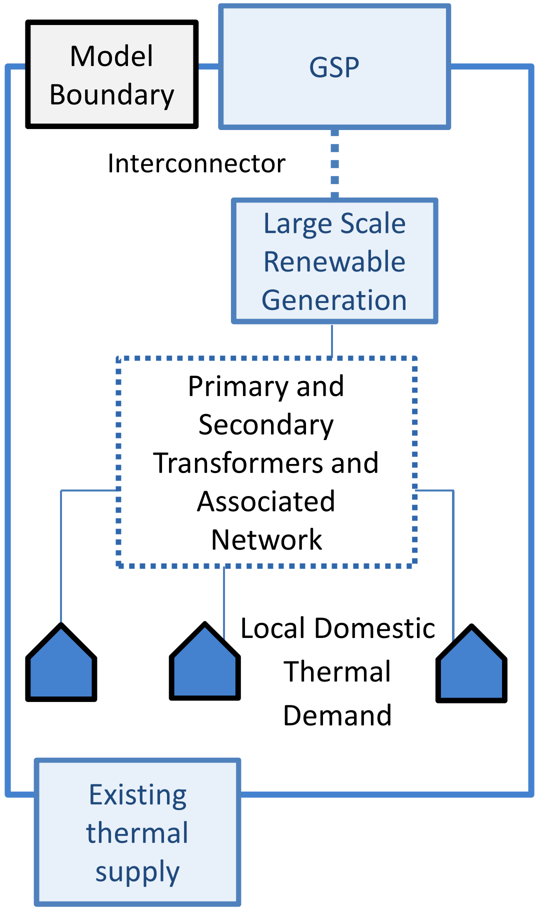
- Mull (where the ACCESS project is running)
- Carmarthenshire, the Scottish Highlands

Model Boundary

This model considers the generation of a large wind farm and the concurrent domestic thermal demand in the area.

The costs considered are thus:

1. The supply of heating.
2. The value of the curtailed electricity.
3. The cost of grid balancing services.



Model Boundary

GSP

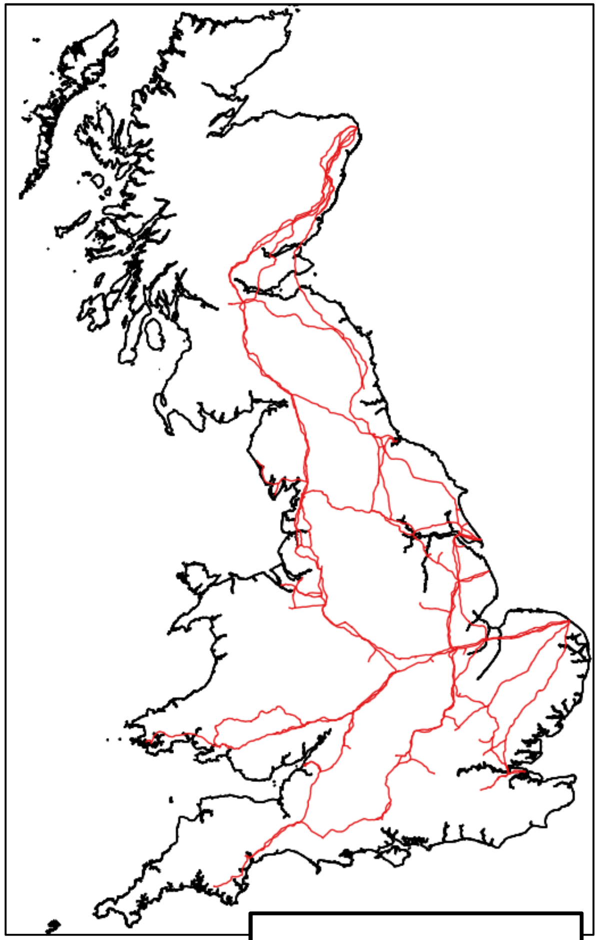
Interconnector

Large Scale Renewable Generation

Primary and Secondary Transformers and Associated Network

Local Domestic Thermal Demand

Existing thermal supply



UK HP Gas Network

RES to Distributed Smart Heating

Model Description

This model determines the generation curtailed from the windfarm based on the network constraint. It then builds infrastructure to reduce this amount in the SV and combined solutions.

SV Optimisation

In the SV case, the model:

1. builds an interconnector of optimal size for the demand profile on the other side of the interconnector, and
2. independently meets the costs of meeting the thermal demand of all users through their existing heat supply mechanism.

MV Optimisation

The MV model determines:

1. The optimal scale and type of electrical heating system (based on either HPs and storage, immersion heaters or storage heaters) that will meet the annual thermal demand of each inhabitant
2. The quantity of wind farm generation that can be dispatched to the “virtual heat network”, and its associated values at rates at or below the previous heating price.
3. The capital costs associated with (1), and decommissioning the existing plant.
4. The environmental co-benefits of switching away from non-renewable heating sources.

Exogenous Variables of Interest

EVs uptake. EVs might also provide a distributed electrical storage network as or more cheaply than distributed thermal storage; this will be investigated.

RES to Distributed Smart Heating

Model Parameter	Data Source
Aggregated hourly electrical demand profile on WF side of interconnector	CAR Household Electrical Use Survey
Aggregated hourly electrical demand profile on other side of interconnector	WPD Data
Domestic thermal demand profiles, and associated diversification factors	EE study on Pathways to high heat pump penetration (CCC)
Wind speed time series	Wind speed data taken from Anemos database and converted to load factors
Cost of diesel grid balancing	Taken from STOR availability auction costs.
Interconnector reinforcement costs and regulations	WPD data; ETI Infrastructure cost calculator
Existing thermal technology upkeep/scrapping costs	ACCESS project, manufacturer cost data, EE team in-house data
Heat pump costs and COP data	
Immersion heater costs	
Hot water tank costs, sizes and U-values	
Heating fuel supply costs	
Carbon prices	Taken from ESME model
EV Uptake and Charging Profile Scenarios	EE ECCo Model

RES to Distributed Smart Heating

The Following Outputs will determine the SV and MV Optimal System Configurations and their Costs

Category	Case Study Instance
Grid Network Reinforcement Cost	Interconnector Cost
Electricity Sales	Electricity exported, and concurrent price
Infrastructure Capex	Domestic heating systems cost
Carbon Emissions	Carbon emissions associated with gas , oil and electrical consumption
Carbon Price	Price of above

	MV Solution
Incurred Costs	Immersion heater or HP capex
Avoided Costs	HV network reinforcement, wind farm curtailment costs

Qualitative Benefits

As with previous schemes, RES to Distributed Smart Heating also allows increased renewable uptake, though this will not be quantitively assessed until WP4.

Energy from Waste: Electricity or Gas

Case Description

The diagnostic question in this case study is whether energy from waste (EfW) systems could benefit from flexing their production between gas and electricity in response to price signals.

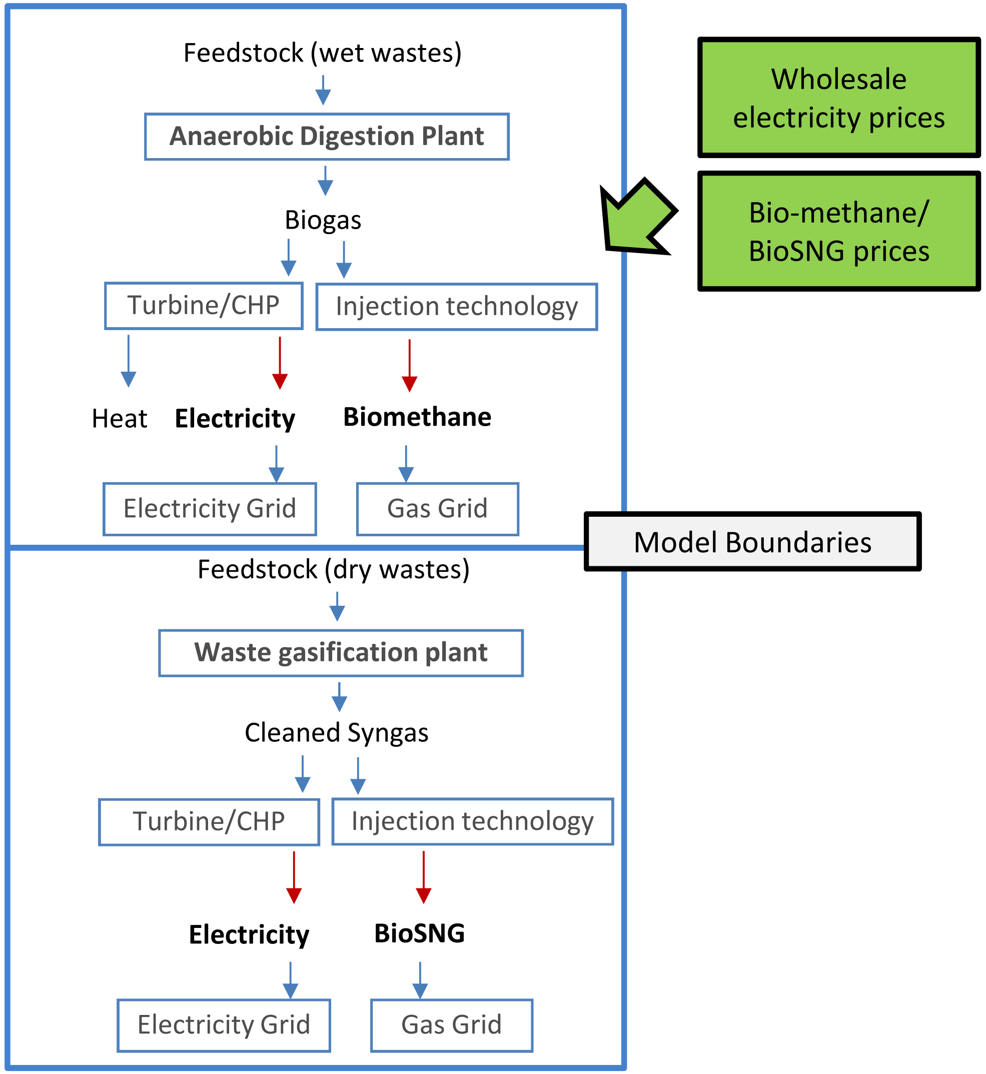
The following scenario will be studied for a snapshot year in the future (e.g. 2050):

- Two different EfW systems: Anaerobic Digestion (AD) and gasification producing biogas and syngas respectively
- SV cases: 1) an AD system and 2) a waste gasification plant are used for power (or CHP) generation
- MV cases: Being equipped with suitable additional technologies, 1) the AD system can switch to bio-methane production and 2) the gasification plant can switch to the production of BioSNG, both for gas grid injection
- Systems respond to electricity vs gas price signals, capturing the revenues from gas injection into the grid when electricity prices reach very low levels (world of high wind penetration).

Model Boundary

The key inputs in the model are the following:

- Hourly wholesale electricity prices for a UK capacity mix dominated by renewables (Clockwork/Patchwork models)
- Bio-methane/bioSNG prices (assumed to be costed at gas wholesale prices less the carbon price)



Energy from Waste: Electricity or Gas

Model Description

For given wholesale electricity and gas profiles, the model will work out the **costs and revenues of the EfW plants for the asset owner/develope**r in the SV and MV cases:

- In the MV cases, where the installation of additional technologies is required for the ability to upgrade the plant's output to bio-methane or bioSNG and to inject it into the gas grid, the additional investment and operational costs will be included to understand the attractiveness of such a multi-vector system for asset owners.
- Carbon costs and emissions will also be compared in the different scenarios.

SV Optimisation-Case 1

The **AD plant** operates in **electricity or CHP mode;** producing biogas which then supplies a biogas turbine or CHP plant.

Revenues are from wholesale electricity sales only and there is no flexibility to respond to price signals.

SV Optimisation-Case 2

The **waste gasification** plant operates in **electricity or CHP** mode producing syngas which then supplies a syngas turbine or CHP plant.

Revenues are from wholesale electricity sales only and there is no flexibility to respond to price signals.

MV Optimisation-Case 1

The **AD plant** is able to flex its operation based on electricity vs gas prices.

When wholesale electricity prices are sufficiently low (due to e.g. high renewables generation), the plant uses its gas clean-up facility to upgrade the biogas it produces to **bio-methane for injection into the gas grid**.

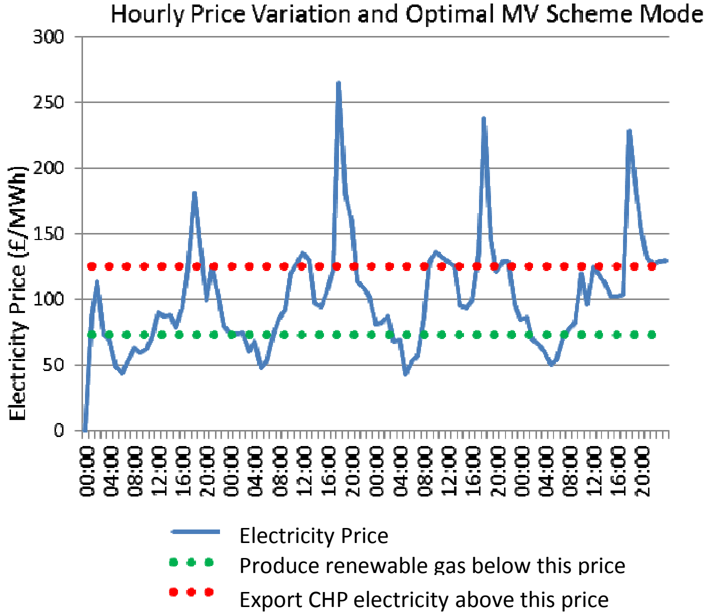
MV Optimisation-Case 2

The waste gasification plant is able to flex its operation based on electricity vs gas prices.

When wholesale electricity prices are sufficiently low (due to e.g. high renewables generation), the plant uses its gas clean-up facility to upgrade the syngas it produces to **bio-SNG for injection into the gas grid**.

Energy from Waste: Electricity or Gas

Model Parameter	Data Source
Investment (capital) costs, fixed and variable O&M costs per technology	ESME model database and publicly available data
Wholesale power prices	PLEXOS dispatch model using ESME results
Technical characteristics per technology type	ESME model database and publicly available data
Wholesale gas prices	ESME model output (shadow price)
Carbon emissions per technology	ESME model database



Energy from Waste: Electricity or Gas

The Following Outputs will determine the SV and MV Optimal System Configurations and their costs

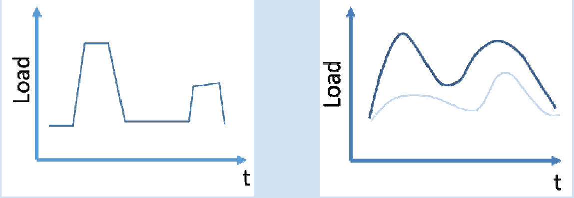
Category	Case Study Instance
Electricity generation costs (£m)	Annualised investment costs
	Fixed & Variable O&M costs
Bio-methane/bioSNG generation costs (£m)	Annualised investment costs
	Fixed & Variable O&M costs
Revenues from electricity sales (£m)	Revenues from selling electricity produced by either AD or waste gasification at wholesale electricity prices
Revenues from renewable gas sales (£m)	Revenues from selling renewable gas (bio-methane/bioSNG) produced by either AD or waste gasification at wholesale electricity prices
Carbon costs(£m) and emissions	Carbon costs borne by the asset owner and carbon emissions in each SV and MV case.

	MV Solution
Incurred Costs	Capital & operational costs (upgrade and injection facilities)
Avoided Costs	Reduced revenues

In the next task we will combine quantitative analysis of multi-vector configurations and a consultative approach to understanding operational implications

T3a: Network Analysis

- Develop demand profiles and assess sizing of technologies / networks in multi-vector & single vector configurations



- Network modelling / simulation to assess key operating parameters
- Use modelling tools – Simone (gas), Sincal (electricity), in-house DH models etc. – and team design / analysis experience

- Capacity and operational parameters pass to T4 to underpin costing and benefit analysis

T3b: Operational / engineering analysis

- Detailed assessment of the operational implications of the multi-vector operating regimes
- Draft analytical framework:

Dimensions to assess	Identify issues	Severity of impact	Potential solutions	Changes / innovation required
Technical issues				
Management / coordination				
Commercial / market				
Regulatory				

Assess operational implications of each multi-vector mode

- Operational and engineering analysis will draw on:
    - experience of the Core & SME teams
    - Additional consultation with industry experts

We have selected two initial cases for the T3 assessment. These will be the subject of discussion at the Stage Gate Review

D3.1a – Initial local case assessment report

- The D3.1a report will be produced at the mid-point of Task 3, prior to the Stage Gate Review, which is planned for mid-October 2016.
- The D3.1a report will include a full analysis of at least one Case Study, including both the case study modelling and analysis in T3.1 and the assessment of engineering and operational implications of the multi-vector configuration in Task 3.2.
- It was further agreed at the Task 2 Case Study Definition Workshop (D2.2), held on 2nd August that it would be beneficial if a further case were also developed to an advanced stage by the mid-term review, to ensure the Steering Group has enough evidence to make an assessment of the project's progress and outputs that are being delivered.
- In response, the team propose to begin the T3 analysis focussing in the following two cases:
  1. Electric heat pumps with gas boilers to meet peak heat demands in individual homes
  2. RES to Hydrogen (Transmission Level) – initially focussing on the case of H2 blending into the national transmission system
- These two cases have been selected as the address multi-vector interactions at opposite scales of the energy system, one focussed on local distribution systems and the other a transmission-scale RES balancing issue.

Appendix

Acronyms

AD – Anaerobic Digestion
BAU – Business as usual
BEV- Battery Electric Vehicle
CBA – Cost Benefit Analysis
CCC - Committee for Climate Change
CCS – Carbon Capture and Storage
CHP – Combined Heat and Power
CO$_2$e - Carbon Dioxide equivalent
COP – Coefficient of performance
DC – Direct current
DECC - Department of Energy and Climate Change
DfT - Department for Transport
DH – District Heat
DNO/DSO – Distribution network operator/ Distribution system operator
DSM – Demand Side Management
DUoS – Distributed Use of System
EE - Element Energy
EHP – Electric Heat Pump
ETI - Energy Technologies Institute
EV – Electric Vehicle
FCV – Fuel Cell Vehicle
GSP – Grid Supply Point
HGV - Heavy Goods Vehicle
HP – Heat Pump
HV – High voltage
HW – Hot water
ICE – Internal Combustion Engine
KE – Kinetic energy
LCOE – Levelised cost of energy
LV – Low voltage
MV – Multi-vector
P2G – Power to Gas
PHEV – Plug-in Hybrid Electric Vehicle
PPA – Power purchase agreement
PRS – Pressure reduction station
Repex – Replacement expenditure
RES – Renewable Energy Source
RfP - Request for Proposal
SGF – Smart Grid Forum
SMR – Steam Methane Reformer
SV – Single vector
UCL - University College London
V2G – Vehicle to Grid
WF – Wind Farm