Programme Area: Energy Storage and Distribution

Project: Storage & Flexibility Modelling

Title: Storage and Flexibility Model Final project report

Abstract:

The Storage and Flexibility Model is an AIMMS based model that provides a framework to allow techno-economic analysis of the role of storage and other means of energy system flexibility across multiple energy vectors at multiple levels of the energy system. This deliverable provides the project final report which summarises:

- Scenario analysis using the modelling framework and data developed during the project
- Identification and assessment of 3 case-study examples of private sector storage investment and potential generic policy options
- Wider qualitative assessment of risks/opportunities for storage deployment associated with the analysis undertaken
- The report will also describe how the scenarios have been constructed and describe the underlying model framework insofar as it is necessary to support the interpretation of its outputs.

Context:

This project will develop energy system modelling capability to increase understanding of the role of energy storage and system flexibility in the future energy system. The modelling capability will provide a whole systems view of the different services that could be provided and at which points in the energy system they are most appropriate. Management consultancy Baringa Partners are delivering this new project to develop the capability to improve understanding with regards the future role of energy storage and the provision of cross-vector system flexibility within the context of the overall UK energy system.

D2.4 Storage and Flexibility Model Final project report

CLIENT: Energy Technologies Institute

DATE: 16/10/2018

Version History

Version	Date	Description	Prepared by	Approved by
1.0	20/12/2017	Final report for review by ETI and Members	LH / RN / JG	OR
2.0a	03/06/2018	Partial update for ETI review	LH / RN / JG	JG
2.0b	26/06/2018	Full update for ETI review	LH / RN / JG	JG
3.0	11/09/2018	ETI comments addressed	LH / JG	JG
4.0	03/10/2018	Final version	LH	JG

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Executive Summary

Introduction

The primary objective of the Energy Technology Institute's (ETI) Storage and Flexibility Modelling (SFM) project is to develop the capability to improve understanding of the future role of energy storage and the provision of system flexibility within the context of the overall energy system. This aims to provide a techno-economic evaluation of energy storage and other sources of flexibility across multiple:

- **Energy vectors**: electricity, heat, gas, hydrogen
- **Points in the energy system**: transmission level, distribution level, behind-the-meter (industry, commercial, domestic)
- **Geographic regions**: full representation of the GB energy network topology, through regional nodes (11 onshore and 12 offshore) and inter-regional transmission links
- **Timeframes**: for example, technical '**system services**' across different timescales (sub-hourly through to multiple hours) which are needed to operate the system such as frequency containment and reserve replacement; along with wider '**system benefits**' such as peak shaving and avoiding renewables curtailment, which help to reduce the overall costs of the energy system

The project has been split into two stages:

- **Stage 1:** Reviewed the requirements for flexibility across the energy system and the high level design for the new modelling framework. This stage also reviewed other energy system models and identified that the SFM can help to fill a key gap related to combining insights from long-term whole systems modelling with a truly multi-vector view of operational dispatch.
- **Stage 2:** Developed the first release of the SFM model and demonstrated how the methodology can provide valuable insights, via analysis of two scenarios.

Overview of modelling framework

The complexity of the issue to be modelled means that it is intractable to represent this in a single optimisation problem. Instead, the SFM consists of two hard-linked optimisation modules:

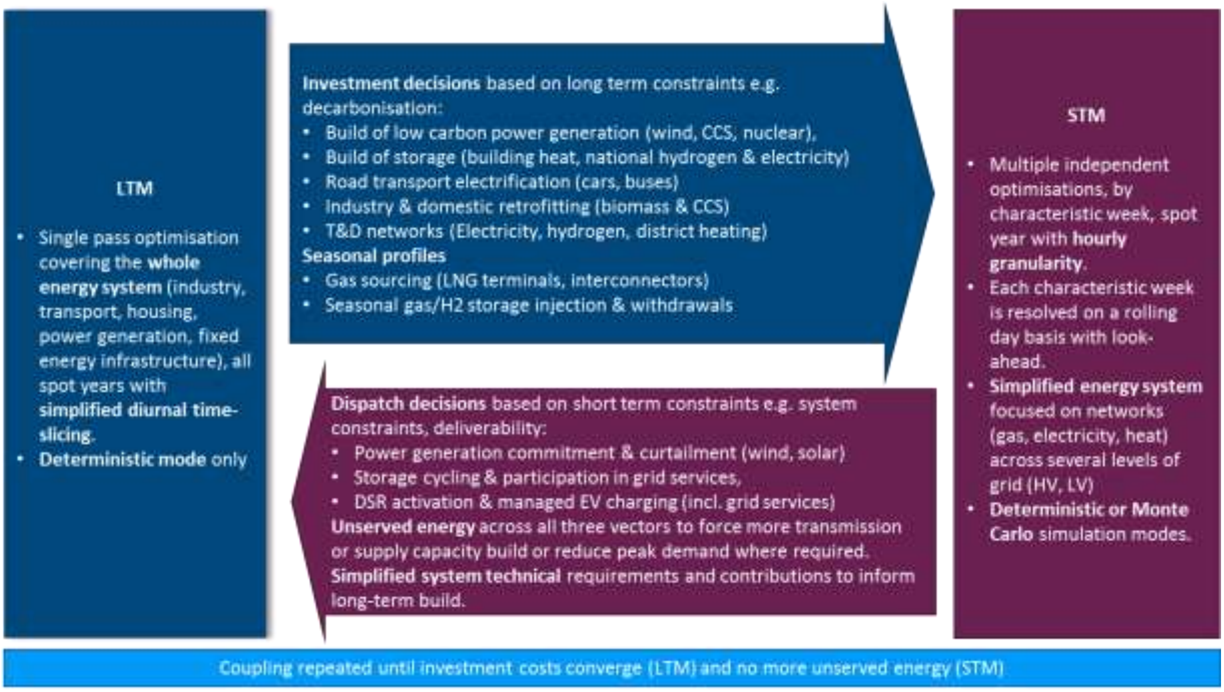
- Long Term Module (LTM), which is an enhanced version of the ETI's Energy Modelling System Environment (ESME) v4.1 model[1] covering both long-term capacity expansion and simplified operation of the system. Key enhancements for this project have included:

[1] ESME is a strategic energy system planning tool, developed by the Energy Technology Institute (ETI). ESME provides decarbonisation pathways using a policy neutral cost optimisation methodology. ESME is used by a range of ETI members from the private and public sector and has been internationally peer reviewed. http://www.eti.co.uk/programmes/strategy/esme

- Explicit representation of the gas network and storage technologies, along with additional multi-vector conversion routes such as Power to Synthetic Natural Gas
  - A broader range of storage technologies across heat and electricity
  - Updated representation of peak capacity requirements and system services for frequency (containment / replacement) and reserve
  - More granular, archetypal representation of electricity distribution networks and the technologies connected to these; differentiating rural/urban and high/low voltage
- Short Term Module (STM), a bespoke extension for this project, focused on the detailed operation of the system only (i.e. without consideration of capacity expansion).
  - This provides detailed hourly operation of the integrated energy system for electricity (reflecting e.g. unit commitment and other dynamic constraints on operation such as ramp rates), gas, hydrogen and heat across a number of characteristic weeks, including proxies of operation for sub-hourly system service requirements.
  - In addition to a detailed view of supply-side flexibility both within and between energy vectors, the STM provides a detailed representation of demand-side flexibility across electric vehicles, heat storage, industrial demand side response and use of electrolysers.

The SFM iterates between these modules passing information from one to the other (i.e. at high level the LTM frames the long-term system and the STM helps it to understand what the detailed operation of the system would look like) until a stable equilibrium is reached based on user-defined stopping criteria. These broadly represent a limited change in the LTM system design between iterations and negligible unserved energy when operating this system in the STM. The STM can be run in either a deterministic mode (with a dedicated peak week alongside four characteristic seasonal weeks) or a Monte Carlo mode whereby key operational drivers such as wind, solar and temperature profiles, interconnector prices and unplanned outages are simulated (across the four characteristic seasonal weeks).

Figure 1 Overview of Storage and Flexibility Model



Scenario analysis

As part of helping to demonstrate a working release 1.0 of the SFM and to illustrate the types of insights that this modelling framework can provide going forwards, two deterministic scenarios have been explored:

- The **Base Scenario** represents a central view of all key parameters and takes many of its assumptions from the ESME v4.1 Reference model upon which the LTM was based. Further data has been added for the LTM additions mentioned above, as well as supplementary information needed for the STM (e.g. shaping profiles to convert aggregate heat service demands or wind/solar outputs to an hourly granularity)

The **No CCS Scenario** represents a form of "stress test", as previous experience (e.g. using ESME) shows that without this technology the energy system is materially harder to decarbonise. This, for example, leads to greater deployment of intermittent renewables and correspondingly greater system flexibility and Reserve requirements.

Additionally, short term uncertainty has been analysed in in terms of its impact on capacity build in 2050:

- The **Monte-Carlo** run uses long term assumptions consistent with the Base scenario, but with short term uncertainties represented by 20 independent simulations in of the STM. These uncertainties include: wind and solar output, plant outages, electricity interconnector import prices, temperature. For the Monte-Carlo capacity decisions up to 2040 are fixed to match the Base scenario solution, but decisions in the final time period, 2050, are optimised based on the information from the Monte-Carlo STM simulation.

Considering the research questions that this project has designed a tool to answer, the following insights have been found:

- **What is the future role of energy storage in the energy system considering flexibility within and across multiple vectors, points in the system and services?**
  - The requirement for storage capacity is likely to increase substantially by 2050 (potentially 270GW of heat storage and 80GW of electricity storage in the Base scenario)
    - In the heat sector, building level heat storage can provide an immediate benefit to the system, primarily due to providing peak load capacity
    - In the electricity sector there is less need for storage until 2050, where the need increases considerable due to decarbonisation targets reducing flexible generation and increasing peak supply
    - In the gas sector there is likely to be sufficient capacity in existing storage, with no new build storage required as gas demand gradually decreases
  - The primary use for storage in 2050 is peak load reduction, rather than provision of system services (though storage does provide the bulk of these services)
  - Heat storage is critical to decarbonising the heat sector through electrification, while decoupling the electricity system from the large swings in demand from the heat sector
  - The key storage technology in the electricity sector is likely to be grid scale Pumped Heat, however home level battery storage is also valued due to its ability to reduce peak demand at all grid levels
  - The need for storage is related to the availability of other forms of flexibility
    - When flexible CCGT with CCS technologies are removed in the No CCS scenario the need for storage increases in all sectors
    - Where electric vehicles operate under managed charging this can be used to balance electrified heat, thus reducing the requirement for flexible dedicated storage technologies
- **What is the scale of the different future service requirements (e.g. in MW, MWh) and how do interactions across multiple parts of the energy system influence these?**
  - Reserve requirements are likely to increase substantially (to 30GW in the No CCS scenario), due to increases in electricity demand (from electrification of heat and transport), and wind and solar generation (decarbonisation of electricity sector)
  - Frequency service requirements are likely to decrease, as high inertia nuclear generation dominates decarbonised electricity supply
- **What is the value of various forms of storage to the system, both in the most immediate part of the system and indirectly to wider parts of the system, e.g. through multi-vector interactions?**

- The most valuable service that storage can provide is in providing peak load capacity, and displacing other supply or network reinforcement
- Both Reserve and Frequency services can be provided by flexible capacity built primarily to meet peak load, with little value in providing these services
- Building level heat storage is one of the most valuable storage technologies, providing behind the meter peak load reduction that has an impact on load at all grid levels and across multiple energy vectors

- **How do the key drivers of uncertainty (both short- and long-term) affect the potential role of storage and the competing alternatives?**
  - Materially higher volumes of storage will be required if CCS technologies fail to materialise, 28GW additional heat storage and 75GW additional electricity storage, plus additional flexibility from EVs with managed charging
  - Where flexible CCGT with CCS technologies are not available the system has a greater need for highly flexible short duration storage technologies (Li-Ion batteries) rather than longer duration storage technologies (Pumped Heat)
  - Where short term uncertainty is included through Monte-Carlo simulation, the SFM designs a system that is more resilient to a range of operating conditions
    - A more diversified capacity mix, increased in total capacity
    - Increased capacity and utilisation of hybrid technologies (eg MicroCHP) which prove suitable for a range of conditions
  - The Monte-Carlo runs show the risk of using a single set of operating conditions when designing a system: in this case the Base scenario undervalues the role of wind generation

- In the Monte-Carlo runs wind capacity is increased, reducing CCGT with CCS capacity and increasing flexible electrical storage capacity

Drivers of value for private investment

Using results from the overall system analysis, three illustrative storage case studies have been explored from a private investor perspective - using a proxy Discounted Cashflow (DCF) analysis on the Base Scenario results - to help understand:

- Where and to what extent the value for these technologies materialises across the system (e.g. managing peak, providing broader system flexibility or more explicit provision of technical system services)
- To what extent increased private investment risks (necessitating a higher hurdle rate) can be accommodated given the implied system value from the Base Scenario results.

The case studies covered building-scale heat storage, a home building-scale Li-ion battery and a large-scale pumped heat electricity storage site.

- In all cases, the most material value drivers stemmed from provision of peak capacity and to a lesser extent avoided distribution network reinforcement across the pathway.

- Energy arbitrage revenues played only a modest role in the medium term, but grew significantly by 2050 given, for example, the expansion of intermittent generation on the system.
- Building heat storage and pumped heat electricity storage still showed positive returns with hurdle rates above the default 8% assumed in the LTM (consistent with ESME)
- This was not the case for the Home Li-Ion battery, which implies that this is (or is close to being) the marginal cost technology from the overall system's perspective.

Areas for further work

The project has both scoped and developed a working "Release 1.1" SFM model and demonstrated the value of including a temporally detailed multi-vector analysis of system operation along-side the traditional whole system view of long-term capacity expansion (with a more limited operational view). The project has outlined several possible areas for further work including further enhancements to the scope of the model (such as inclusion of voltage-related constraints, subject to good data availability). However, the highest priority is related to non-reproducibility (actively being worked on by AIMMS) and performance improvements to facilitate more rapid convergence of the solution. Performance improvements can be driven by both code direct performance (e.g. mass-parallelisation of STM optimisations is possible) as well as more heuristics to help steer the solution to its expected convergence point more rapidly.

Glossary

Term	Description
Demand side response	Any source of energy demand that can be shifted (in time) or "shedded" (ie lowered by reducing activity or by using an alternative energy supply), typically in response to price signals and/or requests from a central system operator
Energy service	The technical needs of an energy system, over and above energy balancing (usually dealt with through wholesale markets). Examples of energy services include reserve and frequency response in the electricity sector.
ESME	Energy Systems Modelling Environment, a peer reviewed whole energy system planning model developed by Redpoint/Baringa for the ETI
Flexibility	The ability of energy supply, storage and demand technologies to change their output / consumption level quickly, typically in response to intermittency in supply/demand elsewhere in the system
Look-ahead	A part of the modelling horizon that is beyond period of interest for the optimisation step but is included when performing optimisation, the results for the look-ahead period then being discarded (ie 24h + 6h lookahead uses a horizon of 30 hours for each optimisation step but only keeps results from the first 24 hours before moving to the next 24h period)
Module	Self-contained part of a model that can be run independently of other modules, though may be linked to other modules though its inputs and outputs
Objective Function	In a linear programming optimisation this is the function that is to be minimised or maximised. For the SFM the objective function is to minimise total system costs, including capex of new technologies and all fixed and variable costs of energy production
Peak reserve margin	Measure of how the energy production and transfer capacity of a particular point of the energy system should be changed to ensure capacity is close to the demand requirements. A peak reserve margin >1 implies that there is unserved energy and capacity must increase. A peak reserve margin <1 implies that there is over-capacity.
Peak contribution factor	The proportion of the installed capacity of a supply technology that is used in peak periods, used to calculate how effective a technology is at reducing unserved energy.
Timeslice	Temporal granularity of model. The SFM represents a day using either 24 x 1hour timeslices (STM), or less precisely using 5x blockier timeslices (LTM).
Unserved Energy	Any underlying consumer demand for energy not met by the model. A small amount of unserved energy may be acceptable in some circumstances (ie in peak Winter periods domestic heating technologies may not quite meet the typical comfort level temperature).
Value Driver	Any feature of a technology that provides "value" to the system as a whole – in the SFM this refers the ability of a technology to lower overall system costs (value drivers could be: the ability to provide low cost energy, provide energy services at low cost, avoid the need for increased capacity elsewhere in the system)

List of key acronyms

Acronym	Description
AIMMS	Advanced Integrated Multidimensional Modelling Software
ASHP	Air Source Heat Pump
BEV	Battery Electric Vehicle
BSUoS	Balancing Services Use of System (charges)
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture & Storage
CHP	Combined Heat & Power (plant)
CM	Capacity Market
CO2	Carbon Dioxide
CVEI	Consumer Vehicles and Energy Integration (project)
DCF	Discounted Cash Flow
DECC	Department of Energy & Climate Change
DNO	Distribution Network Operator
DSR	Demand Side Response
DUoS	Distribution Use of System (charges)
EHV	Extra-High Voltage
ENA	Energy Networks Association
ESME	Energy Systems Modelling Environment
ETI	Energy Technologies Institute
EV	Electric Vehicle
GB	Great Britain
GDP	Gross Domestic Product
H2	Hydrogen
HV	High Voltage
ICE	Internal Combustion Engine
kW	Kilowatt
LCoE	Levelised Cost of Energy
LDN	Local Distribution Network
LED	Light Emitting Diode
LT	Long Term
LTM	Long Term Module (for investment decisions)
LV	Low Voltage
MARKAL	MARKet ALlocation (model)
MC	Monte Carlo
MIP	Mixed Integer Program
MSL	Minimum Stable Level
MT	Medium Term
MW	Megawatt

MWh	Megawatt hour
NTS	National Transmission System
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas & Electricity Markets (regulator)
OPEX	Operational Expenditure
PCF	Peak Contribution Factor
PHEV	Plug-in Hybrid Electric Vehicles
PRM	Peak Reserve Margin
PV	Solar photovoltaic
ROCOF	Rate of Change of Frequency
SFM	Storage and Flexibility Model
SMR	Small Modular Reactor
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
SO	System Operator
SOF	System Operability Framework
SQL	Structured Query Language
ST	Short Term
STM	Short Term Module (for operational decisions)
TIMES	The Integrated MARKAL-EFOM System
TNUoS	Transmission Network Use of System (charges)
TWh	Terawatt hours
UK	United Kingdom
VST	Very Short Term
WeSIM	Whole electricity System Investment Mode
WESM	Whole Energy System Model

1 Introduction

1.1 Background

The primary objective of the Energy Technology Institute's (ETI) *Storage and Flexibility Modelling* project is to develop the capability to improve understanding of the future role of energy storage and the provision of system flexibility within the context of the overall energy system. This aims to provide a techno-economic evaluation of energy storage and other sources of flexibility across multiple energy vectors (electricity, heat, gas and hydrogen) accounting for the different services that could be provided (e.g. frequency response, avoiding wind curtailment, peak load reduction, etc) and at which points in the energy system (transmission, distribution, building level) and geographic location with Great Britain they are most appropriate.

The ETI engaged Baringa Partners LLP (Baringa) to design, build and use the Storage and Flexibility Model. This report describes the final outputs of the project; primarily the model design and the insights gained from analysing the GB energy system using it.

The project has been split into two stages:

- **Stage 1**
  - Investigated the key services and technologies that should be included to sufficiently model the role storage could provide to the energy system
    - Analysis published by the ETI and available in ETI Knowledge Zone website[2]
  - Analysed the near term (5-10 years) potential for storage technologies within the current GB energy system
  - Provided a draft high level design for whole system modelling framework that allows the role of storage and other flexible technologies to be studied over the long term (~40 years)
    - Analysis published by the ETI and available in ETI Knowledge Zone website[3]
- **Stage 2**
  - Stage 2a
    - Investigated sources of data required for proposed long term modelling framework
    - Provided prototype model to test key methodologies
  - Stage 2b
    - Completed whole system model to allow long term role of storage to be studied

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[2] http://www.eti.co.uk/programmes/energy-storage-distribution#search-block, search for "Energy Storage Mapping Report"

[3] http://www.eti.co.uk/programmes/energy-storage-distribution#search-block, search for "Stage 1 Final Report"

- Provided analysis of the potential role for storage and other flexible technologies to the GB energy system
- Investigated private investment cases for storage, giving qualitative description of risks to storage and how these may be mitigated.

The focus of this report is *Stage 2b* of the project, which is comprised of 5 deliverables:

- **D2.3.1 – v1.0 Model Framework**
  - First full release of Storage and Flexibility Model
- **D2.3.2 – Final Assumptions Book**
  - Description of final data used to populate the v1.0 model, with description of source and purpose of all new data used in this project
- **D2.3.3 – Training Material**
  - Collation of informal training material generated as part of this project and through working with ETI lead analyst
- **D2.4 – Final Project Report *(this document)***
  - Summarises the analysis and findings of this project, including scenario analysis to 2050, private investment case studies, and a qualitative assessment of risks to storage deployment
- **D2.5 – ESME Update part 2**
  - Updates to the core ESME code to incorporate some additional functionality from this project into ESME model (representation of electricity local distribution networks (LDNs) and their reinforcement costs, representation of gas network, and electricity system service constraints)

1.2 Purpose of this report

The purpose of this report is to describe the outputs of the analysis carried out using the model (D2.3.1) and assumptions (D2.3.2) developed as part of this project. The scope of the project is to develop a modelling framework capable of studying investment decision pathways to heavily decarbonise the GB energy system by 2050, giving appropriate representation to storage and other flexible technologies. The potential role of storage and other flexible technologies is studied through scenario analysis, Monte-Carlo analysis, private investment case studies, and a qualitative assessment of the risks to storage deployment.

This report aims to be stand-alone and may be understood by a reader who is familiar with the GB energy system and whole system modelling approaches but has not read the previous project deliverables. Previous deliverables (notably D1.1-1.3, and D2.1.2[4]) have described the complexity of modelling the value of storage and have outlined the modelling approach taken in this project in

[4] D1.1 - Energy Storage Mapping Report
D1.2 - Assessment of the near term market potential for energy storage
D1.3 - Approach for modelling long term role of energy storage
D2.1.2 - Prototyping summary presentation

some detail. This report gives a high level summary of the modelling approach and uses initial results from the tool to describe the range of potential insights the tool is capable of providing.

1.3 Structure of the report

- Section 2 describes the final modelling framework developed within this project, including the main areas of complexity and the simplifications taken to reduce the total model complexity.
- Section 3 describes the core scenario analysis, including investment and operation decisions in the Base Scenario and two alternate scenarios, and monte-carlo analysis
- Section 4 explores the key drivers of value that might materialise to facilitate private investment in storage, within three different technology examples, and whether these are sufficient given additional investment risks
- Section 5 describes overall conclusions and recommendations as a result of the analysis performed during this project

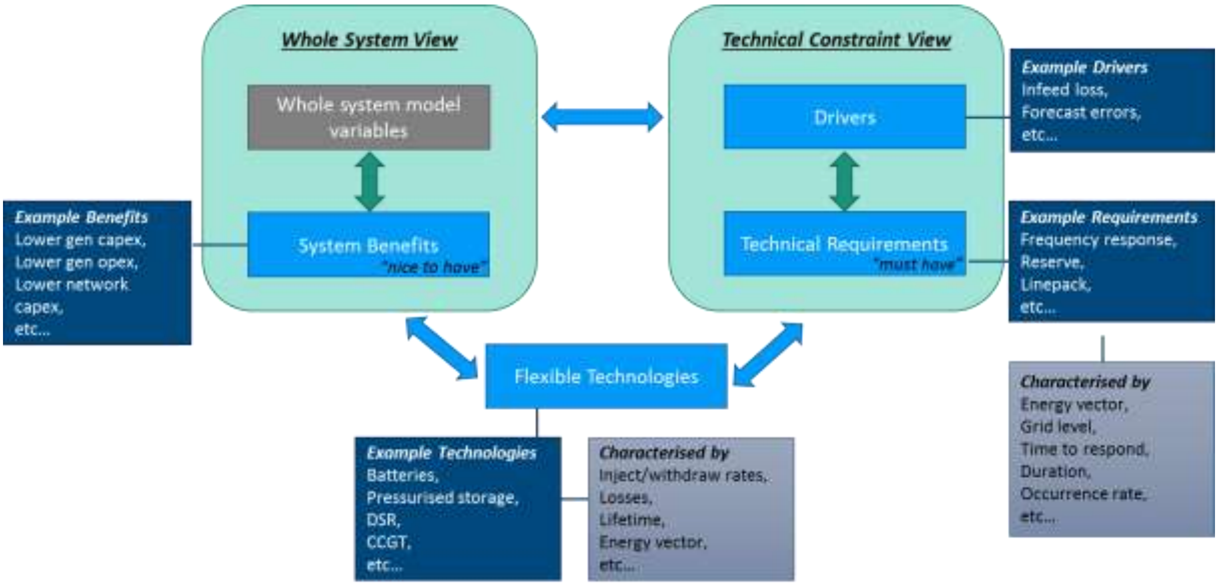
2 Modelling framework

2.1 Design requirements

There already exists a sizeable volume of work from academia and industry (summarised in project deliverable D1.3) looking at the role of energy storage in specific cases e.g. electricity storage for energy arbitrage or seasonal gas storage for security of supply. However, a key gap is a more holistic techno-economic analysis of the role of storage across ***multiple***:

- **Energy vectors**: electricity, heat, gas, hydrogen
- **Points in the energy system**: transmission level, distribution level, behind-the-meter (industry, commercial, domestic)
- **Timeframes**: for example technical '**system services**' across different timescales (sub-hourly through to multiple hours) which are needed to operate the system, such as frequency containment and reserve replacement; along with wider '**system benefits**' such as peak shaving and avoiding renewables curtailment, which help to reduce the overall costs of the energy system as illustrated conceptually in Figure 2.

Figure 2 Modelling characterisation of system benefits versus technical requirements



The Storage and Flexibility Model (SFM) seeks to cover all the above in a Whole Energy System Model (WESM) of the GB energy system.

2.1.1 Key research questions

The scope of the SFM modelling framework is very wide, but there are some key research questions that the SFM has been designed to answer. These are listed in Table 1, along with the relevant sections of this report where each research question is addressed.

Table 1 Key Research questions

Research Question	Section(s) addressed in
What is the future role of energy storage in the energy system considering flexibility within and across multiple vectors, points in the system and services?	*3.3*
What is the scale of the different future service requirements (e.g. in MW, MWh) and how do interactions across multiple parts of the energy system influence these?	*3.3*
What is the value of various forms of storage to the system, both in the most immediate part of the system and indirectly to wider parts of the system, e.g. through multi-vector interactions?	*3.3*
How do the key drivers of uncertainty (both short- and long-term) affect the potential role of storage and the competing alternatives?	*3.3, 3.4*
What are the key drivers of value that might materialise to facilitate private investment in storage for different technologies and are these sufficient given additional investment risks?	*4*
What new services or business models might emerge as part of maximising the value of storage from private investor's perspective?	*4.6*

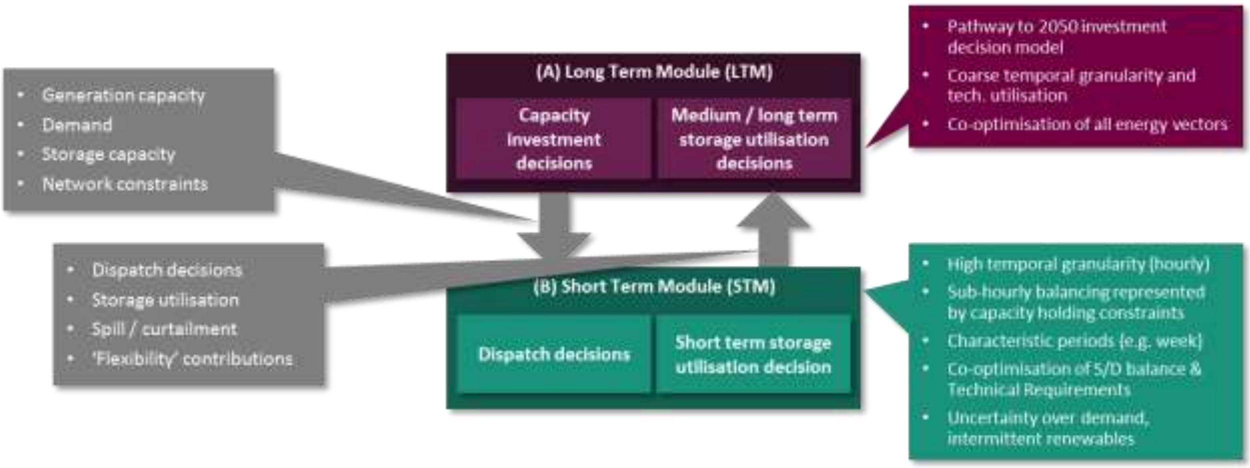
2.2 High level design

A key finding of the literature review (D1.3) is that to accurately value the role of storage both long term investment and short-term dispatch decisions must be taken into account. Due to model run times it is not tractable to combine a long-term horizon (decades) with the short-term granularity (hourly) required, at least not in a single optimisation problem covering the full energy system.

The SFM separates the problem using two hard-linked modules, as shown in Figure 3:

- Long Term Module (LTM)
  - Investment decisions to 2050
  - Optimised for least cost (covering CAPEX, OPEX and resource costs)
  - Multi energy vector co-optimisation
- Short Term Module (STM)
  - Dispatch decisions at hourly granularity
  - Sub-hourly balancing represented by capacity holding constraints
  - Optimised for least cost (covering variable OPEX and resource costs only)
  - Multi energy vector co-optimisation focused on electricity, gas, heat and hydrogen

Figure 3 High level design



Both the LTM and STM use the same high level paradigm, assuming a central planner optimising the solution for least cost of the system as a whole. Both modules produce results that are in general policy neutral, though in some cases the representation of the system assumes certain policy frameworks continue (in particular policies relating to security standards and safe operation of the system).

In the following subsections, the technical modelling environment and key modules are introduced, with more detail of the level of complexity in each area of the model given in Section 2.2.6.

2.2.1 Long Term Module

The LTM requirements are similar to the ETI's "Energy Systems Modelling Environment" (ESME), and ESME (v4.1) was the starting point for the development of the LTM.

Energy Systems Modelling Environment (ESME)

ESME is an internationally peer reviewed energy systems model, providing strategic insight of decarbonisation pathways for the UK. ESME was originally developed for ETI's own purposes to identify investment in technology innovation. It has since been used by a range of public and private sector organisations, including the Committee on Climate Change and the Department for Business, Energy and Industrial Strategy.

ESME is a design tool, providing policy-neutral pathways to a decarbonised future energy system. using an optimisation approach. The ESME optimisation finds least-cost energy system designs which meet stipulated sustainability and security targets, whilst taking account of technology operation, peaks in energy demand and UK geography.

The key inputs to ESME include:

- **Technology** costs, operational parameters, build constraints, including retrofit
- Underlying energy **Demands** and their evolution

- **Network** capacities and reinforcement costs and build constraints
- **Resource** costs and availabilities
- **Emissions** targets
- **Security of supply** constraints

The key outputs from ESME include:

- **Technology** capacity evolution and resulting operational profiles
- **Demand** growth/reduction due to technology intervention
- **Network** capacity evolution
- **Resource** use projections
- **Emissions** projections
- **Costs** (both investment and operational) of pathway to optimal system design

This document assumes that the reader has some familiarity with ESME. Further information on ESME is available from the ETI in the form of a high level overview[5] and a more detailed technical description[6].

Building on ESME to produce the LTM

The LTM uses the ESME v4.1 data and modelling framework as the starting point for its development, keeping much of the core ESME formation:

- **Objective function:** minimise total discounted energy system costs over a multi decade pathway
- **Decision variables:** conversion/network/storage technology capacity build, activity and resource use
- **Constraints:** supply/demand balancing, carbon, maximum technology build rate/quantity, maximum resource availability, etc.
- **Temporal resolution**: Spot years are used to cover the long-term horizon, 10 year time periods by default, with characteristic days representing different periods within the year. The SFM LTM keeps the same Winter/Summer characteristic periods as ESME. Diurnal profiles are modelled using coarse granularity blocks (5 per day, of varying length to capture main demand characteristics)
- **Geographical resolution:** The LTM covers the same geographical area as ESME excluding Northern Ireland[7], separated into 23 nodes representing the 11 England and devolved administration political regions and 12 offshore regions.

[5] http://www.eti.co.uk/programmes/strategy/esme
[6] http://www.eti.co.uk/library/modelling-low-carbon-energy-system-designs-with-the-eti-esme-model
[7] Including NI would have required extending the representation within the STM (along with the LTM) to cover the whole of the Irish Single Electricity Market, to more robustly represent the dispatch in Northern Ireland.

- **Uncertainty:** While the LTM retains the option for Monte Carlo analysis of key long-term drivers, like ESME, the run times of the coupled LTM-STM model mean that long term uncertainties are explored through discrete sensitivities.

Enhancements that move the LTM beyond ESME 4.1 functionality include:

- **Gas network:** a simple representation of gas network the National Transmission System (NTS) and Local Distribution Network (LDN) has been included to allow constraints on gas flows to be correctly modelled, both within the model (network constraints) and at the boundary of the model (interconnector and Liquefied Natural Gas resource constraints).
- **Additional conversion technologies:** conversion technologies (i.e. Power to Synthetic Natural Gas) added to model to ensure multi energy vector interactions are correctly represented
- **Additional storage technologies:** storage technologies added to model give wider representation of potential value storage can give to the energy system.
- **Updated peak reserve margin constraint:** reflecting peak supply/demand impacts across the system (multiple vectors and grid levels) with the peak contribution from supply and storage technologies represented as a function of active capacity (informed by results from the STM).
- **Electricity system services:** system services required for a stable electricity system (e.g. frequency containment, reserve replacement) are included using a set of linear constraints that have an endogenous calculation of system service requirements, and contributions from each technology towards each constraint based on operating state.
- **Intra-node electricity network granularity:** The LTM extends ESME to include a fuller representation of the distribution network, capable of representing multiple voltage levels and allowing the physical flow of energy up and down between all network levels and relevant connected technologies. Archetypal LDNs (rural and urban) are used to produce a unique set of LDN reinforcement cost curves at each node, replicating the characteristics of the geographical region that node is representing.
- **High resolution shaping:** post processing steps added to take the outputs from the LTM and make these in the format required for the STM, from coarse granularity diurnal time steps to hourly time steps (e.g. to produce an hourly solar electricity generation profile used in the STM).

A full list of the technologies added to the ESME 4.1 starting model as part of the development of the SFM is given in Appendix B.2.

2.2.2 Short Term Module

The STM is similar in structure to the LTM but has a number of differences; notably in temporal granularity and unit commitment of dispatchable generation. Features that are shared with the LTM include:

- **Geographical resolution:** the STM uses the same nodes as the LTM, and the same intra-node granularity for networks (i.e. gas and electricity LDNs)
- **System services:** includes the same system services as in the LTM, again through a number of linear constraints that endogenously calculate the system requirement and contribution from each technology.

The STM varies from the LTM in the following areas:

- **Objective function:** minimise total variable operating and resource costs over each characteristic week, i.e. each characteristic week is modelled independently, with no investment decisions
- **Temporal resolution:** covers 4 characteristic weeks, one for each season, plus a “peak week” for use in parameterising the security of supply constraints in the LTM.
  - STM time steps are hourly, rather than 5 steps per day in the LTM. The STM solves using rolling daily horizon, from Monday through to Sunday in each characteristic week. In each “daily” step the horizon is 24hours + user definable look-ahead, currently set to 10 hours. This look-ahead period allows the model to have an understanding of conditions in the next day (for example if there is high morning demand a plant may choose to stay on at a loss overnight and avoid start-up costs the next day). However, dispatch decisions covering the look-ahead period are ignored when solving the next daily optimisation step (which overlaps with the look-ahead period from the previous day).
  - Within each daily step the SFM solves with perfect foresight, and with no view of conditions outside of the daily horizon (plus look-ahead). The daily step has been selected for two reasons
    - To reduce run time vs a weekly step size
    - To more accurately represent the information horizon that generators will make their dispatch decisions on (ie a weekly step with perfect foresight will over optimise the dispatch decision)
- **Decision variables:** these are the parameters that the model can adjust when finding the least cost solution
  - Binary on/off unit commitment for electricity plant with high fixed start-up costs. Such plant incurs a high cost when switched on, and to avoid the model avoiding these costs by running at very low load factors (but not switching off) a minimum stable level (MSL) load factor constraint is imposed which forces the plant to commit to being fully off or fully on at a level above this MSL.
  - Supply technology activity (electricity, DSR shedding or shifting, etc.)

- Storage technology injection and withdrawal (noting that for seasonal storage within week flexibility is still bounded by the overarching pattern of seasonal injection or withdrawal from the LTM).
- Spill energy volumes (the amount of excess energy to choose to release from the system without being used to meet demand)

- **Constraints (varying by node and time slice):**
  - Capacity-related constraints (generation, storage, network, interconnectors, DSR load shedding) – e.g. maximum supply technology activity or storage net injection must be ≤ active capacity, or active storage volume, respectively
  - Dynamic electricity constraints (e.g. min on/off times, min stable generation, max ramp up/down rates)
  - DSR-related constraints reflecting: industrial load shedding, managed charging of EVs, flexible use of hydrogen electrolysers and electrified heat load shifting through the use of storage
  - Individual constraints for each of the system services used to keep the system stable
- **Uncertainty:** Variation in demand, renewable generation, plant availability and price of resources in interconnected markets assessed through a monte-carlo generator and analysis
- **Technologies:** the STM aggregates some technologies from the LTM to ensure reasonable run times subject to user-defined choices[8]. The STM is also focused primarily on aspects of the system that are materially impacted by hourly operational decisions; electricity, heat, gas and hydrogen. As a result, it is not necessary to model some of the LTM technologies explicitly in the STM. For example, a fossil liquid fuel-only car has no bearing on the operational decisions in the STM, whereas it is important to represent dynamically the charging associated with electric vehicles given their knock-on implications for the electricity system.

2.2.3 Coupling the modules

To make the problem tractable the modules are separated and run sequentially one after another. The modules are coupled through the information passed from one module to another at the end of each run, as shown in Figure 4. This helps to ensure that the insights generated by the STM with much level of operational granularity are reflected within the LTM's decision making.

The STM takes capacities of supply, storage and demand technologies from the LTM and operates the resulting system at high granularity. "Shaping" profiles are used to convert the coarse granularity demand and fixed generation profiles in the LTM into the high granularity profiles in the STM. A number of different approaches are used to derive these shaping profiles, using a range of data sources[9]. The detail of how the sources are used to produce the detailed shaping profiles for the STM is described in D2.3.2 (Final Assumptions Book and supporting documents).

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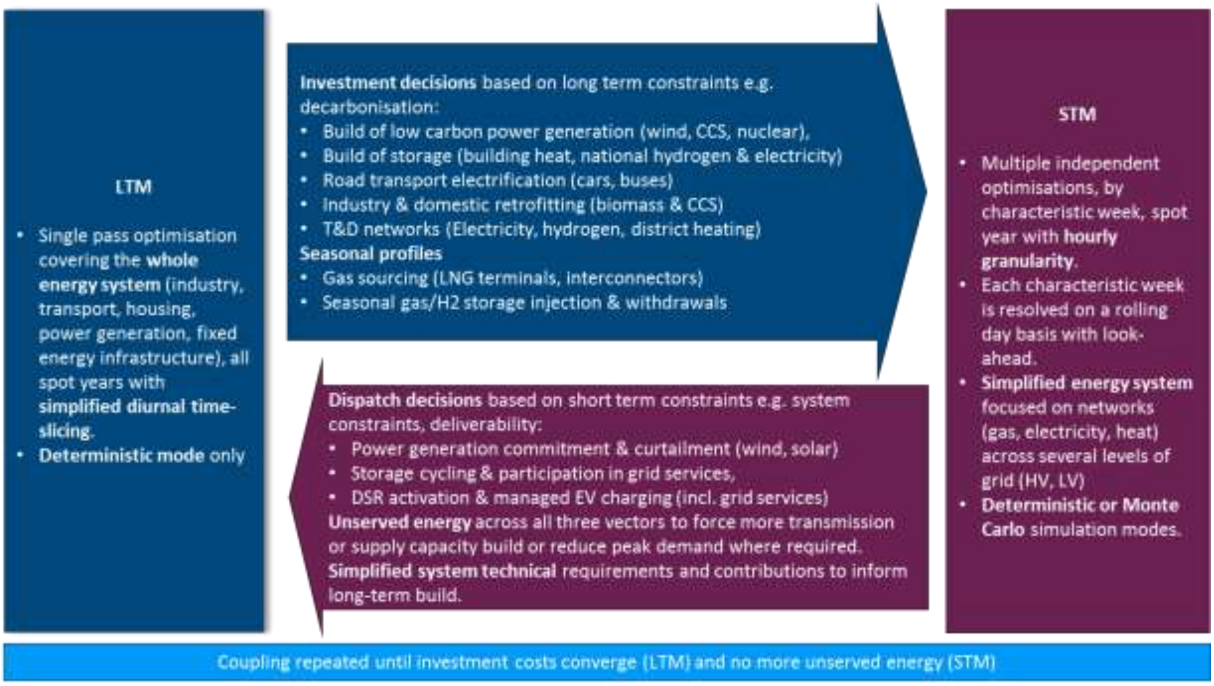
[8] E.g. whether to consider each vintage of technology separately for the purposes of operating decisions.
[9] Sources include historical primary demand data from ELEXON, and intermediate results from other ETI projects including ESME, EnergyPath Networks and Consumers, Vehicles and Energy Integration (CVEI)

Figure 4 LTM-STM coupling

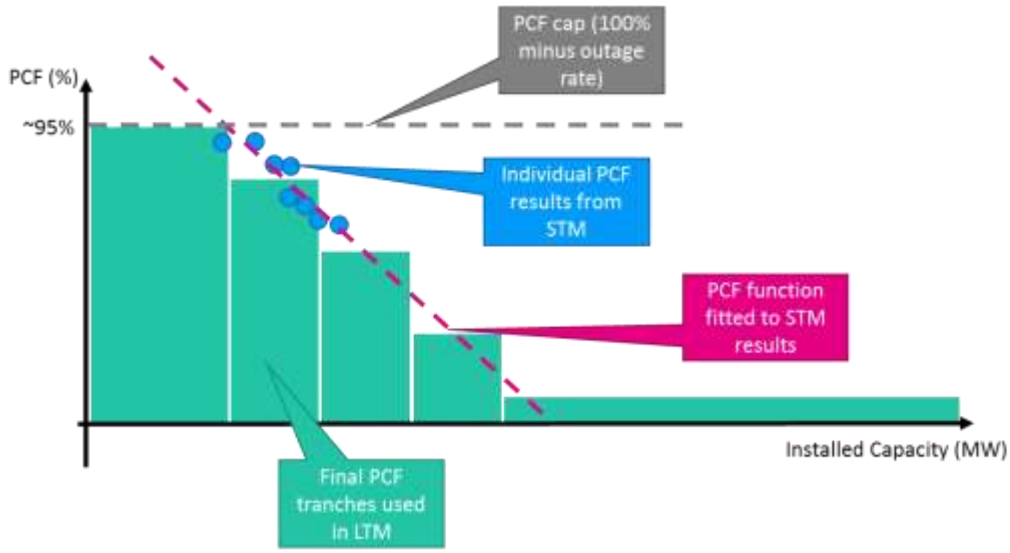


The LTM uses the operational information from the STM to inform the capacity build decisions of the next iteration. In the majority of cases the LTM sees updated information from the previous STM iteration, but there are two areas where the LTM draws on the collective information from a number of previous STM iterations:

- The Peak Contribution Factor (PCF) for each technology represents the ability of a technology to provide power in the peak demand period. The LTM uses a security of supply constraint that applies PCFs and a view of peak demand rather than performing hourly dispatch to ensure peak load is met. PCFs are calculated from the operation of each technology in the STM. The PCF for a given technology decreases as more of that technology is installed (ie a “diminishing returns” effect) meaning that each new unit is less useful in terms of meeting peak demand. The SFM coupling uses STM derived PCF values to build up a function of PCF to installed capacity, which is converted into discrete tranches[10] and passed to the LTM, to be used when calculating how much capacity must be built to meet peak demand. This is shown in Figure 5 below. The PCF function and tranches are updated after each STM run using new information about how a technology ran in the peak period.

[10] The results shown later in this document assume 5 tranches (4 evenly spaced and one very large top tranche that allows for large volumes to be built), but this number is configurable within the input settings of the SFM.

Figure 5 Schematic of converting STM PCF results into LTM PCF tranches



- A heuristic is used to ensure a minimum build quantity of technologies in the LTM that are deemed "sufficiently stable" based on user-defined characteristics (i.e. the capacity has not changed significantly over a number of LTM-STM iterations). This avoids the SFM spending time testing a radically different design for part of the system that has already shown to be stable, when the alternate design will likely be discarded anyway[11].

An "iteration" of the SFM refers to a complete run of the LTM followed by a complete run of the STM. When completing the LTM at each iteration the SFM checks to see whether a cost based stopping criteria (i.e. the delta in costs between successive iterations is within a user-defined tolerance) has been met and that the STM observes minimal (if any) unserved energy (i.e. is there any demand for energy not met by the supply technologies in the model). If both conditions are met the LTM solution in the final iteration is taken as the model result.

The coupling process can take place in two modes:

- **Deterministic:** here the STM runs the 5 characteristic weeks once for each iteration, including the peak system stress week, before passing the information back to the LTM.
- **Monte Carlo:** the STM runs multiple simulations (see section 2.3.4 for details of what is varied between simulations) of the 4 core characteristic weeks, but not the peak week. For the majority of information, the STM passes back the mean of the simulation results to the LTM, however, for the peak capacity factors and level of unserved energy the STM

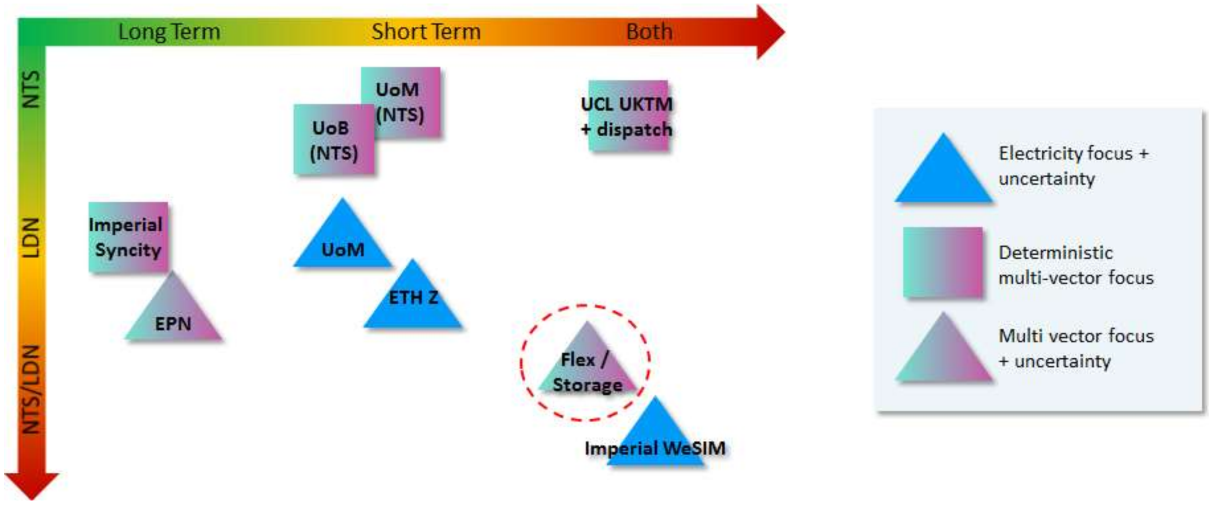
[11] Clearly care must be taken to balance allowing the model sufficient freedom to test alternatives versus 'wasting time' on those which are effectively irrelevant. It is possible to switch this heuristic off, but the model will then take significantly longer to converge on a stable overall solution.

passes back the results from the most 'extreme' simulation[12] in lieu of the deterministically specified week.

2.2.4 High level positioning of SFM versus other energy systems models

As part of the literature review of existing energy systems models outlined in D1.3, a functional mapping was made of some of the key models that answer related questions to the SFM. Figure 6 illustrates, in a fairly stylised manner, where the SFM framework sits in the existing modelling landscape; focusing on integrated frameworks rather than loosely coupled 'patchworks' of tools. At a high-level, the framework is similar to that in the Imperial WeSim model but has been extended from an electricity-focus to consider multiple energy vectors. This increased multi-vector scope necessitates a rebalancing of the level of temporal/spatial granularity seen in this model to be able to explore multiple vectors whilst retaining the ability to explore uncertainty in a tractable manner.

Figure 6 "Stylised" positioning of SFM framework in current modelling landscape



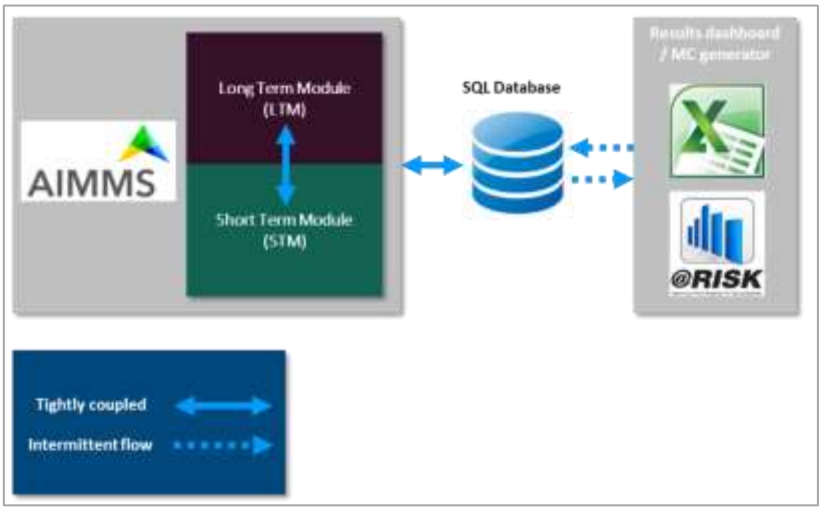
2.2.5 Software environment

The Storage and Flexibility Model uses the same software environment as the ETI's "Energy Systems Modelling Environment" (ESME). This has four key parts, as outlined in Figure 7 below:

1. A Microsoft SQL Server 2014 Commercial[13] database is used to hold all input and output data and perform pre and post processing steps.
2. An AIMMS v4.37 model uses the data from the SQL database to formulate an optimisation problem, which is solved for least cost using a CPLEX v12.7.1 commercial solver license.
3. An Excel based dashboard for viewing results
4. An Excel and @Risk based tool for creating stochastic inputs for Monte-Carlo runs

[12] Based on the simulation with the highest absolute volume of unserved energy, or peak primary energy demand in the absence of any unserved energy.
[13] This is required as the model database size typically exceeds 10GB, and also gives better performance through multi core operation.

Figure 7 SFM software environment



2.2.6 Summary of where key design features are described

This report gives a description of the main design features of the SFM. Table 2 shows where these features are discussed within this report, and where further description is available in other deliverables as part of this project.

Table 2 Where key SFM design features are described

Design Feature	In this report	Further Description
Investment optimisation	2.2.1	D1.3 Long Term Framework
Operational optimisation	2.2.2	D1.3 Long Term Framework D2.3.3 Training Materials
Temporal horizon and granularity	2.3.1	D1.3 Long Term Framework
Spatial Granularity	2.2.1	D1.3 Long Term Framework
Peak representation	2.3.3	D2.1.2 Prototype Summary D2.3.3 Training Materials
Treatment of uncertainty	2.3.4	D1.3 Long Term Framework D2.3.3 Training Materials
Energy Services	2.3.5 Appendix B.4	D1.1 Storage Mapping Report D1.3 Long Term Framework D2.3.3 Training Materials
Technology dispatch and operation	2.3.6	D2.3.3 Training Materials
Network Costing	2.3.7	D2.1.2 Prototype Summary D2.3.3 Training Materials

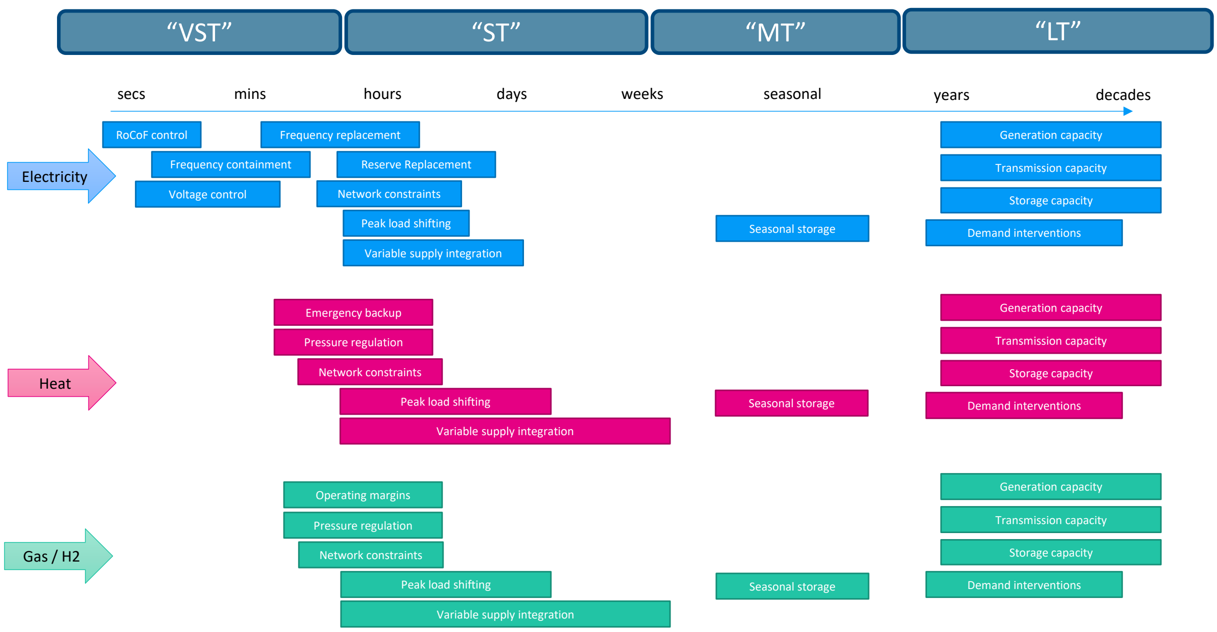
2.3 Further details of modelling approach

The wide scope of the model means there is the potential for a large degree of complexity across a number of discrete dimensions. In the following subsections some the key drivers of complexity are identified, and the design decisions taken to reduce this complexity where possible.

2.3.1 Temporal horizon and granularity

The challenge in modelling the potential role of storage in a decarbonising GB energy system is that the horizon required is large (i.e. 2017 to 2050), but the granularity required is very high for some energy vectors and services (i.e. time steps as short as seconds), see Figure 8 below. Building a modelling framework with granularity of 1 second and a 40 year horizon will quickly lead to an intractable problem, so a compromise has been made as outlined below.

Figure 8 Drivers of storage value across different timescales



The approach taken has been to:

a) Limit granularity to *hourly* steps in STM. This is sufficient for modelling most value drivers that are realised through the energy market (e.g. peak load shifting, variable supply integration). System services (e.g. frequency containment, frequency replacement) are modelled through *holding volumes* of relevant technologies, with technologies held in the required state to provide these short term services if required, rather than by modelling the *utilisation* actions of technologies against these very short-term services. This holding volume is implemented through a series of constraints to ensure that the availability of suitable capacity is greater than the requirement in all periods. The requirement for each system service is calculated endogenously based on the system state (demand level, size of maximum infeed loss)

b) Limit granularity to 5 steps per day in the LTM, where only a coarse representation of supply / demand balance is required to inform the long term investment decisions. Use scalars from the STM to proxy some of the hourly granularity system behaviour (e.g. allow LTM to "see" the hourly peak system load)

c) Use characteristic weeks to understand operation in fundamentally different periods rather than modelling all 52 weeks per year.
    a. The STM is run for 4 individual weeks, one for each season, plus 1 week to represent "peak" conditions (i.e. high underlying demand, low wind and solar output, high interconnector prices). The SFM uses characteristic *weeks* rather than *days* (as in the ETI's ESME framework) to allow for the operation of storage technologies to be assessed across multiple days, and without start/end effects being significant. The inclusion of a week per season allows the STM to represent both "Medium Term" (MT) value drivers for storage (e.g. Seasonal Storage[14]) along with shorter-term value drivers (e.g. diurnal load shifting).
    b. The 5 weeks (1 for each season, and 1 for "peak") are modelled in both the STM and LTM. In the LTM all 5 weeks (and for all years) are included in a single pathway optimisation. In the STM each characteristic week is optimised independently.
    c. While only 5 weeks are represented (as opposed to 52 weeks) the representation of intermittent generation (primarily wind and solar) and underlying temperature driven demand is formed through selecting "typical" profiles, using a long series of historic data. Each of the 4 seasons is represented by a week of typical conditions, with the peak week representing the period of highest system stress and is used to ensure capacity adequacy. In R1.1 of the SFM the peak week uses the most stressful conditions (low wind, low temperature etc) from the historic data set used, broadly representing a "1 in 10 year" set of conditions given available data. Through adjustment of the conditions used to represent the peak week it is possible to tailor the SFM to answer different research questions (i.e. worst-case scenario vs average year).

d) Model each characteristic week in the STM as series of sequential daily optimisations, with "look-ahead" of 10 hours into following day to correctly model overnight dispatch decisions. This reduces number of time steps in a single optimisation horizon from 24*7=168 (single week) to 24+10=34 (single day with lookahead), hugely reducing complexity even when repeating the daily optimisation 7 times. Figure 9 below shows the "look-ahead" concept graphically. Though a daily optimisation is used, each day has a different profile of wind, demand etc representing sequential days of the full week (for example large scale variation in demand at the weekend is captured correctly). The lookahead allows the optimisation steps to be overlapping, allowing for inter-day energy arbitrage.

e) Model spot years rather than all years to 2050, capturing the long term changes that may occur to the energy system without including unnecessary complexity. For the analysis presented here the SFM includes years 2020, 2030, 2040, and 2050. In the LTM all spot years

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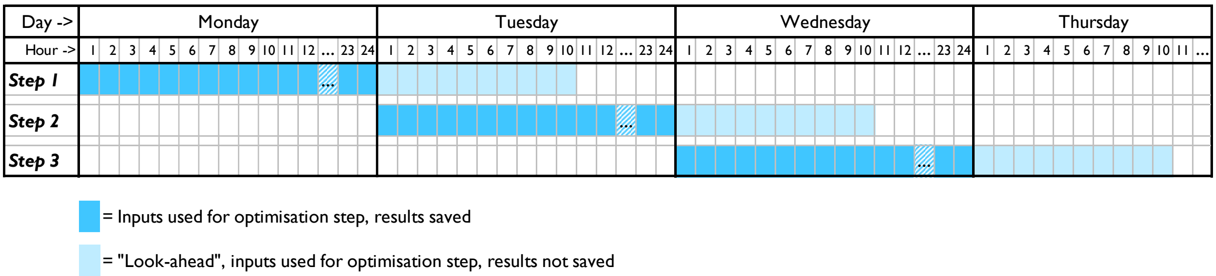
[14] The overarching injection/withdrawal pattern of seasonal storage in the STM is informed by the LTM's seasonal storage operation.

are included in a single pathway optimisation. In the STM characteristic weeks for each spot year each characteristic week are optimised independently.

Figure 9 Example of rolling daily optimisation steps with look-ahead

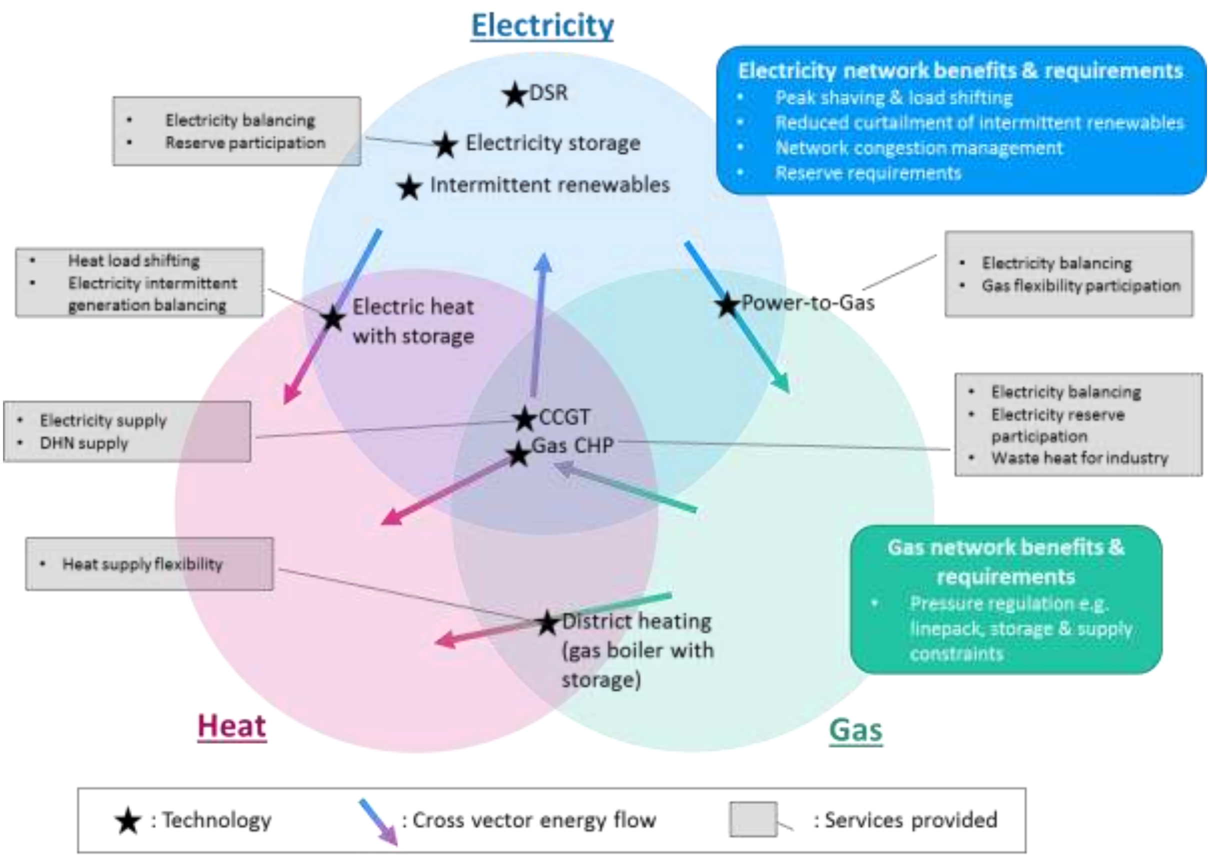


2.3.2 Co-optimisation of energy vectors

One of the key fundamentals of this model is its capability to represent interactions between different energy vectors. However, the approach of each module is significantly different:

- The LTM has a holistic view of the system, modelling a wide range of sectors/energy vectors/services (transport, housing, heat, gas, lighting, fossil fuels, etc.) but has a coarse representation of operation and the interlinkages are proxied via the Peak Contribution Factors (see point below).
- On the other side, the STM has a narrower scope in terms of energy vectors modelled (gas, heat products, electricity, hydrogen) as these are the most significant in terms of operational consideration. However, due to the greater time granularity, the STM is able to model in detail the system operations, especially important during the peak period which is often key in sizing the capacity of the system. During peak periods the supply demand balance of all interlinked energy vectors is evaluated consistently, rather than taking each vector independently (or through a proxy representation of peak, as in the LTM)
    - A (non-exhaustive) illustration of the types of multi-vector interactions modelled in the STM is shown in Figure 10.

Figure 10 Examples of operational multi-vector interactions modelled in the STM



2.3.3 Peak representation

The STM has a more granular representation than the LTM for both the system peak demand requirements (as modelled across the 'peak' system stress week) and how different technologies – including storage – are able to contribute to meeting peak demand.

The STM passes back the insight from this high granularity view to allow peak to be represented in the LTM. The LTM has a series of peak supply constraints which ensure that de-rated peak supply capacity is higher than peak demand, for all nodes, energy vectors, grid level, and time periods.

2.3.3.1 Defining the Peak week

The Peak week is defined by way of key input parameters:

- Temperature
- Wind output
- Solar output

- Power prices from interconnected markets

Temperature and wind output are assumed to be correlated, and the peak conditions have been found by using 10 years of historical data and finding the week with the lowest temperatures and wind output.

Solar output is assumed uncorrelated with winter temperature and wind output, and has been found by finding the single week of lowest solar output from the same 10 year period (but can be different week from temperature and wind)

Power prices in interconnector markets are also assumed independent, and the highest price week in projections from Baringa's pan-European electricity market model have been used to characterise the peak week

2.3.3.2 Peak Contribution Factors

The Peak Contribution Factors (PCFs) allow the LTM to have a reasonable view of how technologies will operate at peak, by de-rating nameplate capacity to represent the capacity likely to operate in peak periods.

In broad terms, the PCF is the contribution of the technology to the system at the period of peak stress and is calculated in percentage terms based on actual output at peak versus the maximum contribution possible (e.g. active capacity or injection/withdrawal rate). The PCFs help set both peak supply and demand across the energy system to the original point of supply. For example, the use of an ASHP to meet peak heat demand will drive higher peak electricity demand, where this is subsequently met by a CCGT this will drive peak gas demand, etc.

Importantly, the LTM needs a significant degree of freedom to be able to re-design the pathway capacity mix in light of new information from the STM. However, using only the previous coupling iteration provides a single point of PCF information *for a given installed capacity.* As a result, PCF functions that relate PCF to installed capacity are built up over successive STM iterations, as shown in Figure 5 of Section 2.2.3.

These are used in the LTM when choosing the correct level of capacity to install. Without a PCF *function*, the LTM does not see the diminishing marginal contribution of the technology as ever more capacity gets built. This can cause subsequent iterations of the LTM to become 'stuck' in one part of the solution space, as a technology, which in the previous STM run had a high capacity and very low PCF does not get an opportunity to be rebuilt with lower capacity. The PCF function has an initial starting seed shape, and is refined via a regression model, which progressively incorporates the results of each new iteration (i.e. single PCF and capacity value) into the overall function.

2.3.3.3 Peak Reserve Margin

Another key property passed from the STM to LTM is the Peak Reserve Margin (PRM). The PRM is a scalar that describes how the total peak capacity requirement in the LTM must change to eliminate unserved energy, based on the previous STM run. Where there is unserved energy in the STM the PRM will be greater than 1, scaling up the total peak capacity requirement up to eliminate unserved energy. When the unserved energy is 0 and there is spare headroom on supply technologies in the STM the PRM will be less than 1, scaling down the peak capacity requirement to reduce system costs.

Through the combination of PRM and the PCF, the LTM has a refined and continually updated view of the requirement for peak demand and the associated and the ability of different technologies to provide this capacity, informed by the detailed STM operational view.

2.3.3.4 Energy volume constraints

The aforementioned constraints are expressed in power terms (MW). If only these constraints were included, the model would tend to be incentivised to build high power/low energy storage assets to meet the peak demand. An energy volume (MWh) constraint ensures that there is enough supply to sustain an extended peak (i.e. peak week demand). In these constraints, storage assets play no role; only supply technologies can contribute to the extended peak energy requirement.

As a reminder, the LTM does not have a bespoke representation of peak like the other seasons. The energy requirement is therefore expressed as a function of the capacity installed (of the consuming technologies) and a profile determined by the STM operation.

2.3.3.5 Unserved energy

The approach above results in the model gradually eliminating unserved energy, whilst keeping capacities at a level reasonable for the level of demand and security standards. The implicit assumption is that unserved energy is undesirable and should be avoided if possible. The model does allow a small amount of demand side management through industrial load shedding DSR, where demand can go unserved but for a specified cost. Similarly, demand side management is included in the model through managed charging of Electric Vehicles and Heat Pumps with storage, which allows underlying demand to be shifted from one time period to another. The stopping criteria of the SFM includes the rule that there is no unserved energy for most energy vectors. However, an exception is made for heat, where a small amount of unserved energy (<1%) is allowed in peak and winter periods, analogous to some homes becoming colder than desirable on the coldest days (with inhabitants responding by wearing more layers of clothing). The choice of how much unserved energy is acceptable before the stopping criteria is met is a choice for the user of the model and may depend on the scenario being modelled (prosperity, decarbonisation ambition etc).

2.3.4 Uncertainty

From the literature review outlined in D1.3 it was identified that uncertainty is a key driver of storage and other flexible assets and should be included in the SFM framework.

Uncertainty in energy system modelling can arise in the following key areas:

- **Long-Term (LT)** projections focused around technology costs or technical characteristics (e.g. what will the cost of different battery technologies be in 2050) or fundamental shifts in underlying energy service demands (e.g. due to population or GDP growth)
  - Long-term uncertainty can be explored in the SFM through the use of multiple scenarios (on costs, demands, availability of technologies etc).
- **Short-Term (ST)** uncertainty is comprised of two interlinked elements:

- **General variation** in day-to-day parameters that effect the optimal ST operation of the system such as behavioural demand patterns, intermittent wind output, interconnector flows, outages etc.
  - This short term variation can be explored in the STM through use of a Monte Carlo mode of the STM. As noted in section 2.2.3 the SFM can be run in two modes (STM deterministic or Monte Carlo). When run in Monte-Carlo mode the STM is run multiple times with different short term inputs (demand, wind output etc) used for each run. The statistics of the Monte-Carlo runs are passed back to the LTM to inform the next iteration.
  - Spatially disaggregated historic data has been used to parameterise distributions from within which temperature (and indirectly space heat demand and heat pump efficiency), wind speed, solar output, and electricity plant outages can be simulated in the Monte Carlo process in the STM. The process allows for distributions to vary both temporally (across and within year) and spatially and for correlation factors to be specified either within key simulation parameters (e.g. wind output between spatial regions or between adjacent time periods) as well as between parameters (e.g. wind and temperature). Interconnected market prices for electricity are a function of their respective future systems. To inform this we have used Baringa's pan-European electricity market modelling results associated with our core decarbonisation scenario to parameterise the distribution parameters. Correlation in prices is represented between relevant interconnected markets as well as with conditions in GB as a function of correlation to GB wind output.
- **Forecast errors** (particularly within day or day-ahead) related to the unexpected variation in demand, output from intermittent generation or tripping of thermal plant that can lead to adjustments in operation of the system ahead of time.
  - Forecast errors are included in the SFM through the inclusion of endogenously calculated System Service constraints (describe in Section 2.3.5 below), which represent the holding of capacity to be used to balance these forecast errors.

Other methods for including uncertainty in the SFM have been considered, including myopic foresight and stochastic optimisation, as detailed in D1.3.

2.3.5 Representation of Energy Services

A key feature of the SFM is the representation of technical system services on top of general energy supply/demand balancing. Both LTM and STM have a representation of energy service with various levels of details. In R1.1 of the SFM all energy services are in the electricity network:

- Frequency containment (Headroom and Footroom)
- Frequency replacement (Headroom and Footroom)
- Reserve replacement (Headroom)

Energy services are included in the SFM through a series of linear constraints, of the following

Provision of Service ≥ Requirement for Service

$$\sum_i S_i^{(p)}(t) \times D_i^{(p)}(t) + H^{(p)}(t) \geq \sum_i S_i^{(r)}(t) \times D_i^{(r)}(t) + H^{(r)}(t)$$

Scalar converting decision variable to provision

Decision variable in model (eg plant rated capacity / headroom / "on state" , demand etc)

Fixed constant provision term

Scalar converting decision variable to requirement

Decision variable in model

Fixed requirement

Energy service requirement calculation

The requirement for each service represents a holding volume that the System Operator would require to provide each balancing service. The requirement for each energy service is a function of:

- The largest infeed loss (headroom requirement for all services)
- The largest demand loss (footroom requirement for all services)
- The inertia provided by spinning plants (Frequency services)
- The inertia due to demand (Frequency services)
- Forecasting errors for intermittent generation and demand (Reserve replacement)

Each of those components are calculated endogenously (with calibrated multipliers) depending on the decision variables in terms of capacity mix, intermittent generation, largest demand component. The utilisation of technologies once committed to a service is not modelled in the SFM.

Operational data from National Grid relating the factors above to the requirement for different electricity service requirements has been used to calibrate the linear scalars used to calculate the energy service requirements in the SFM.

The scalar values used to calculate each energy service are detailed in Appendix B.4.

Energy service contribution calculation

In the SFM the provision of energy services is assumed to be mutually exclusive (consistent with the approach generally taken by System Operators currently) for a single technology at a single node and hence the technology options providing the requirements in the STM can only provide one service in any given timeslice of the model.

- Supply technologies can still provide general energy supply at the same time as a service if it is already generating (i.e. a plant committed to an energy service can participate in the overall supply demand balance, since only its variation to the normal profile is accounted in the energy service contribution).

- For storage technologies, while committed to an energy service the storage level is assumed to remain constant across the hourly timeslice in the STM. As for generation technologies, the SFM represents the *holding* of storage capacity for energy services rather than the *utilisation* of capacity in providing these services. For storage, the holding of capacity for services is done when there is no injection or withdraw, i.e. the state is fixed, and so the storage level remains constant while committed to a service. Therefore, storage cannot provide energy supply and grid services simultaneously.
- For generation technologies, however, the holding of capacity generally implies being held at a fixed part-load generation point, and therefore contributing to the overall supply demand balance while committed to an energy service.
- The assumption that the state of generation and storage technologies remains constant while committed to a service, represents a world where balancing actions are on average equal and opposite (i.e. turn-up requests are balanced by turn-down requests).
- While a single technology at a single node can only provide one service at a time, if the technology is available at multiple locations each locational variant can provide a different system service. Similarly, the technology can switch between applicable services without cost at the end of each hour timeslice.

Each energy service constraint is represented as a national supply-demand balance. The contribution of the supply technologies and energy storage technologies is modelled as their ability to deviate from their normal operational profile at any given time to provide a service to the grid.

For supply technologies, their ability to provide a given energy service is dictated by their headroom (or footroom) and an energy service multiplier which represents the fraction of the supply technology headroom (or footroom) the technology can commit. This multiplier is generally significantly lower than 100%, often due to ramp rate constraints limiting the amount of useful capacity available for energy services. In the STM, the value of this multiplier is an exogenous assumption based on discussions with National Grid, while in the LTM the value is informed by how the supply technology ran in the STM (this captures technology ramp rate constraints and level of commitment to energy services using the high temporal granularity STM). Where a supply technology is heavily committed to an energy service in the STM, in the LTM the proportion of headroom assumed to be used for that energy service will be high, approaching the National Grid derived levels used in the STM itself.

For storage technologies, their contribution is calculated in a different manner. Storage technologies have two aspects to consider, their power output and storage level. In broad terms, if the service has a long duration (reserve replacement for instance) and the storage has a low storage volume/level, then the storage will not be able to provide its maximum output rate for the full duration.

Figure 11 Schema of storage contribution to energy services as a function of storage level/volume

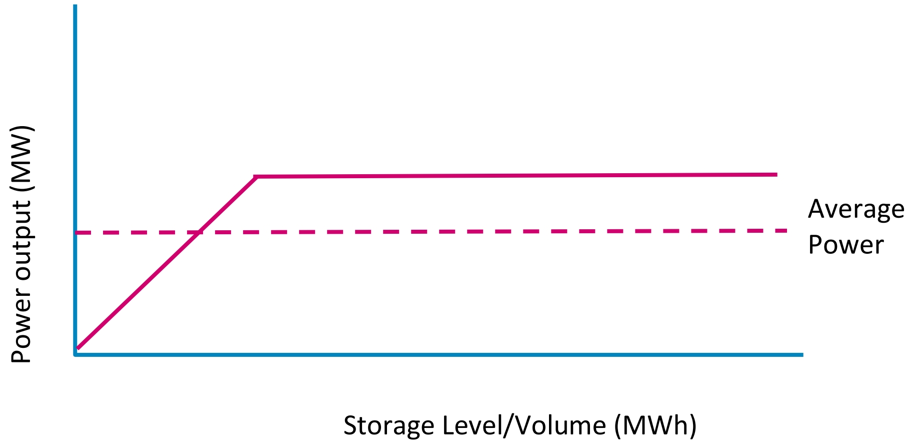


Figure 11 shows a generic example of how the power level that a storage technology can commit to an energy service varies as a function of storage volume. It can be seen that if the storage volume is large, the power output is limited by the maximum power rating of the storage, but if the storage volume is low the power output must be decreased to ensure it can be sustained for the duration of the energy service. The generic "contribution curve" above changes for each energy service and storage technology, due to the different durations of storage output and energy.

Modelling the "contribution curve" fully requires a number of extra constraints to be included in the model. For performance reasons, in R1.1 the contribution of storage to energy services is assumed to be constant at all storage levels, using a calculated Average Power level. The physical assumption being taken here is that the state of storage technologies when starting to commit to an energy service is uniformly distributed across the storage range (i.e. from empty to full). This is a simplifying assumption but is likely reasonable in the majority of cases. Where it may be less reasonable is for short duration storage, where full charge/discharge is possible within 1 hour, and so storage volumes are likely to be either full or empty following energy market operation. Appendix A.4 describes how a more detailed representation of the curve may be included in a future release of the model.

As well as the range of core supply/storage technologies, the SFM has been configured such that managed charging of EVs, managed operation of electrolysers and industrial DSR can also contribute to system services. Interconnectors and shifting of electrified heat are currently assumed not to be able to contribute to system service requirements directly but can still contribute to general hourly energy balancing requirements.

Interaction of LTM and STM

The STM dynamically sees a changing requirement for system services (as both a function of its capacity mix and operating decisions) and decides how different technologies should provide these service requirements; subject to the suitability of the technologies to provide these services and the mutually exclusive provision requirements noted above.

As part of its capacity expansion decisions the LTM sees the impact of its decisions on the overarching system service requirements through an endogenous calculation; for example, the increasing requirement for reserve replacement from deploying more wind or solar. However, it does not have a detailed view of technology operation. The ability of supply and storage technologies to provide system services in the LTM is informed by the detailed operation of the supply/storage technologies in the STM. The operation of technologies in the STM is used to calculate a system service contribution factor per unit of active capacity, which is passed to the LTM to inform capacity expansion decisions (broadly analogous to the PCF values passed from the STM to LTM).

2.3.6 Detailed unit and technology operation

Much of the increased complexity in the STM's representation compared to that in the LTM stems from the detailed operation of its technologies. For example, the power market dispatch has extra constraints to provide a more accurate representation of operation:

- Ramp rates: the output change rate of power plants is constrained by their ramp rate.
- Minimum off time: There is a minimum time for the power plant to come online. During that lapse of time the power plant cannot supply energy or services.
- Unit commitment: The SFM uses two unit commitment modes – linear unit commitment and discrete integer unit commitment (i.e. fully on or off).
  - In the linear representation, any share of the total capacity can be committed to energy services or general supply.
  - In the discrete representation, the capacity given by the LTM is divided into units with a typical size (e.g. 400MW for a CCGT). Each unit is then committed to services or supply as blocks with a Minimum Stable Level (MSL) of generation (e.g. 160 MW for a typical CCGT). When the plant switches on it must first reach its MSL before it can contribute to the wider system and will usually incur a fixed start cost and ramp at a slower rate to reach this MSL than above MSL (defined through the input assumptions of each supply technology). Furthermore, for some plant their part-loaded efficiency at MSL is lower than at maximum output and is assumed to increase linearly between the two.
  - The threshold between linear and discrete representation is definable by the user and relies on the number of units (e.g. individual power stations) of a supply technology. Where the capacity of a supply technology is represented by a small number of large units the discrete unit commitment representation is more appropriate and is used. However, due to the increased optimisation complexity this creates, the SFM uses linear unit commitment for supply technologies, which represent a larger number of smaller units for which the unit commitment effect at the system level is far less material.

In addition to the more detailed operation of supply and storage technologies, the SFM also has a more detailed representation of demand side flexibility than the LTM:

- Industrial DSR (in the form of load shedding): in the STM this is parameterised as a fixed ratio of underlying industrial electricity from the LTM, with exogenous assumptions on the value of this ratio and the price industrial uses must receive to shed load. As noted above, industrial load shedding DSR can also contribute to technical system services or general energy balancing.

- EV 'Managed Charging': instead of a fixed charging profile (e.g. reflecting simple Time of Use shifting or a default unmanaged profile) the user can specify one or more Managed Charging windows across the day and the proportion of EV energy that must be provided within that window (the total volume of energy itself changes depending on the number of EVs chosen in the LTM). Subject to these constraints and a maximum charging rate (based on assumed kW charger rating per EV) the STM has the flexibility over when EVs are charged within these windows. As noted above, EVs can also contribute to technical system services or general energy balancing.
- Electrolysers: have flexibility over when they operate within each day in the STM subject to a daily quantity of hydrogen that must be produced, which is informed by the LTM solution. As long as the electrolysers do not need to run flat out across the day to meet the hydrogen quantity requirement, they can contribute to either technical system services or general energy balancing. In R1.1 of the model it is assumed that hydrogen demand must be met within each day, with no seasonal trend enforced to the STM, which reduces the potential role of medium and long duration hydrogen storage. Appendix A.7 describes how this could be included in a future version of the SFM.
- Building heat storage: the STM makes dispatch decisions over heat storage technologies to help manage the generally hourly energy balancing across the system (e.g. helping to shift electrified heat load). This provides an analogous 'Managed Charging' view to EVs whereby the System Operator optimises the operation of storage hour by hour in line with the requirements of the overall system (whilst ensuring underlying heat service demands are still met). To provide a proxy for cruder Time of Use shifting, the user is also able to define the inputs to constraints which restrict the flexibility of heat storage.

2.3.7 Network costing

2.3.7.1 Electricity – Distribution

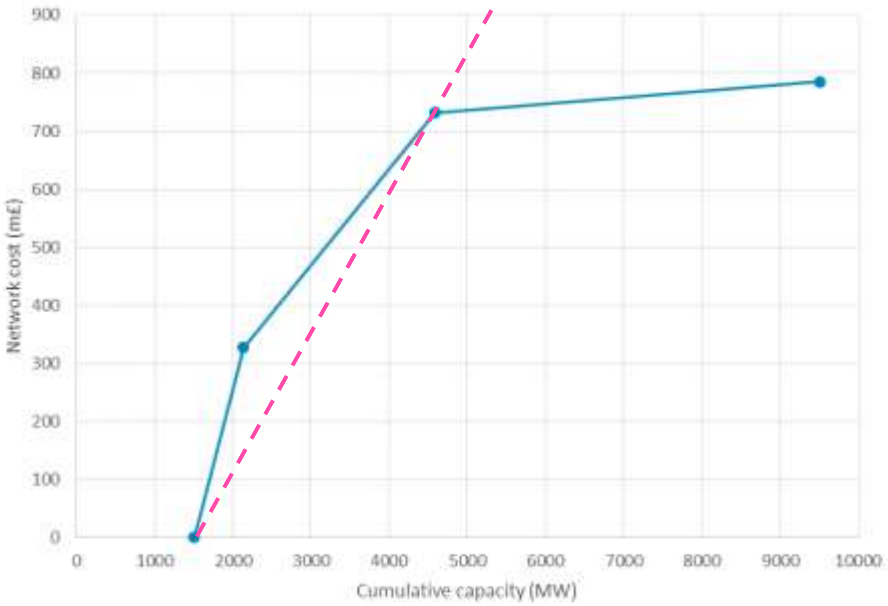
This section details the logic behind the electricity distribution network costing. The flows between geographical nodes are modelled by transmission lines, as per the starting ESME v4.1 model. However, within a geographical node (representing Government Office regions), the electricity network in the SFM is split into three grid levels:

- Transmission (TX)
- High voltage distribution (DX_HV)
- Low voltage distribution (DX_LV))

For the high and low voltage distribution networks these are further separated into urban and rural archetypes. The reinforcement cost functions of the distribution network were calculated based on ETI's internal data. To avoid a non-linear representation in the LTM (which would cause very poor performance) the non-linear cost functions were transformed into a 3-part piecewise linear curves.

However, given the number of nodes and archetypal distribution networks even the piecewise linear model can lead to unacceptable performance implications. Within R1.1 of the SFM the user can switch between a piecewise linear model and a simple linear representation of the reinforcement function. For the analysis described in this report a full linear representation has been used, which assumes the cost curve intersects with the second tranche coordinates as shown in Figure 12.

Figure 12   Piecewise linear and fully linear distribution network reinforcement cost functions



The choice of a single linear tranche introduces an error in the evaluation of the cost of network reinforcement, which is minor in the context of system costs (see Appendix B.3 for details), but results in a significant performance gain in the LTM.

2.3.7.2 Electricity – Transmission

Transmission lines can be installed in the model and are differentiated by different aspects. They have a cost per km (constant throughout years) and a capital cost per capacity installed (decreasing with years). As a result, the model can optimise the time when it is the most suitable to replace/reinforce the power transmission system. There are no economies of scale represented here, i.e. no piecewise linear reinforcement cost function as is used for distribution networks.

2.3.7.3 Gas

The assumption is that the existing gas transportation infrastructure is already more than sufficient to meet the current and future needs in gas. As a result, no additional gas pipelines (transmission or distribution) can be built.

2.3.7.4 H2

As with electricity transmission, hydrogen transmission pipes can be built in the system. However, the main difference is that the capital cost of hydrogen pipelines does not decrease over time.

2.3.7.5 Heat

No transmission of heat between nodes have been represented. District heating requires that heat is produced within the node where it is produced, from a dedicated supply source or from waste heat.

The logic behind the sizing of the district heating system is as follows:

- There are three tranches of district heating capacities, with increasing marginal cost. As a result, the marginal reinforcement cost function is convex in this case (building more district heating has diminishing gains)
- This convex representation reflects the fact that district heating installations would tend to saturate profitable areas first (urban areas) then would marginally cost more when expanding to less densely populated areas.

2.3.8 Summary of key LTM vs STM differences

Table 3 provides a summary of the key differences between the LTM and STM.

Table 3 Overview of key LTM and STM differences

Complexity	STM	LTM
Temporal	• Hourly timeslices • 5 Characteristic weeks (independently optimised) Daily solve with look-ahead • 4 spot years (independently optimised)	• 5 diurnal timeslices • 2 Characteristic days (co-optimised) • 4 spot years (co-optimised)
Co-optimisation of energy vectors	• Vectors: focused on those with material operational considerations: heat products, electricity, gas, hydrogen • Direct interaction between vectors during peak	• Vectors: full energy system representation • Indirect interaction between vectors during peak (PCF) informed by STM results
Uncertainty	• Monte Carlo treatment of day-to-day variation in: wind/solar/temperature profiles, interconnector prices and plant forced outage rates	• Deterministic (scenario dependent) technology costs, efficiencies, and build rates, resource prices and availability
Energy Services	• Energy services: Frequency containment, Frequency replacement, Reserve replacement	• Energy services: Frequency containment, Frequency replacement, Reserve replacement

	• Mutual exclusivity across services	• Averaged contribution by technology informed by STM results
Technologies	• Some (user-defined) technologies aggregated (e.g. ignore build year vintages) • Some technologies are ignored if products not modelled in STM (e.g. conventional fossil liquid car)	• Full energy system representation
Unit commitment	• Discrete representation of operational decisions available to the STM with operational constraints: ramp rate, min off-time, min stable generation • Flexible representation of demand (industry DSR, EV charging, electrolysers, heat storage) with daily constraint conditions (e.g. volume of H2 production) informed by STM	• Only a linear representation is available • No explicit unit commitment variable, but planned load factors by LTM timeslice informed by STM results • Similarly, outturn flexible load profiles from STM used to inform next LTM iteration profile (e.g. EV charging profile)
Network costing	• N/A (no capacity expansion in the STM).	• Two different costing options: Piecewise-linear representation or full linear representation

2.3.9 Discussion of optimality of solution

While both the STM and the LTM deploy optimisation to arrive at their solutions, the separating of the modules means that we cannot be certain that the final solution that the SFM arrives at is the global minimum over the full solution space. However, as noted in the scoping phase of this project the underlying rationale for creating two separate, but strongly coupled optimisation modules, is that it is computationally intractable to represent the combined LTM/STM representation within a single optimisation problem.

Each module provides constraints that bound the solution space of the other module (e.g. PCFs passed from STM to LTM). For this reason, the whole solution space of the total problem is never seen as a single problem, and a global minimum cannot be guaranteed.

The LTM solution from the SFM after a number of iterations is therefore a local minimum, providing a single low cost solution from a very large solution space, and informed by previous STM operational results. It is not the case that simply running the SFM for more iterations will allow the global minimum to be found, as the solution space may be constrained by the STM in such a way that some parts of the solution space can never be accessed.

More detail on how the SFM could be adapted in future to explore more of the solution space and *potentially* better approximate the global minimum – albeit at the expense of longer run-times – is provided in Appendix A.6.

3 Scenario analysis

3.1 Introduction

As part of the SFM project, the SFM tool has been used to provide projections of capacities and operating profiles under two different scenarios for reducing GB CO_2 emissions by 80% by 2050 (compared with 1990 levels). In this report two scenarios are presented, that cover a central view and stress test condition. These two scenarios have been run in deterministic mode, over a pathway covering 2020-2050. In running these scenarios, the functionality of the SFM has been tested and gives an example of the insights that can be gained from the tool.

A further sensitivity has been performed, using the deterministic Base scenario and re-running for 2050 only, with stochastic STM inputs under a Monte-Carlo approach.

In this section the deterministic scenarios and results are described, then further insights coming from the Monte-Carlo analysis are presented.

3.1.1 Caveats to presented results

3.1.1.1 Data assumptions

The SFM was developed using ESME 4.1 as its starting point, and many of the SFM R1.1 assumptions use the ESME 4.1 data set. While these are a reasonable and self-consistent set of assumptions, they do not reflect the ETI's current best view (currently at version 4.4).

Further, an error is present in the input assumptions used to produce the results in this report which effectively improves the efficiency and capacity of all Internal Combustion Engine (ICE) vehicles by ~50%. This results in fewer carbon emissions from the transport sector than would otherwise be the case, which has a knock-on impact on other sectors as widespread decarbonisation is seen later in the pathway.

The results presented here show the type of outputs and insights that the SFM can provide, and are consistent with the input assumptions used, but the reader should avoid interpreting these as representing the ETI's current view.

3.1.1.2 Reproducibility

An outstanding issue in the SFM is that of reproducibility. When the model is run using identical input data, the resulting output technology capacities and operation can vary between nominally identical runs. The differences in output from a single iteration are very small, but due to the iterative nature of the SFM these small differences can increase over multiple iterations such that there are more significant differences by the time the stopping criteria is met.

At a high level the solutions from two nominally identical runs will be consistent (e.g. the level of decarbonisation in different sectors, the total capacity of generation versus storage technologies, etc.) but the capacities of individual technologies can vary significantly between runs, particularly technologies with small capacities compared with the system as a whole (e.g. electricity storage).

This issue is related to the fact that the SFM does not guarantee the optimal solution when using MIP, but rather finds one solution (of potentially many) that is close to optimal in terms of total cost. Where the SFM gives non-reproducible results, each one is a valid solution to the problem. This is discussed in more detail in Appendix A.6. The results presented here represent a single internally consistent solution to the problem, but if another user was to try to reproduce these results they would likely get a different (valid) solution to the problem.

The reproducibility issue is related to the way the AIMMS optimisation framework builds the optimisation problem, where the ordering of the problem and constraints is not specified in the input data but has an effect on the MIP search method. As a part of this project the issue has been identified and raised with AIMMS, who have recently fixed the issue in the latest version of AIMMS, however this fix came too late to be used for the analysis presented in this report.

3.2 Description of deterministic scenarios

Two deterministic scenarios have been studied. The SFM handles long term uncertainty through scenario analysis, and the scenarios presented here probe the sensitivity of the model to uncertainty around how difficult decarbonisation will be to achieve. The Base scenario represents a central view of all parameters and is considered the most likely scenario to occur. The No CCS scenario is a kind of "stress test" for the model and represents one of the more extreme possible scenarios in terms of the changes that need to be made to the capacity mix across the pathway.

3.2.1 Base Scenario

The Base scenario is a central view of current and future technology costs, operational parameters, build constraints, demands, resource costs etc. It includes central values in the face of uncertainty over all assumptions. The Base scenario seeks to give a balanced view of the potential for technological advancement across the whole of the energy system and is neither conservative nor optimistic. A number of carbon capture and storage technologies are available to be deployed if found to be the lowest cost option.

3.2.2 No CCS Scenario

Under the No CCS scenario all Carbon Capture and Storage technologies are removed from the model. This removes one of the key routes to decarbonising and affects all sectors. From previous experience using Whole Energy Systems Models (e.g. ESME) for strategic pathway analysis it has been found that the availability (or otherwise) of CCS technologies is one of the key drivers of the solution and requires more radical changes to supply and demand technologies to allow for an 80% reduction in CO_2 emissions by 2050.

3.2.3 Common assumptions

The Base and No CCS scenarios share almost all assumptions. The only difference is the availability of CCS technologies.

Many of the assumptions in both the Base and No CCS scenarios come from the ESME 4.1 Reference case, the starting point of the SFM. The ESME 4.1 Reference[15] provides a reasonable and internally consistent central point for all long term assumptions, covering a wide range of current and proposed energy technologies and their likely evolution. These ESME Reference assumptions are used for the deterministic SFM modelling presented here (ESME, however, is typically run in monte-carlo mode, to include the uncertainty around long term assumptions). The assumptions that are consistent with ESME 4.1 Reference include:

- End user demand assumptions
- Technology assumptions
  - Costs
  - Build rate and quantity constraints
- Carbon emission constraints levels (scaled to GB rather than UK)

A number of new assumptions have been developed as part of the SFM and are used in both the Base and No CCS scenario. These are documented in detail in a separate deliverable, the Final Assumptions Book (D2.3.2). In summary, the assumptions added as part of the SFM R1.1 include:

- Storage technology costs and their evolution
  - See cost table in Appendix B.1
- Dynamic dispatch assumptions for supply technologies
- Energy service requirements
  - Parameters for endogenous calculation of requirement within model
  - Parameters for endogenous calculation of provision from generation and storage technologies
- Shaping profiles to allow for automatic conversion of hourly LTM profiles to hourly profiles used in STM
- Assumptions on managed charging for EVs, home space heat storage, and industrial load shedding DSR
- LDN reinforcement cost curves
  - Using a linear incremental cost in the Base and No CCS scenarios

The key settings in the Base and No CCS scenarios are identical:

- Pathway
  - 2020-2050

[15] The underlying ESME dataset and reference book is available here http://www.eti.co.uk/programmes/strategy/esme

- 4 spot years (2020, 2030, 2040, 2050)

- Seasons
  - 5 seasons (including “peak”)
  - Each represented by a characteristic week
- STM Look-ahead period
  - 10 hours
  - This value has been chosen to include the next morning peak demand and allow for overnight arbitrage opportunities
- Design Standard for all energy supply (including network capacity), applied by energy vector with nodal and global constraints
  - 15% headroom over peak demand (10% for Hydrogen)
  - The choice of the design standard is up to the user / system planner; potentially the values above could be fine-tuned down given the detailed representation of Peak in the SFM, but this would come at the cost of longer run time as the model takes more iterations to reduce unserved energy

3.3 Deterministic scenario results

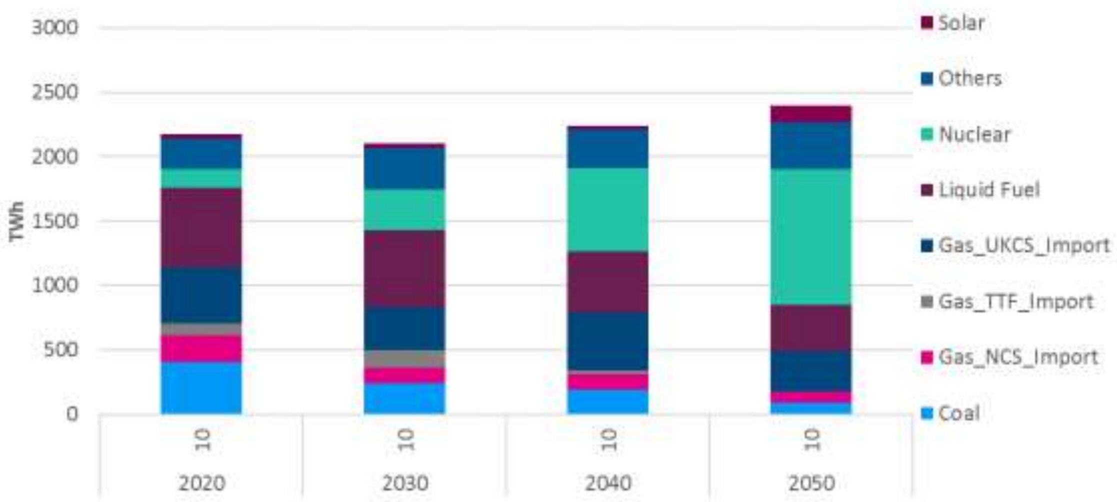
3.3.1 Base Scenario

The wide scope of the SFM leads to a wealth of results and insights that can be gathered from the model. In this section some of the many outputs available from the SFM are highlighted, and a narrative around the nature of the pathway solution from the Base scenario is provided. While the model is a holistic multi-vector model, results are divided by energy sector. Where there are strong linkages between the investment and operation decisions across different energy sectors, these are highlighted.

3.3.1.1 System wide

The supply of all primary energy is shown in Figure 13. This includes all primary energy, before conversion and any losses incurred as a result. The obvious trends are the reduction in liquid fuels over the pathway (primarily for transport), and the large increase in nuclear fuels used for electricity generation. Coal supply reduces significantly over the pathway, displaced by nuclear fuels for electricity generation. Gas supply, however, shows only a moderate reduction, reflecting the continued role of gas for heating and its role in electricity generation with CCS technologies towards the end of the pathway. Total supply shows a moderate increase over the pathway, as population related growth is largely offset by efficiency savings.

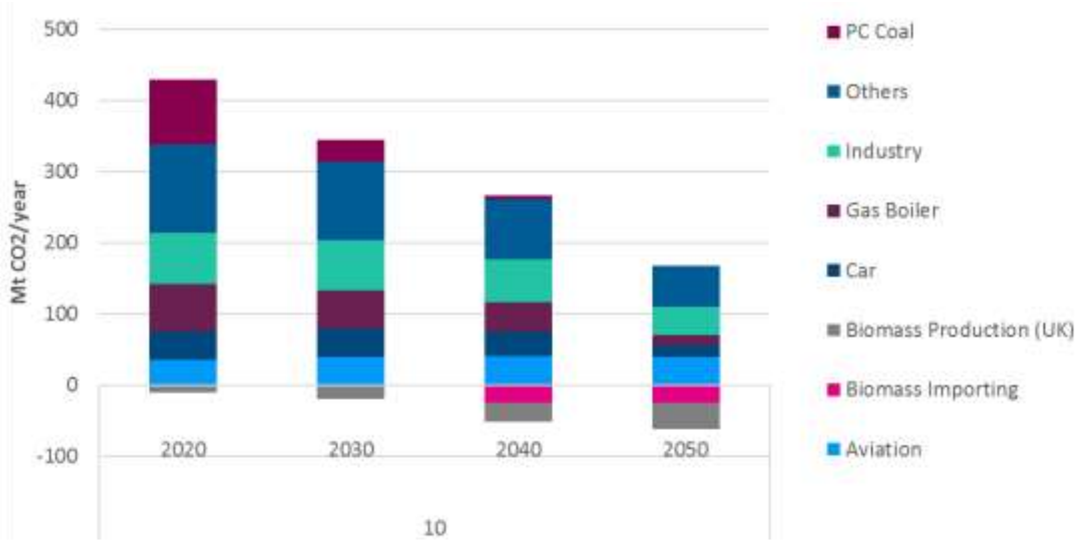
Figure 13 Primary Energy Supply, annual, 2020-2050, Base



The evolution of CO_2 emissions over the pathway is shown in Figure 14. Emissions show strong reductions, consistent with the carbon volumes constraint assumptions from ESME 4.1 (aligned with UK carbon budgets and the 80% reduction in emissions in 2050 compared to 1990 levels). Total net CO_2 emissions (ie net of emissions captured by biomass and CCS) in 2050 are 105 Mt per year. Reductions are driven by:

- Vehicles switching to electric variants (mainly plug-in hybrids)
- Unabated CCGTs replaced with CCGT + CCS
- Coal being phased out
- Electrification of heat by replacing gas boilers with Air Source Heat Pumps (ASHPs) and electric resistive heating
- Industry adopting CCS
- Significant use of biofuels, which contribute 62 Mt of negative emissions, captured through their production

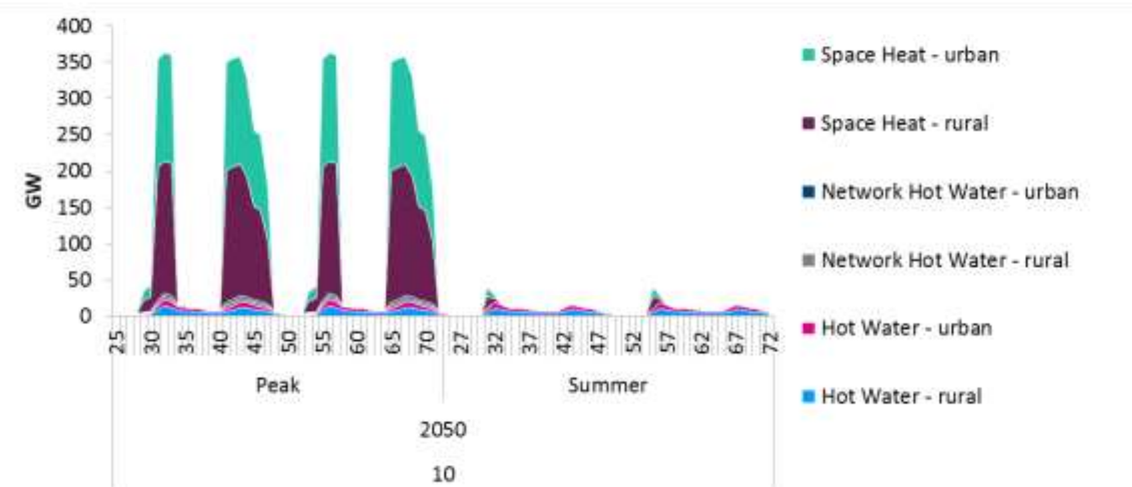
Figure 14 CO_2 emissions, annual, 2020-2050, Base



3.3.1.2 Heat

Demand for heat is the largest single end use demand in the model, both in terms of annual energy (TWh) and peak demand (GW). Demand for heat also shows the biggest variation of all the energy vectors, both diurnally and seasonally as shown in Figure 15. The SFM must build adequate supply capacity to meet these large peaks in heat demand to avoid unserved energy.

Figure 15 Heat demand profile, 2 days[16] in Peak and Summer, 2050, Base



[16] Note, in all hourly dispatch charts shown in this report the X axis shows time, split by hour of week, by season, and by year. In the deterministic scenario results hours 25-72 have been selected, i.e. 12am Tuesday morning to 11pm Weds of each characteristic week.

Figure 16 shows the total capacity of heat supply technologies over the pathway. The total supply capacity initially decreases from 2020 to 2030, as old electric resistive heating is retired and not replaced, then capacity rises throughout the rest of the pathway. While there is some limited scope for heat demand reductions (through building retro-fit options) this is offset by population and GDP related growth, as shown in the annual supply in Figure 17.

Figure 16 shows gas boiler capacity decreasing over the pathway, replaced by Air Source Heat Pumps (ASHPs) and new electric resistive heating, as the heating sector is electrified. Gas boilers that remain in 2050 are used for peak periods only and contribute little to annual heat supply. Large volumes of building level heat storage technologies ("Building Hot Water" and "Building Space Heat") are built in all years, used to provide flexibility to the heat sector by smoothing electrified heat operation.

The SFM calculates the running profiles for supply technologies endogenously (compared with exogenous max running profiles for some technologies in ESME). Using the endogenous profiles in the SFM, the SFM favours running ASHPs at higher load factors (reducing their Levelised Cost of Energy, LCoE) to provide increasing volumes of low carbon heat, while gas boilers and building heat storage provide flexibility and peak supply.

Figure 16 Heat capacity, 2020-2050, Base

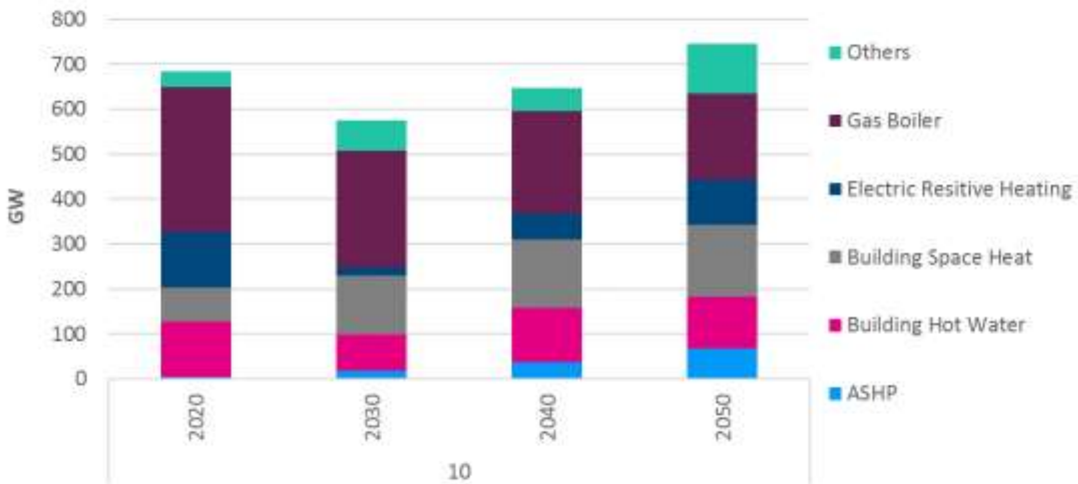
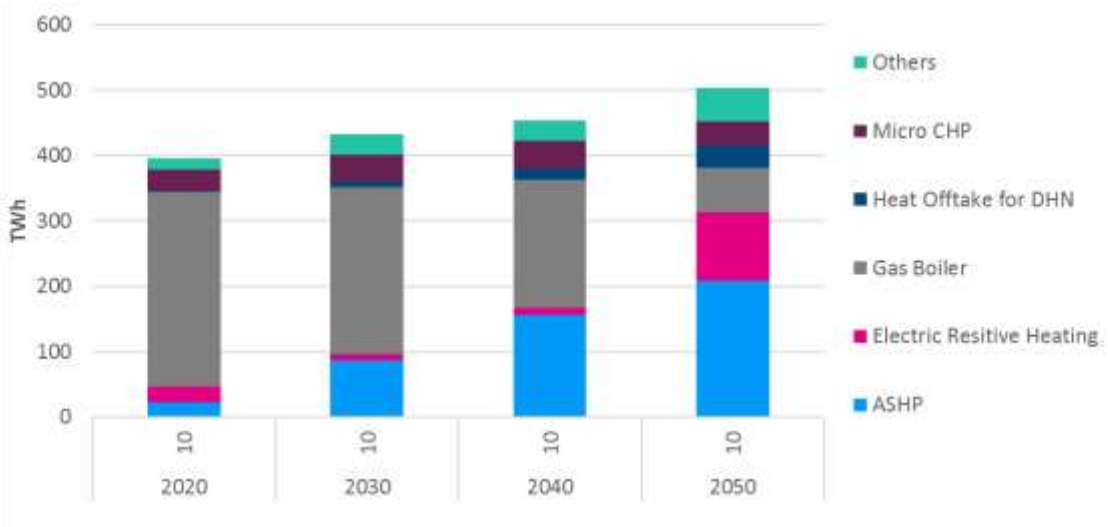


Figure 17 Heat supply, annual, 2020-2050, Base



To understand how each technology is operating, the SFM can provide hourly dispatch profiles for all technologies in all periods (coming from the STM). The dispatch profiles for heat technologies for a 48-hour period at Peak in 2050 is shown in Figure 18. This Figure includes both generation (purely positive) and storage (positive and negative) operation, which can be difficult to interpret on a single chart.

Figure 18 Heat supply, 48 hours at Peak, 2050, Base

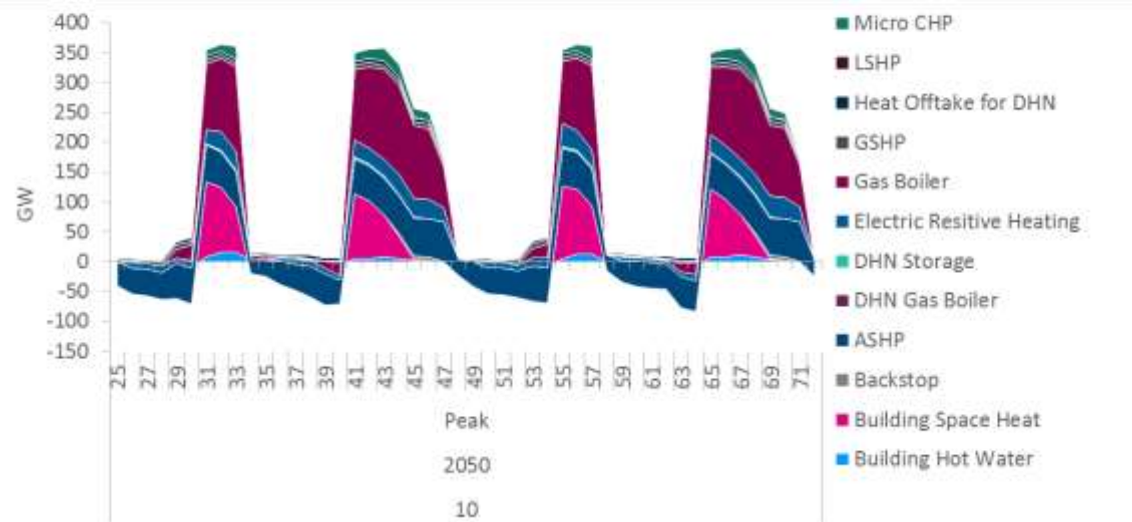


Figure 19 to Figure 21 show the dispatch profiles in Peak 2050 for gas boilers, ASHPs, and building storage technologies in 2050 respectively. It can be seen that gas boilers operate in a peaking mode, providing significant capacity but only in the highest demand periods. ASHPs, however, are run at close to baseload operation, despite the highly variable shape of heat demand. It is building level heat storage that allows ASHPs to run in this way, soaking up heat in periods of low heat demand and supplying it again in high demand periods, which increases the load factor (and therefore lowers the LCoE) of ASHPs. While each technology is represented as an independent heating unit (in terms of cost assumptions) the operation is more like that of a "hybrid" heating system, with a mix of technologies included in a single heating unit. This hybrid operation results from the way the SFM (and ESME) pools all supply and demand at each node and grid level. In reality hybrid operation like this may require dedicated hybrid units, which have higher costs than the average of the single technology units currently included in the SFM.

While Figure 21 shows the output of the building heat storage technologies, Figure 22 shows the storage volume of these technologies for 48 hours of the Peak week in 2050. These technologies are being used over their full storage volume – fully charging and discharging on at least daily basis. This is due to the relatively high losses incurred when storing heat in these technologies (which disincentivises the holding of heat energy for long periods of time), and due to constraints on the size of storage tank that can be fitted per building (limiting the volume of the storage technology, MWh, compared with its output capacity, MW). While the SFM could choose to use heat storage to shift energy from one day to another, it is found in these results that due to the reasons above this operating mode is not favoured.

The high variability of output of gas boilers in peak periods results in large swings in supply on the gas network, but due to the existing capacity and inherent storage of the gas network this can be managed quite easily. Were the same fluctuations to be seen in the electricity network (through electrified heat technologies) this would be far more challenging to manage. As a result, the SFM prioritises storage in the heat sector, allowing electrified heat demand to be smoothed somewhat, and therefore having a smoothing effect on electricity demand.

Figure 19 Gas Boiler supply, 48 hours at Peak, 2050, Base

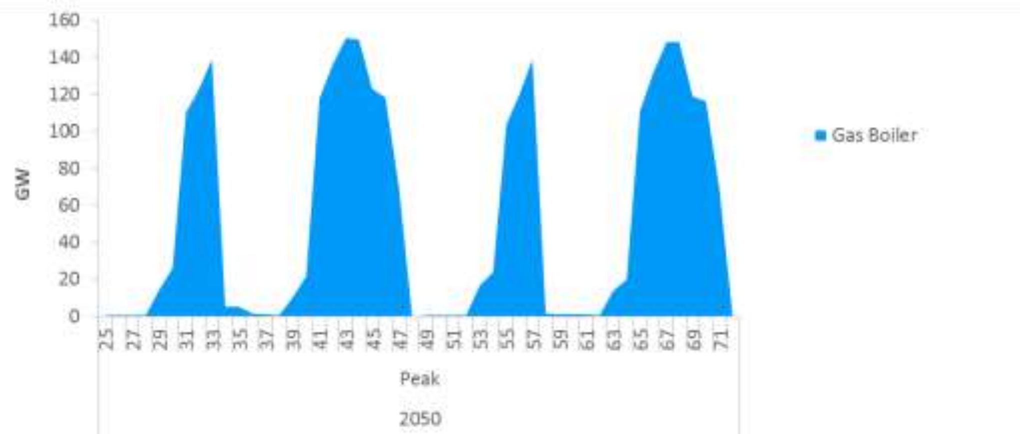


Figure 20 ASHP supply, 48 hours at Peak, 2050, Base

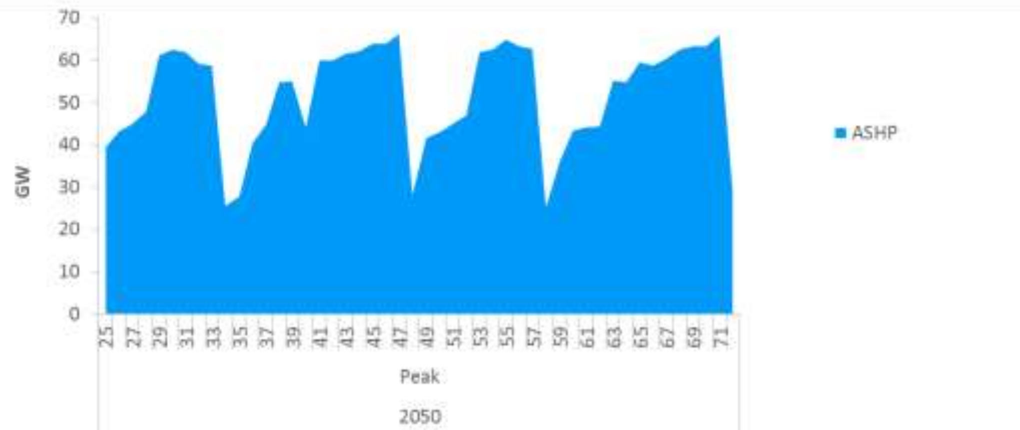


Figure 21 Building heat storage supply, 48 hours at Peak, 2050, Base

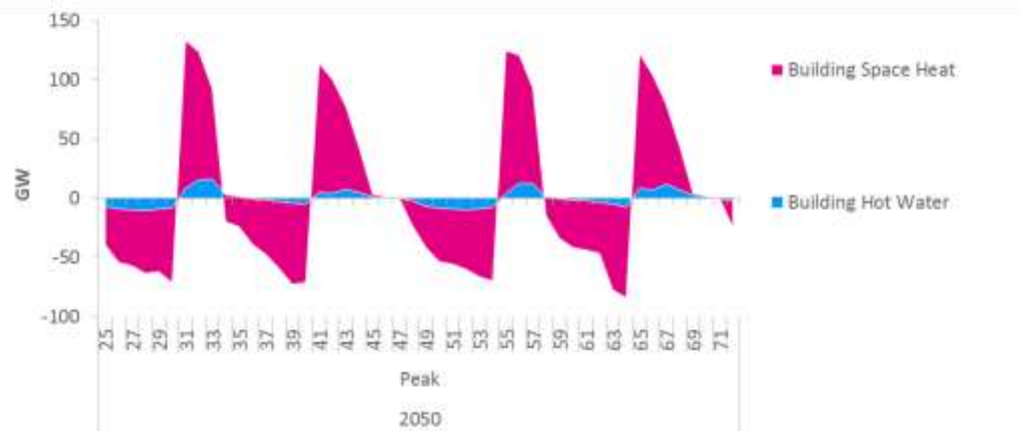
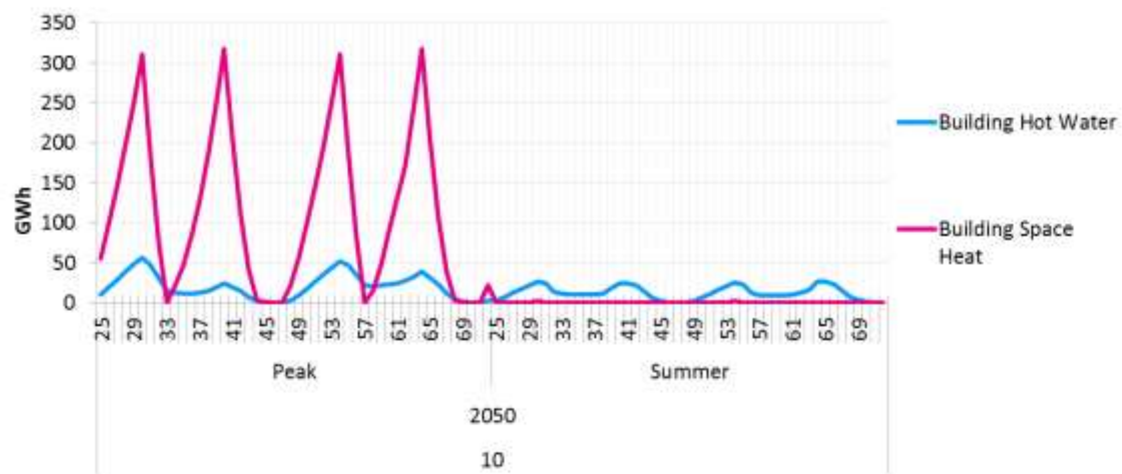


Figure 22 Storage volume hourly profile – building heat storage, 2050, Base



However, despite the smoothing effect of building level heat storage, electricity demand is significantly affected by the electrification of heat. Figure 23 shows electricity demand at Peak in 2020 and 2050, where the large increase in demand from ASHP and Electric Resistive heating can be seen. The SFM uses a number of technologies to help manage this peak demand, including significant volumes of storage in 2050. The largest electrical storage technology in capacity terms is Pumped Heat – a storage technology that converts electricity to heat for short term storage, then converts back to electricity again when discharged. Figure 24 shows the dispatch profile for Pumped Heat, where it can be seen to be charging in off-peak periods and discharging in peak periods to smooth electricity supply.

Figure 23 Electricity demand, Peak, 2020 and 2050, Base

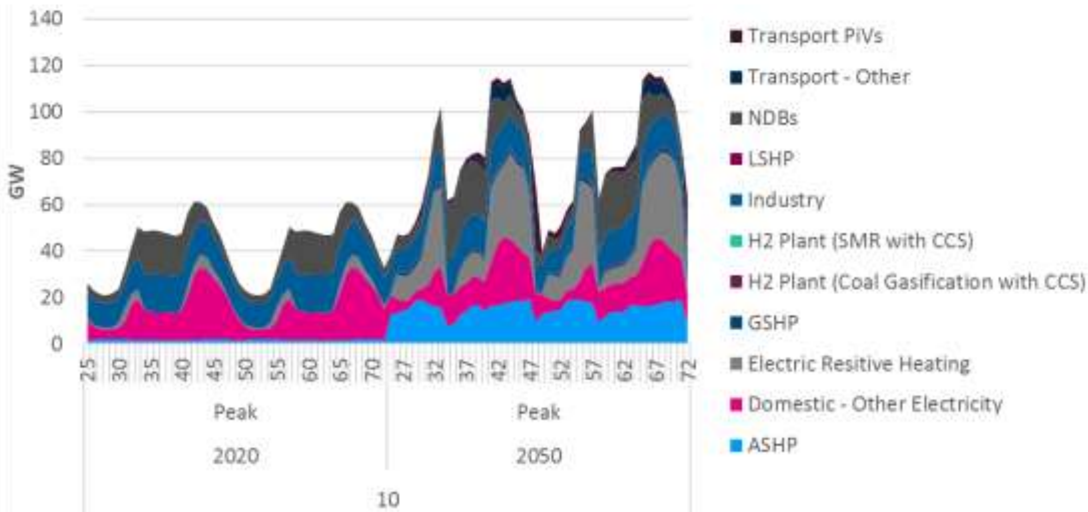
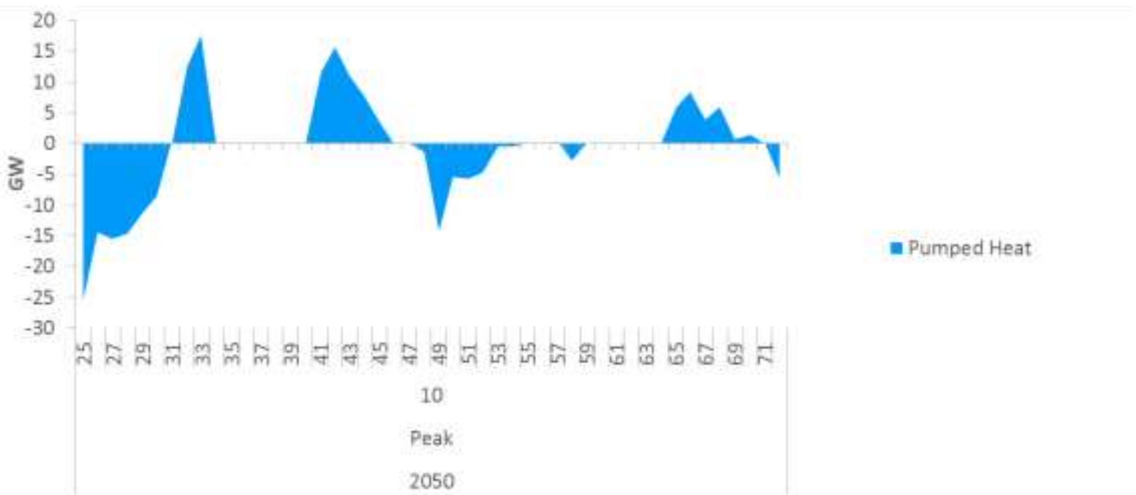


Figure 24 Pumped Heat storage output, Peak, 2050, Base



Within the heat sector a small amount of unserved energy is observed. The SFM has logic to progressively eliminate unserved energy if enough iterations are performed, but there is a trade-off between completely eliminating unserved energy and model run time. In the Base scenario results a small amount of unserved heat is present in peak periods in 2050. This can be observed through the dispatch profile of the heat “backstop” technology, as shown in Figure 25. This unserved energy totals ~120GWh in the Peak week in 2050, compared with 30.5 TWh of demand, which is well within the 1% unserved energy stopping criteria. In physical terms this is equivalent to some homes forgoing normal comfort levels for a few hours during a low probability extended cold spell (approximately 1-in-10 years). In an average cold spell (i.e. “Winter” week) no unserved energy is observed.

However, the numbers above are for Great Britain as a whole and hide regional differences. Figure 26 shows the break-down of unserved energy on a nodal basis. Virtually all unserved energy is found within London, where the volume of heat demand is ~5.4TWh for the Peak week in 2050. Unserved energy is 2.2% of demand for London alone, though only in the Peak week. London is the most challenging area for the SFM to ensure demand is met due to a combination of very high demand density and a lack of space for storage and generation technologies.

Figure 25 Backstop technology supply, Peak and Summer, 2050, Base

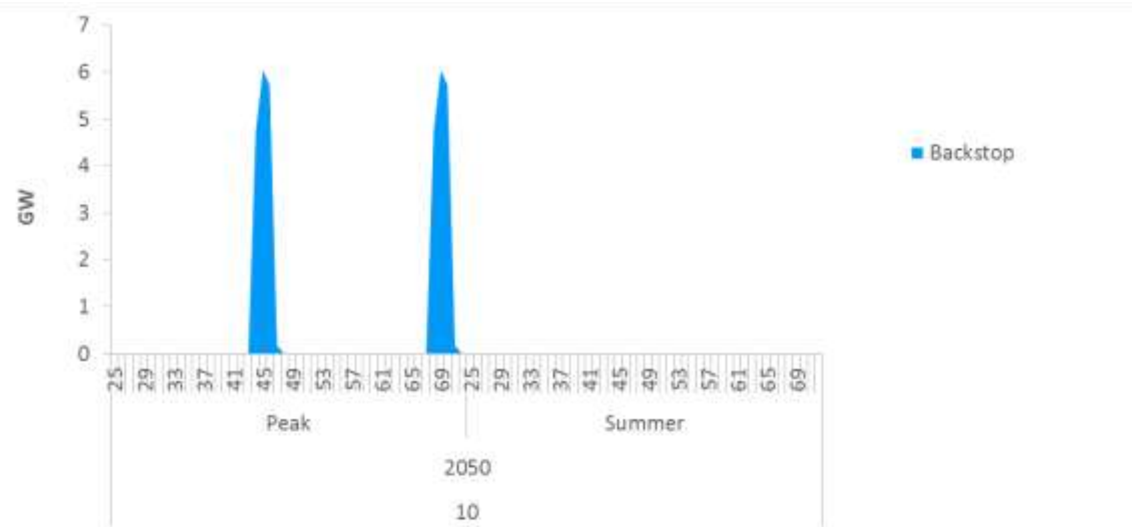
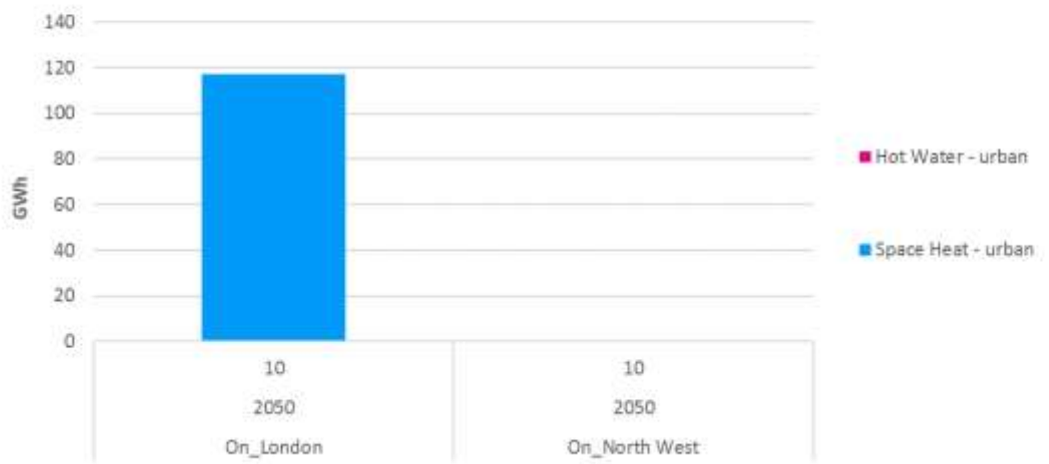


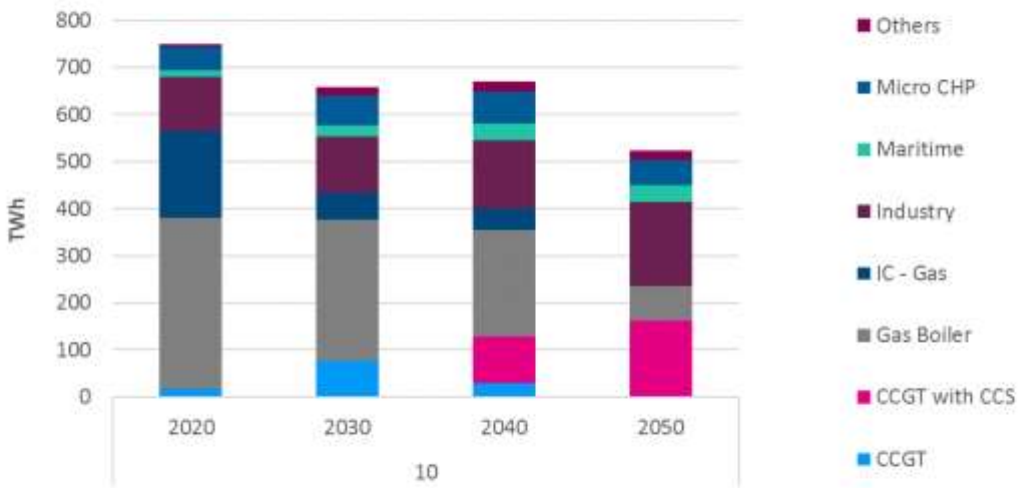
Figure 26 Unserved energy, nodal breakdown, 2050, Base



3.3.1.3 Gas/H_2

Gas and hydrogen use is fully represented in the SFM, with supply, network and consumption technologies available to the model. Gas demand is significantly affected by changes in both heat and electricity sectors, as it is currently a major fuel for both. Over the pathway, demand for gas decreases substantially, as shown in Figure 27. Gas consumption decreases by ~30% over the pathway, primarily due to near elimination of use in Gas Boilers for heating and a reduction in gas exports over interconnectors. In 2020 CCGTs are little used, with existing Coal fired electricity generation being more cost-effective. However, over the pathway gas use for electricity production progressively increases, with increasing use of CCS technologies to ensure significant decarbonisation by 2050.

Figure 27 Gas / H_2 consumption, annual volume, Base



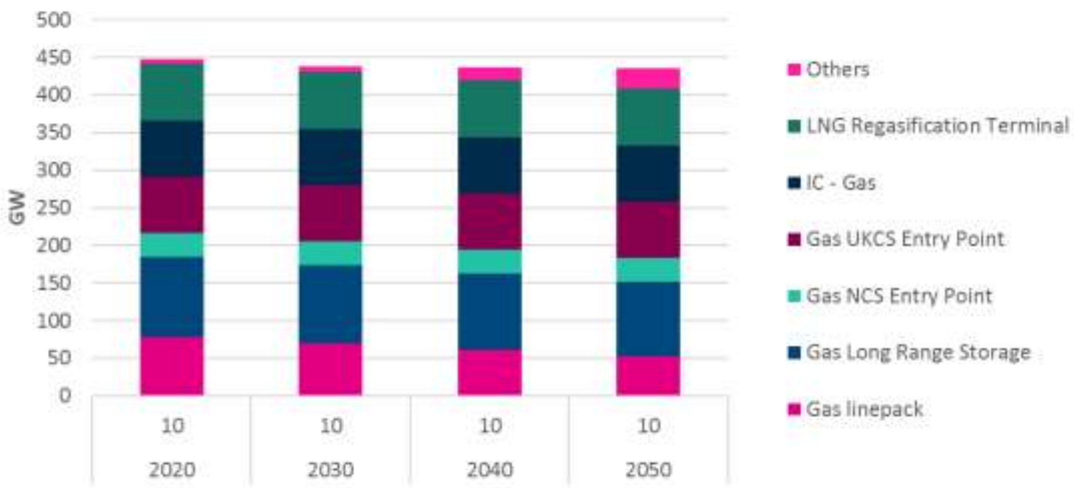
Gas supply capacity remains fairly stable across the pathway, as shown in Figure 28. Many of these assets have long technical lifetimes and so existing capacity is sufficient as gas demand decreases over the pathway. This decrease is seen both in terms of annual energy demand (Figure 27), and peak demand (Figure 29).

The Base Scenario results do not show a need for significant new gas storage. The combination of existing gas storage (dominated by Rough, which is assumed to remain open in the data used for this project[17]) and further flexibility provided by transmission linepack capacity is enough to smooth swings in gas demand projected in these results.

Figure 30 shows the hourly storage energy volume for gas storage technologies. It can be seen that long-range Gas Storage follows a seasonal charging cycle (shifting gas demand from Winter to Summer) while linepack provides short term flexibility over peak periods only (shifting demand from morning and evening peaks to midday and overnight periods). In Summer months, the short term flexibility available from long-range storage is sufficient to balance supply and demand, and linepack is not used. It is arbitrary which is used in the model, the key result is that no new build storage capacity is required.

While hydrogen is fully represented in the SFM, in the Base Scenario it is not favoured over Gas + CCS as a low carbon gaseous fuel for heating, industry and electricity production.

Figure 28 Gas / H_2 supply capacity, Base



[17] The owner of Rough gas storage facility, Centrica, announced in April 2017 that they would be closing Rough as storage facility due high refurbishment costs and reduced seasonal arbitrage revenues: https://www.centrica.com/news/cessation-storage-operations-rough
The cushion gas in Rough will potentially allow Rough to remain supplying Winter gas for a number of years, likely depleting in 2020.

Figure 29 Gas / H_2 supply, 48 hours at Peak, 2020 and 2050, Base

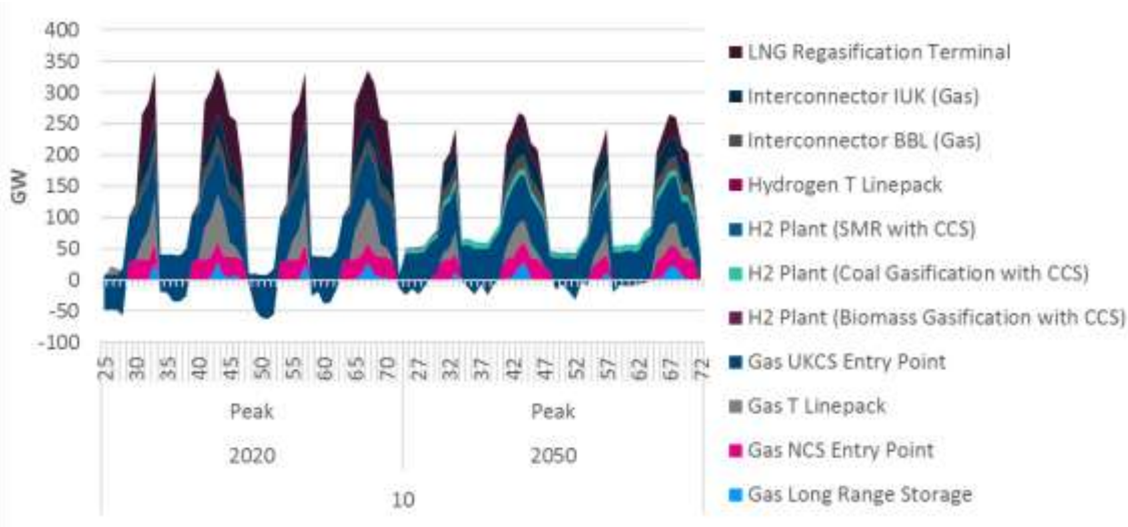
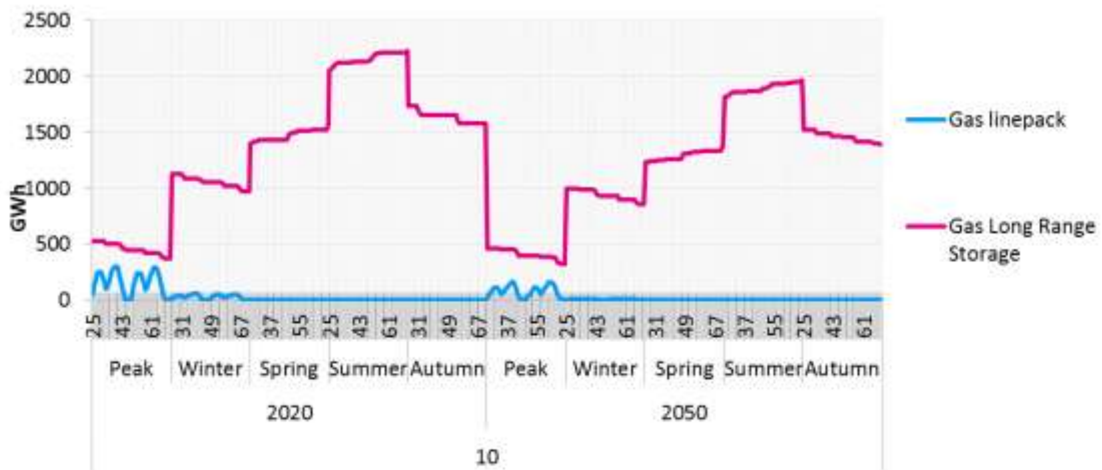


Figure 30 Storage volume hourly profile – gas storage technologies, Base



3.3.1.4 Electricity

Electricity is the most complex energy vector to model due to the lack of natural storage in the system. The enhanced representation of the electricity sector in SFM (versus ESME 4.1) is primarily due to higher granularity dispatch with technical constraints applied, better representation of network capacity at different grid levels, and the inclusion of system services.

Annual demand for electricity increases significantly over the pathway as shown in Figure 31, primarily due to strong electrification in heat and transport sectors. It can be seen that there is a significant increase in Nuclear generation over the pathway, providing low carbon baseload electricity. This displaces unabated coal and gas fired generation, which is not used in 2050. By 2050 the electricity sector is virtually decarbonised, with the bulk of generation coming from Nuclear or CCS technologies (including negative emissions from Biomass with CCS), and some limited generation from renewables. These results are similar to those in ESME 4.1 Reference scenario, though total supply is higher in the SFM results, primarily due to increased electrification of transport (this is discussed in more detail below).

Figure 31   Electricity supply, annual volume, Base

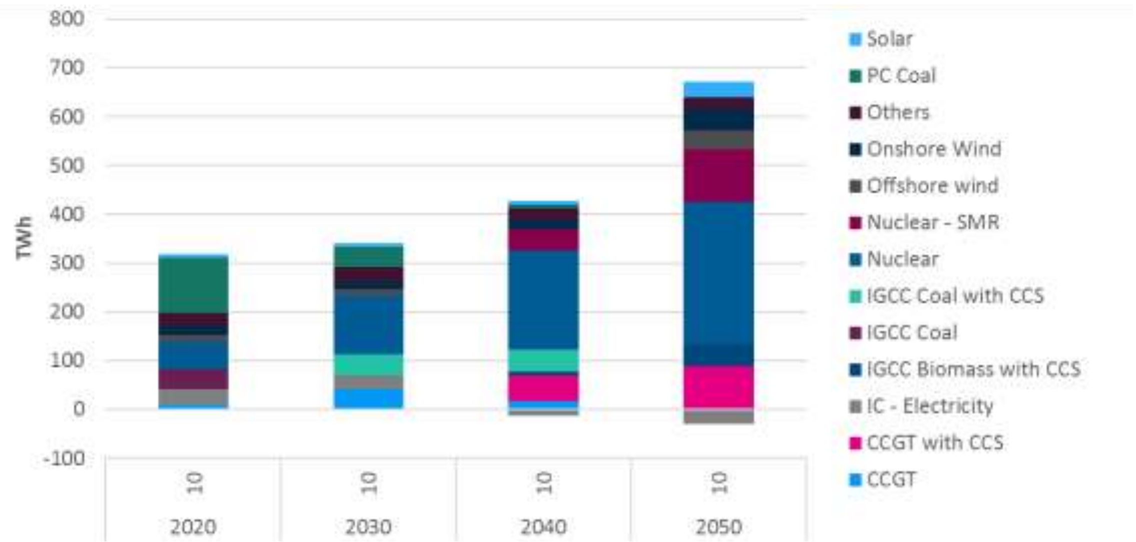


Figure 32 shows the electricity generation capacity evolution over the pathway. A similar trend to supply volumes is seen, with Nuclear and CCGT with CCS capacities increasing, but unabated generation decreasing markedly. Renewable capacity shows moderate increases over the pathway but remains a relatively low part of the supply mix. Unabated CCGTs decrease in capacity but remain in 2050, where none remain in the ESME 4.1 results. These plant are used as mid-merit plant for electricity generation in 2040 and are kept on the system in 2050 primarily to provide additional headroom at peak only, as shown in Figure 33. The SFM has a more detailed representation of peak demand, and this drives many of the capacity decisions seen in these results.

Other differences to the ESME 4.1 results include lower capacities of intermittent renewable technologies, and higher capacities of flexible CCGT with CCS, a result of the more detailed representation of flexibility requirements (i.e. the requirement for capacity to be held for system services is included in the SFM but not ESME 4.1). There is an increase in inflexible Nuclear capacities in the SFM results. While these technologies have limited flexibility (compared with CCGTs for example), they provide a high amount of inertia to the system, which reduces the requirement for Frequency Containment and Frequency Replacement.

Figure 32 Electricity generation capacity evolution over pathway, Base

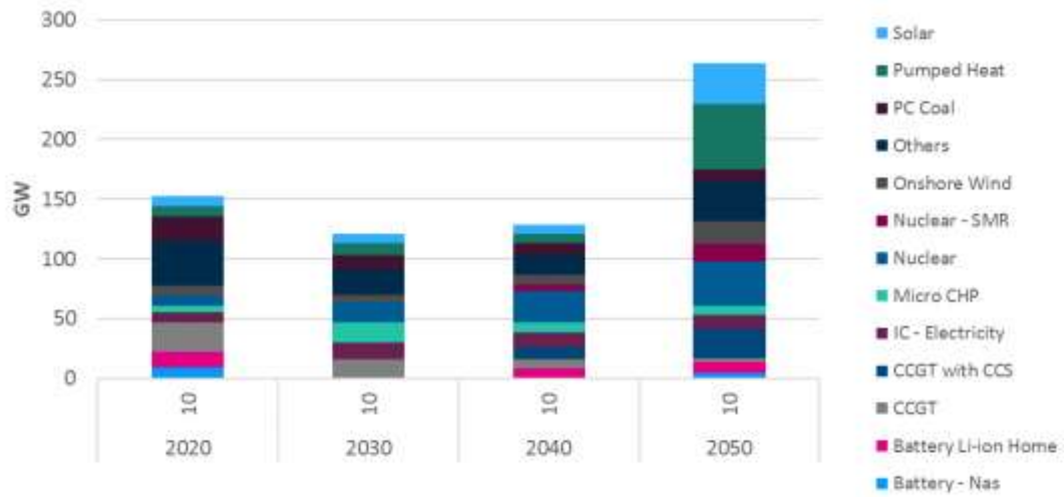
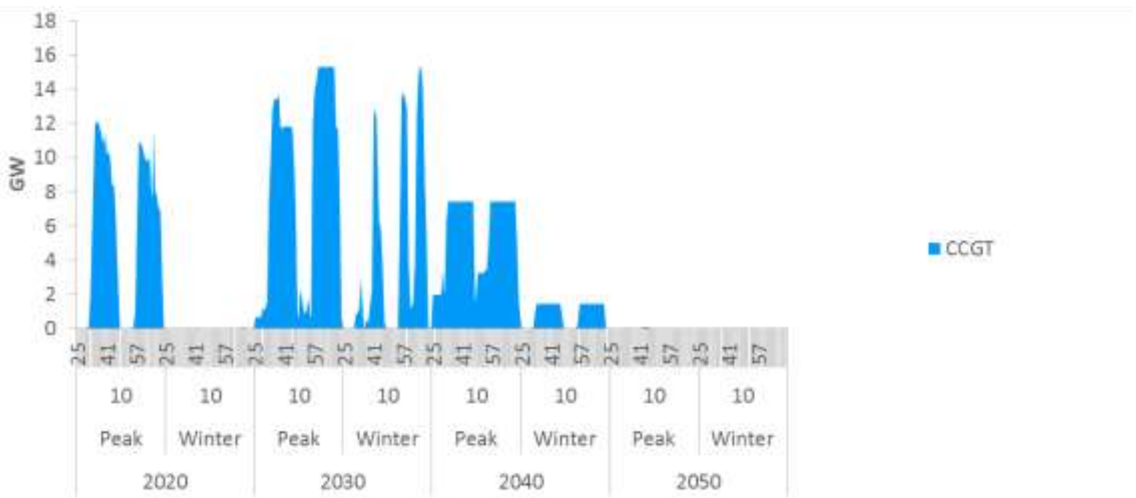


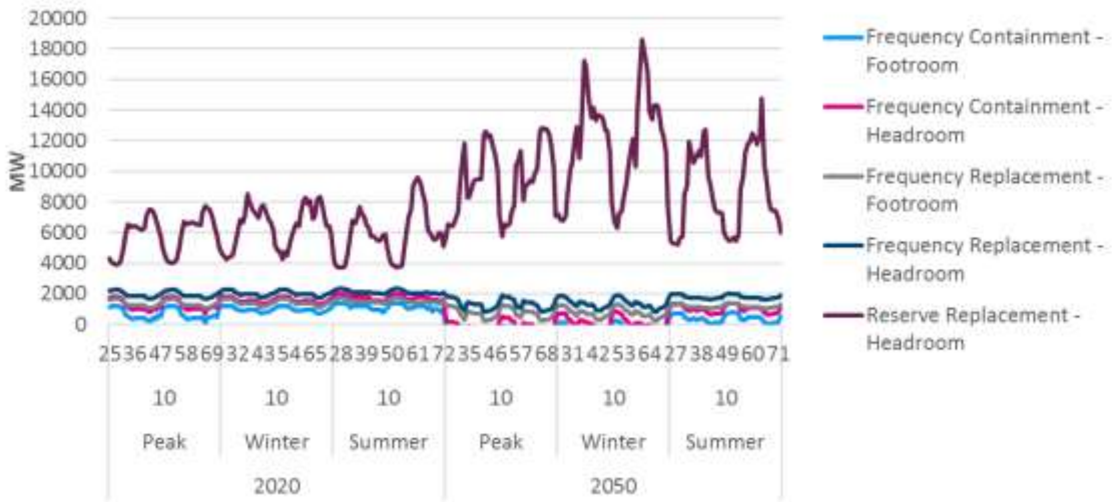
Figure 33 CCGT dispatch, 48 hours at Peak and Winter, 2020-2050, Base



The requirement and provision of system services is calculated endogenously in the STM. Figure 34 shows the requirement in 2020 and 2050. The additional requirements for dedicated Frequency Containment and Replacement services are heavily dependent on the amount of inertia on the system. Where the inertia is high the system is more resilient to instantaneous changes to supply and demand, and so the requirement for frequency services is lower. It can be seen that in Peak and Winter periods the requirement is lower than in Summer, due to higher inertia from both demand and generation technologies. In 2050 the increase in electricity demand, and the additional inertia provided by large Nuclear plants, result in lower frequency service requirements, with Frequency Containment showing a requirement of 0MW in some periods.

The Reserve requirement increases from 2020 to 2050, due to increases in electricity demand and intermittent renewable generation (both of which have uncertainties that are managed through Reserve services). The reserve requirement is higher in the Winter week than the Peak week due to higher renewable generation output and has a clear diurnal shape in all periods due to the profile of demand. Movements in Reserve and Frequency service requirements are somewhat opposite, due to the demand term. High demand increases the demand uncertainty that Reserve services balance, but high demand also increases inertia (from both demand and generation) that reduces the need for Frequency services.

Figure 34 System service requirement, 2020 & 2050, Base



Electricity storage is included in the capacities shown in Figure 32, but is shown in isolation in Figure 35 (capacity, GW) and Figure 36 (volume, GWh). While the capacities are relatively low compared with the rest of the electricity system, they are large compared with current capacities and with those in the ESME 4.1 results (~7GW, 52GWh in 2050). The SFM has a far more granular representation of the operational requirements of the energy system, and this results in increased capacities of highly flexible storage technologies.

The capacities shown for 2020 are large compared with current capacities, and it may be questioned as to whether these can be built in such volumes by 2020. In the current dataset there are no build rate constraints for any battery technology, which may be resulting in unrealistic capacities in the near term. In the long term however, the small capacity of batteries deployed by the model seems reasonable.

Figure 35 Electricity storage capacity (GW), Base

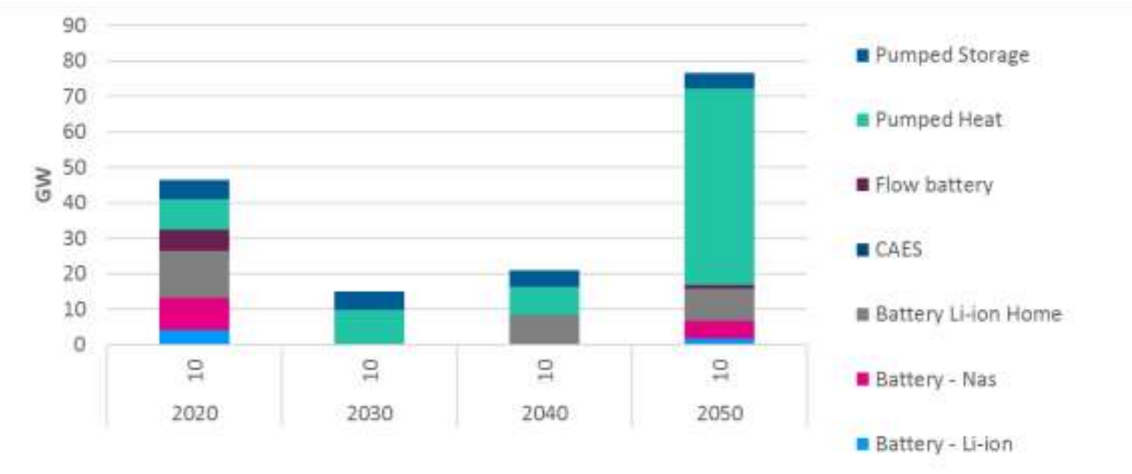
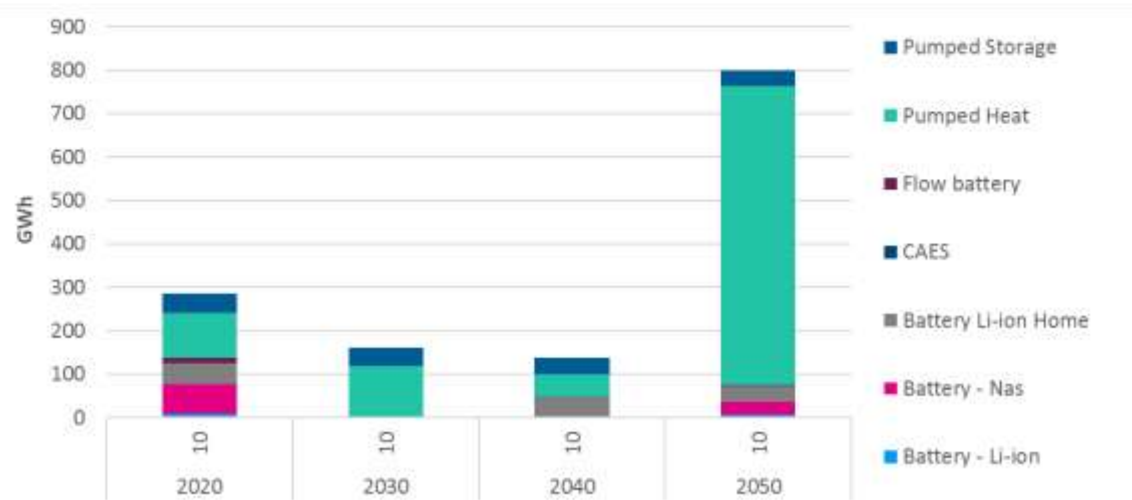


Figure 36 Electricity storage volume (GWh), Base



Electricity storage is used for 3 purposes:

- Demand smoothing (particularly at peak)
  - SFM has a more detailed representation of "Peak" periods, intermittent demand and supply, and dynamic operational constraints that limit conventional generation from balancing this
  - ~50% of storage capacity is used to smooth demand
- System services
  - SFM includes an endogenous calculation of the requirement and provision of system service to cover short term balancing
  - ~25% of storage capacity is used to provide system services

- Extra capacity to cover the system design standard
  - This is assumed to be 1.15%, consistent with ESME 4.1
  - Electrical storage is one of the cheapest ways of adding MW capacity
  - ~25% of storage capacity is used to meet design standard

In the near term a mix of storage technologies is seen:

- **Flow batteries** primarily provide Frequency Containment services, due to their low cost but relatively low round trip efficiency (which reduces their competitiveness for demand smoothing) and have limited storage volume (GWh) for this short duration service.
- **NaS batteries** have a slightly higher efficiency than flow batteries. They are used for system services in most periods, though have a large storage volume (GWh) that make them suitable for a wider range of services. In peak periods they provide small volumes peak load reduction and extra capacity for the HV distribution network that they are assumed to connect to.
- **Li-Ion Home batteries** have high efficiency and are primarily used for peak load reduction and extra capacity for the LV distribution network that they connect to.
- **Pumped Heat** is a relatively low cost storage technology, that has an efficiency similar to NaS batteries, and is similarly used for a range of system services and for limited peak load reduction, though for the Transmission network where pumped heat is assumed to connect to.
- **Pumped Storage** is an existing technology that is used for Frequency replacement in off-peak periods, and for reduction of net load for the Transmission network in peak periods. It is not used for Frequency Containment due to its relatively slow response time compared with the other storage technologies above.

Figure 37 Electricity storage dispatch, 48 hours at Peak and Summer, 2020 + 2050, Base

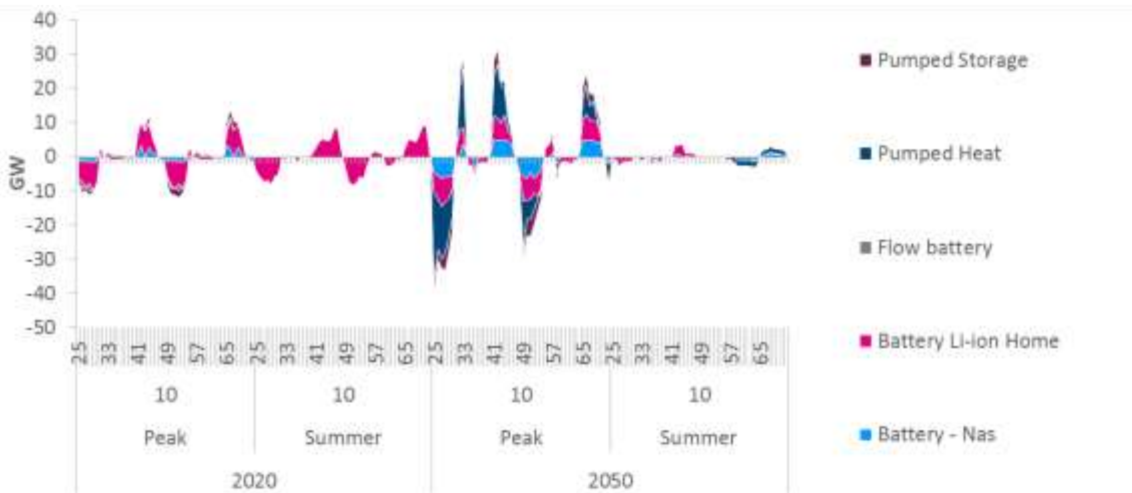
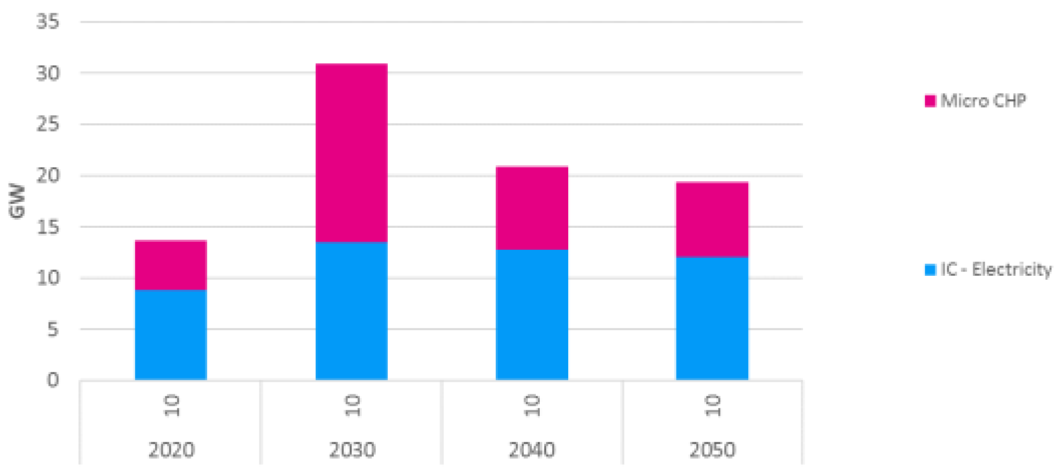


Figure 37 shows the dispatch of these storage technologies in 2020 and 2050 for wholesale energy balancing. It can be seen that in 2020 Li-Ion Home batteries are primarily used for demand smoothing in the wholesale energy market, while other storage technologies only contribute smoothing in a few peak periods, being used for system services in other periods.

In the long term storage capacity is dominated by Pumped Heat, as seen in Figure 35 and Figure 36. . Pumped Heat in 2050 primarily provides a relatively low cost way of providing peak capacity on the Transmission network and meeting the design standard headroom. Frequency services requirements are reduced by 2050 due to increased inertia, and Pumped Heat capacity more than covers this, reducing the need for Flow battery technologies seen in 2020. Despite peak electricity demand increasing significantly by 2050, Li-Ion Home and NaS batteries reduce in capacity. This is partly due to the reduction in Frequency requirements, and partly due to competition from other demand smoothing Distribution network technologies, in particular Building Heat storage and electric vehicles – providing electricity demand smoothing from multiple connected energy vectors.

An interesting result from Figure 35 is that electrical storage is built in the near term but then retired in 2030. The reason for this is the availability of other sources of flexibility in each year. In 2030 there is a large increase in the assumed capacity of electrical interconnector capacity (+ ~5GW, an exogenous assumption) and Micro CHP (built in the SFM due to assumptions around cost reductions for this technology) as shown in Figure 38. The SFM calculates the Peak Contribution Factor (PCF) of each technology based on detailed operation in the STM, and it is found that both of these technologies have high PCFs. However, without this flexible capacity in 2020, other technologies are required. Due to the short economic and technical lifetime of battery storage technologies, they provide a relatively cheap way to build Peak capacity for a single decade, despite their relatively low PCF values as modelled in the STM. In 2020 battery storage provides a "quick fix" for Peak load capacity requirements, which is not needed in 2030. In 2030 Interconnectors replace grid scale batteries while Micro CHPs replace behind-the-meter Li-Ion Home batteries. Were battery storage technologies limited by build rate constraints it is likely that other low £/kW technologies (e.g. OCGTs) would be built in 2020 in their place.

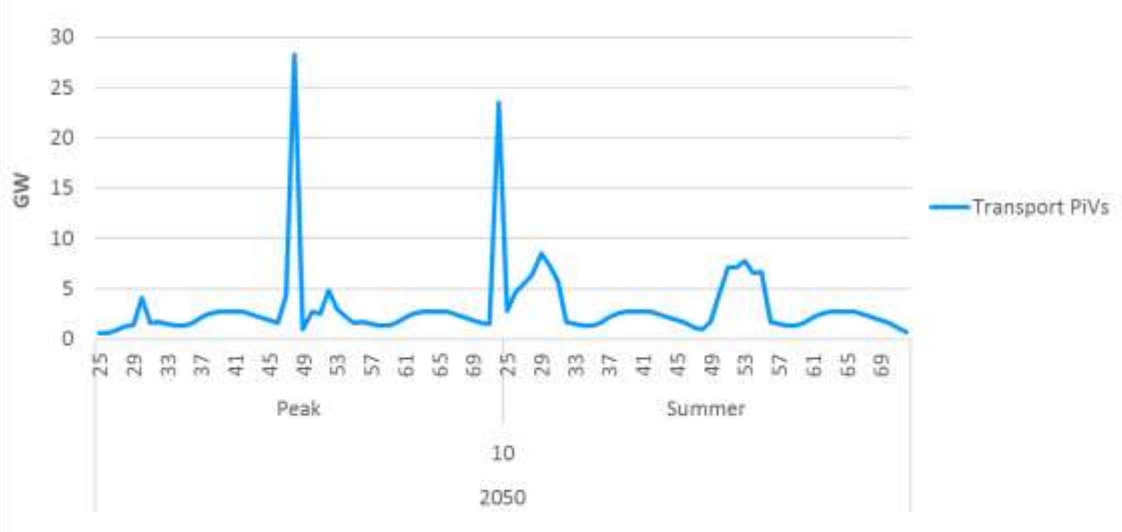
Figure 38 Flexible electricity capacity, Interconnectors and Micro CHP, Base



[

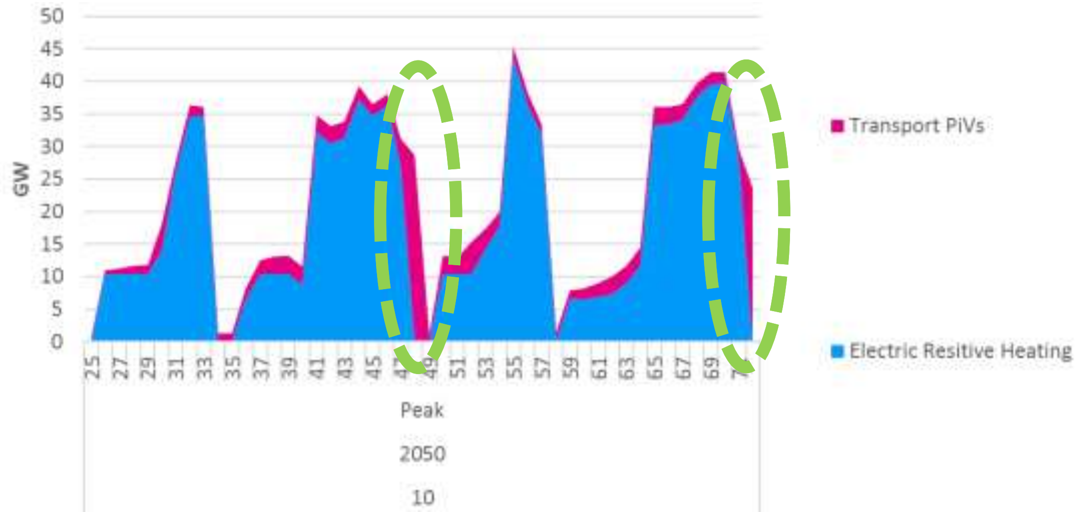
Other than generation, storage and interconnection, another form of flexibility is available to the electricity system through the form of DSR. As an example, a proportion of Electric Vehicles (plug in electric hybrids and fully electric) are assumed to be managed by a central operator for their overnight charging requirements. Figure 39 shows the charging profile of EVs in 2050. During the day the profile is not managed, and follows a smooth demand led pattern. Overnight, however, 50% of EVs are assumed to be centrally managed, with a charging profile that fluctuates to balance supply and demand for the benefit of the system. It can be seen that there is significant demand in the middle of the night, including some large demand spikes during the Peak week, due to managed charging of EVs shifting demand from the evening peak.

Figure 39 EV charging profile, 48 hours at Peak and Summer, 2050, Base



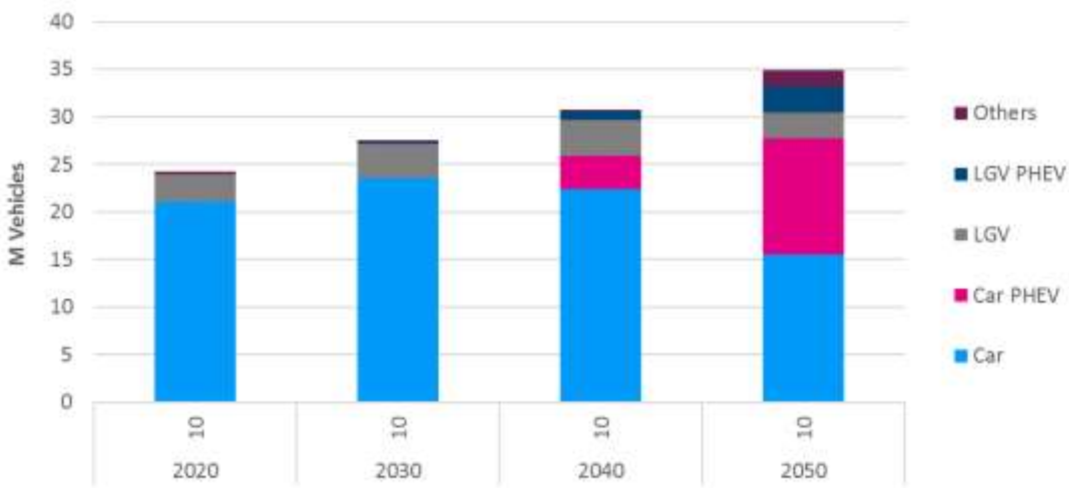
The cause of this spike in EV charging is the reduction in electricity demand for heat, as shown in Figure 40. While heat demand is high in the evening the SFM limits EV charging but uses the short overnight period of low heat demand to charge those EVs that are assumed to be under managed charging.

Figure 40 Electric Resistive Heating and EV demand, 48 hours at Peak, 2050, Base



Electric Vehicles (mainly PHEVs) are built in significant volumes towards the end of the pathway, as shown in Figure 41. Electric vehicles provide a route to decarbonising the transport sector, but significantly increase demand in the electricity sector. The increased representation of operational requirements in the SFM (when compared with ESME 4.1) and the ability of a proportion of EVs to provide flexibility through managed charging, results in significantly higher EV numbers than in the ESME 4.1 results (higher numbers of EVs are observed even though the need to decarbonise the transport sector is reduced in these results, due to the error in input assumptions affecting ICE vehicles, described in Section 3.1.1.1)

Figure 41 Transport capacity over pathway, Base



3.3.1.5 Conclusions

The SFM results above are subject to the caveats outlined in Section 3.1.1, however they provide a self-consistent set of results which show the depth of insights that can come from the SFM. In this report we have selected a small subset of results which demonstrate some of the most interesting features of the SFM 1.1 Base scenario:

1. There is likely to be a significantly increased role for energy storage by 2050
    a. Particularly building level heat storage, used to smooth electrified heat production and decouple the electricity sector from high intra-day heat demand variation
    b. High volumes of electrical storage, predominantly longer duration Pumped Heat, used for peak load reduction and to balance increasing Reserve requirements
2. Flexibility can "flow" across energy vectors, which is key to how technologies are operated
    a. Heat storage flexibility used to run ASHPs in fully utilised baseload operation – reducing LCOE of the heat system and smoothing the demand on the electricity system
    b. Electric vehicles increase total demand on the electricity system but provide flexibility (through managed charging) to balance electricity supply and demand in a way that inflexible Nuclear generation cannot
3. All forms of flexibility compete with one another under the SFMs least cost optimisation
    a. Interconnectors and Micro CHP capacity in 2030 replaces the need for short term electricity storage from batteries in 2020
    b. EVs with managed charging reduce the need for additional flexibility in the electricity sector
4. System service requirements are unlikely to be a driver for capacity expansion of storage or other technologies
    a. Frequency services likely to decrease due to increasing inertia from Nuclear generation
    b. Reserve requirements likely to rise due to increases in electricity demand (electrification of heat and transport) and intermittent generation, but generation and storage capacity built predominantly to cover Peak load likely to be sufficient to cover Reserve requirements
5. New gas storage capacity is unlikely to be required, as gas supply gradually reduces due to decarbonisation in heat and electricity sectors
    a. Existing gas storage capacity more than sufficient to soak up potential increased variability in gas supply coming from intermittent electricity generation

3.3.2 No CCS Scenario

Under the No CCS scenario all CCS technologies are removed. This makes decarbonisation across all sectors more difficult as emissions from conventional fossil fuel fired supply cannot be abated through CCS, nor offset using negative emissions from Biomass with CCS. A distinction is made between "Carbon Capture" and "Carbon Capture with Transport and Storage" – a limited volume of CO_2 is required for industrial processes, and this is allowed to be captured from fossil fuel processes, though without any CO_2 storage or transportation facilities (i.e. captured CO_2 must be used on-site for industrial processes). In this section the differences between the No CCS and Base scenarios are explored, focussing on how the capacity of technologies built changes in this scenario, and the impact on flexibility requirements and flexible technology operation.

3.3.2.1 Heat

Under the No CCS scenario, the heat sector is not materially changed from the Base scenario. Figure 42 shows the supply of heat under the No CCS scenario. At a high level the supply of heat is broadly similar to the Base Scenario, with a switch from Gas Boilers to ASHPs and electric resistive heating.

However, the capacity of heat supply technologies shows some differences, as shown in Figure 43. In the No CCS scenario there are higher volumes of domestic heat storage for hot water by 2050 (+28GW). One might expect space heat storage to be more useful to the system, given the large variation in space heat demand, but in both the Base and No CCS scenario the build quantity constraints for domestic space heat storage are met and so no more can be built. Without the ability to build storage for space heat the SFM chooses to build extra flexible storage capacity for hot water, hot water storage being subject to a separate build quantity constraint from space heat storage (as per the ESME assumptions). Another difference between the No CCS and Base scenario is a small reduction in the capacity of ASHPs.

Figure 42 Heat supply, annual, 2020-2050, No CCS

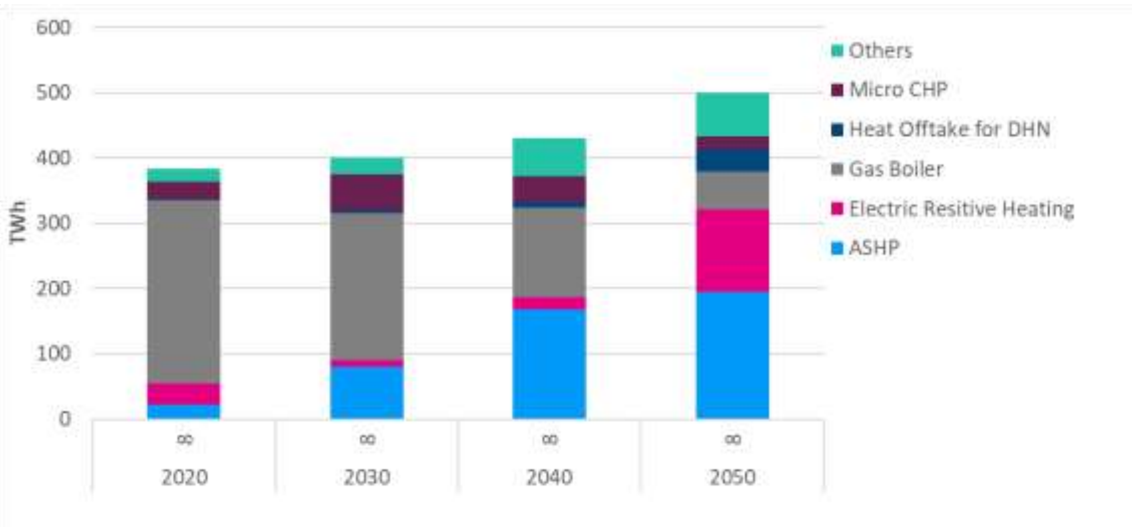
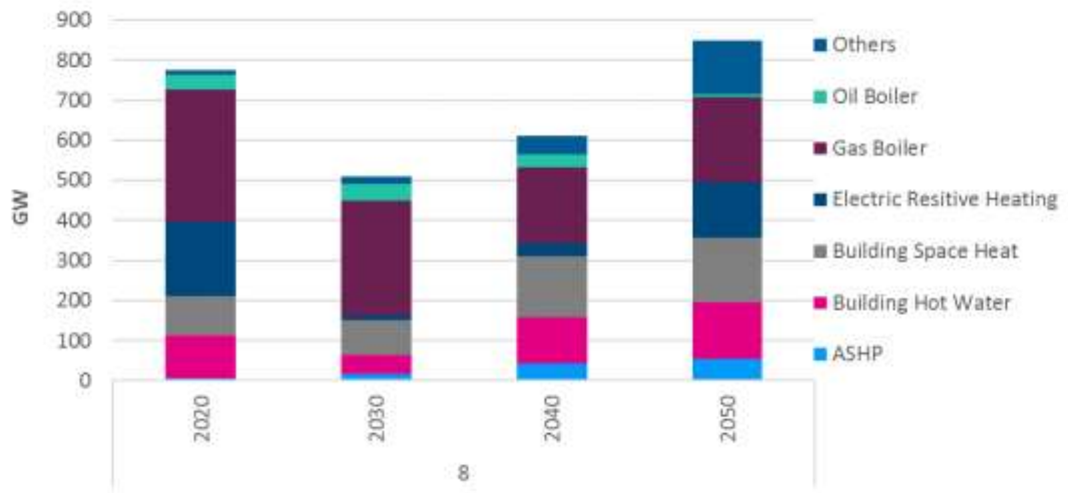


Figure 43 Heat capacity, 2020-2050, No CCS



The additional capacity of storage for hot water allows ASHPs to operate in a manner even closer to baseload than in the Base case, as shown in Figure 44 and Figure 45. By increasing the level of storage in the heat sector this smooths the profile of electrified heat, requiring a reduced capacity of ASHPs and smoothing the demand for electricity coming from electrified heat. This further decoupling of the demand swings seen in the heat sector from the electricity generation sector is needed in the No CCS due to the removal of low carbon flexible electricity generation technologies (i.e. CCGT with CCS).

Figure 44 ASHP supply, 48 hours at Peak and Winter, 2050, No CCS

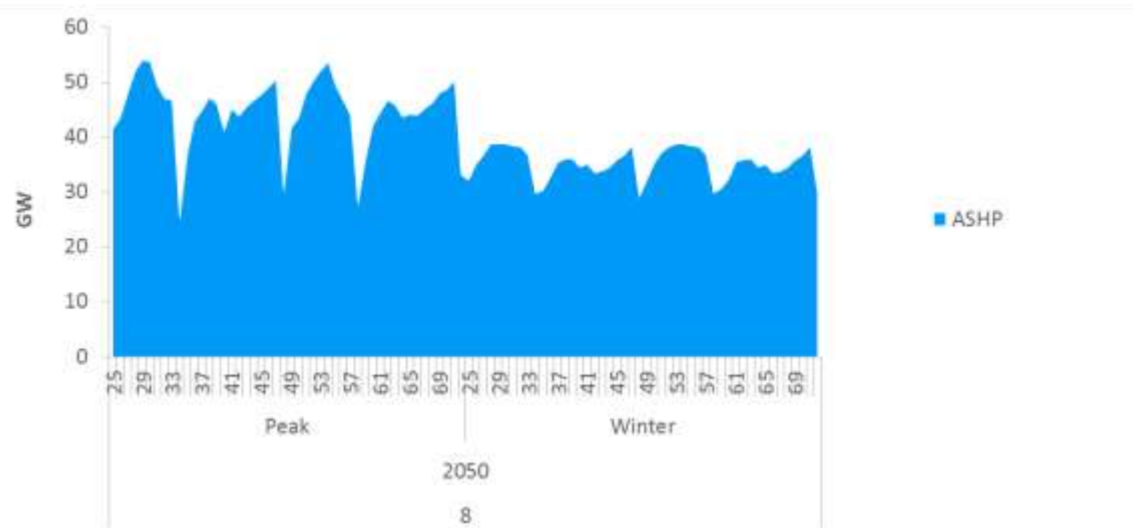
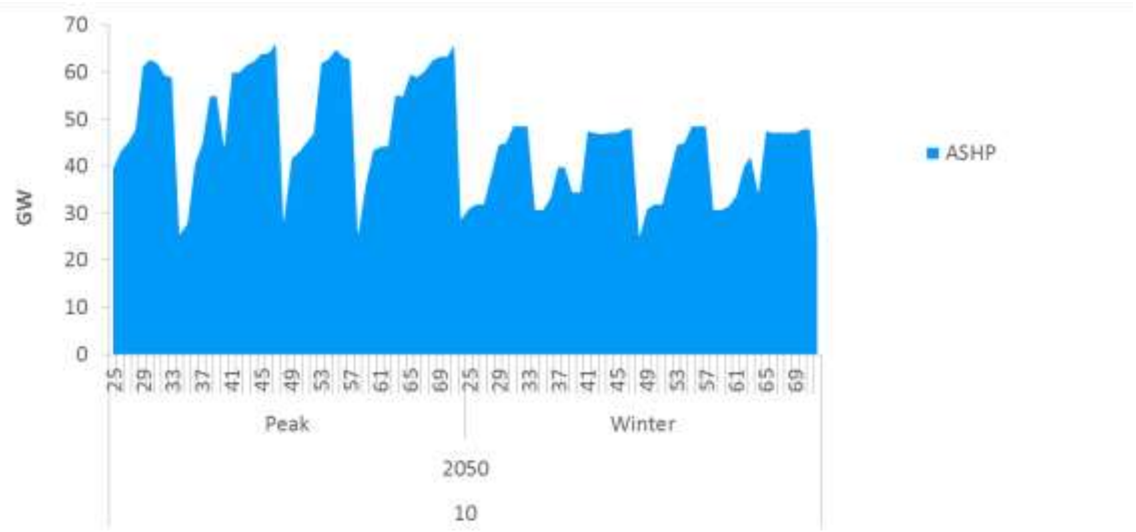


Figure 45 ASHP supply, 48 hours at Peak and Winter, 2050, Base



3.3.2.2 Gas/H2

Gas consumption is directly affected by the removal of CCS technologies, as the model cannot use Gas CCGTs with CCS for electricity generation, nor for industrial CCS, which provide a key route to decarbonisation in the Base scenario.

Figure 46 and Figure 47 show the consumption and supply capacity of Gas and Hydrogen across the pathway. Gas consumption in later years is significantly lower in the No CCS Scenario, primarily due to a lack of availability of CCGT with CCS technologies. Supply capacity is broadly unchanged over the pathway, consistent with the Base Scenario, though there is some Power to SNG and Hydrogen electrolysis capacity in 2050 that provides a limited amount of low carbon gaseous fuel for use in all sectors in the No CCS Scenario, shown in Figure 48. SNG is produced using CO_2 captured onsite as the waste product of electricity generation processes and some fossil fuel based hydrogen production processes. While CO_2 cannot be stored in the No CCS scenario, by using SNG it can be converted to Gas, which can be stored and transported using the existing Gas infrastructure. The production of SNG allows excess electricity in Summer periods (from solar generation) be converted into a seasonally storable energy vector, which can used in Winter months with near zero net carbon emissions.

Figure 46 Gas / H_2 consumption, annual volume, No CCS

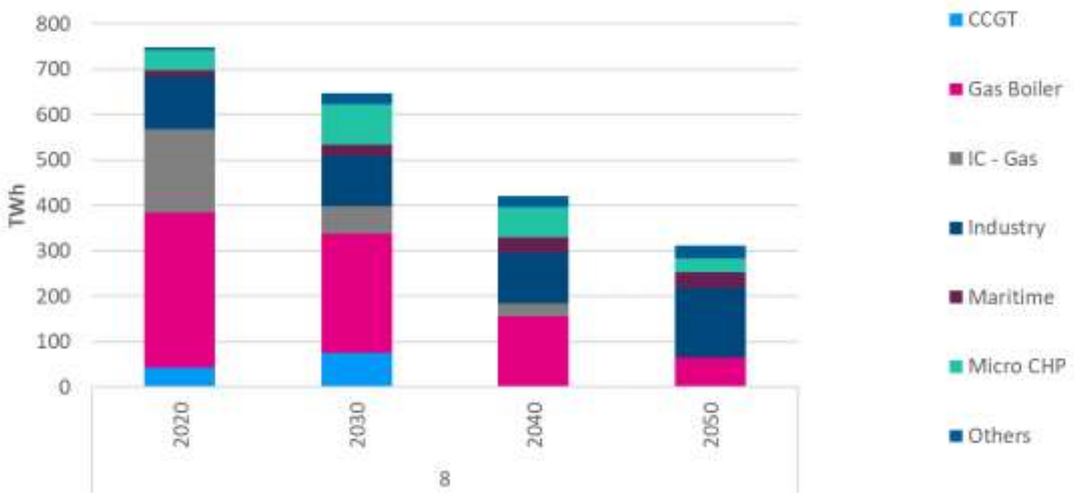


Figure 47 Gas / H2 supply capacity, No CCS

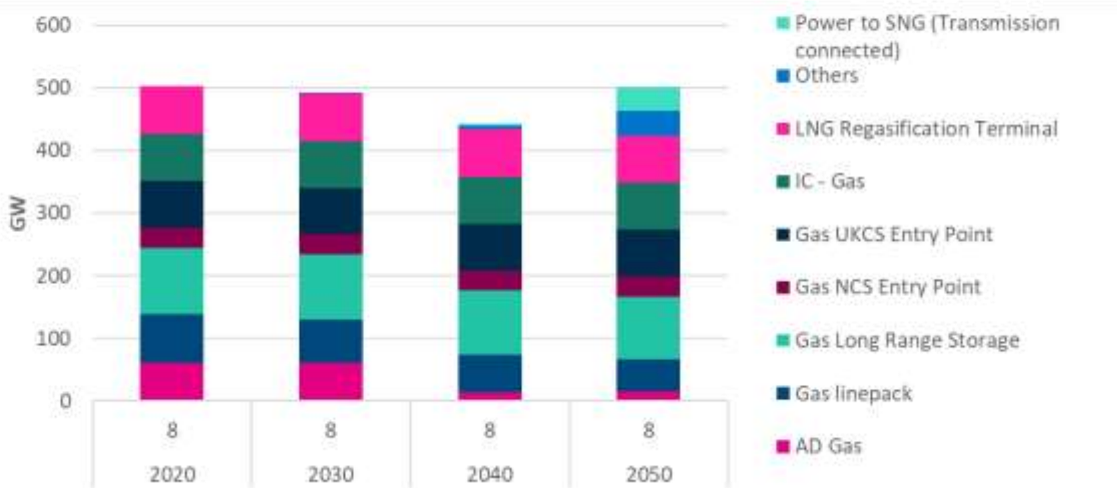
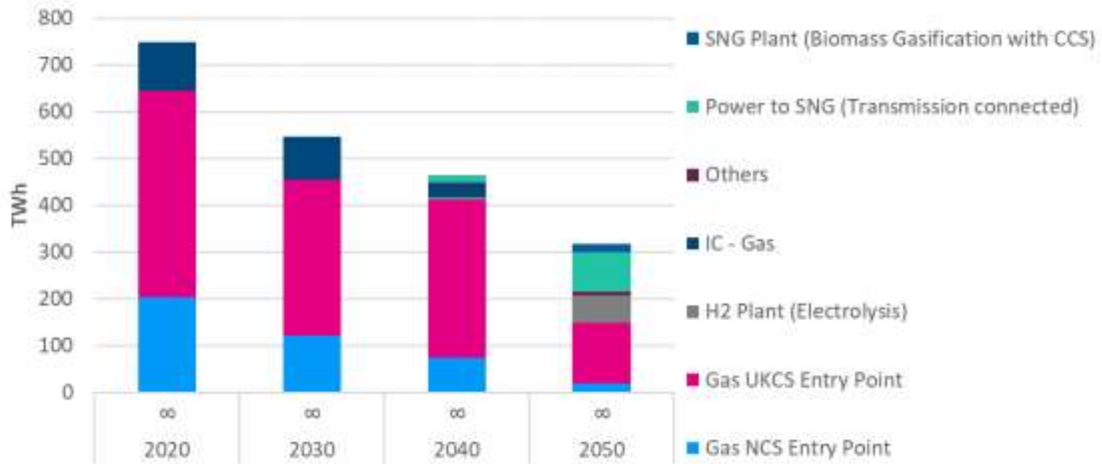
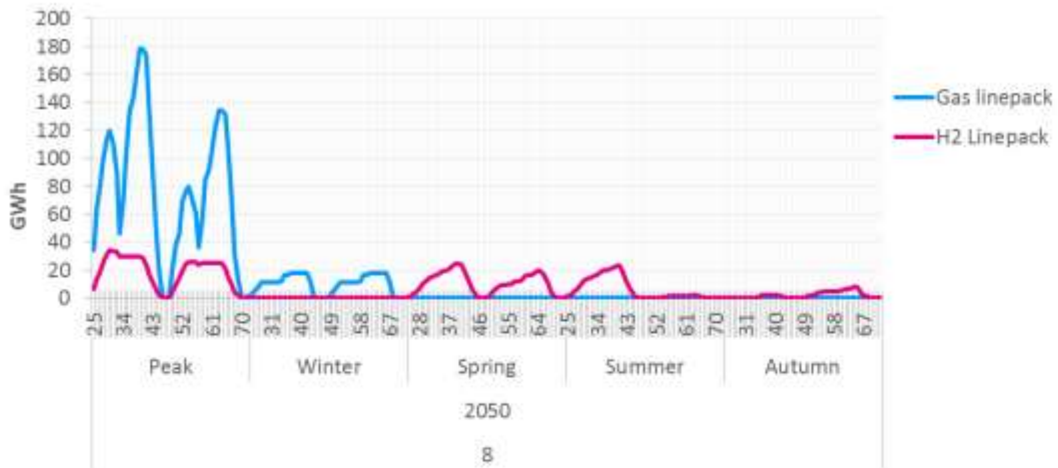


Figure 48 Gas/H_2 supply, annual volume, No CCS



In the No CCS scenario significant volumes of hydrogen are produced, transported, and consumed over a newly built hydrogen network. The network itself contains storage potential, through "linepack" functionality (adjusting the pressure of the network). Figure 49 shows the hourly linepack volumes for Gas and H_2 networks respectively. While the Gas network uses linepack storage to smooth peak demand in winter months only, the H_2 network uses linepack to smooth both peak demand (Peak week) and peak supply (Spring, Summer, and Autumn, when solar electricity generation is high and can be used for electrolysis).

Figure 49 Gas and H_2 linepack volumes, 48 hours, 2050, No CCS



3.3.2.3 Electricity

The electricity sector shows significant difference under the No CCS scenario, as zero (or negative) carbon CCS technologies are made unavailable. Figure 50 and 51 show the annual electricity supply and generation capacity respectively.

Capacity in 2050 is increased substantially in the No CCS Scenario, from 260GW to 520GW, as large volumes of low load factor renewables (solar, 94GW; onshore wind, 20GW; offshore wind, 96GW) are built in place of CCS technologies for low carbon electricity. Large scale nuclear capacity is limited by build quantity assumptions, and so is identical in the No CCS and Base scenario, but an additional 5GW of Nuclear SMR capacity is built in the No CCS scenario.

Supply of Electricity is increased by ~300TWh per year in 2050. A large portion of this extra demand comes from the production of SNG and H_2 (~135TWh), confined to the Spring, Summer and Autumn when Solar output provides ample electricity supply, as shown in Figure 52. Increased demand is also seen due to the increased electrification of heat and transport in the No CCS case. In Winter Hydrogen demand is met using fossil fuel based production methods alone, electrolysers being avoided due to high electrified heat demand, as shown in Figure 53.

Figure 50 Electricity supply, annual volume, No CCS

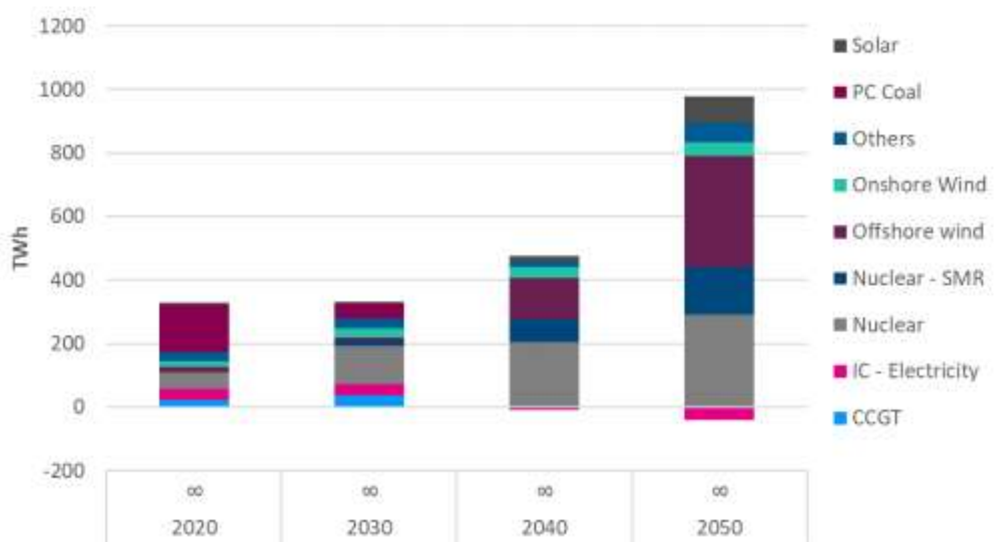


Figure 51 Electricity generation capacity evolution over pathway, No CCS

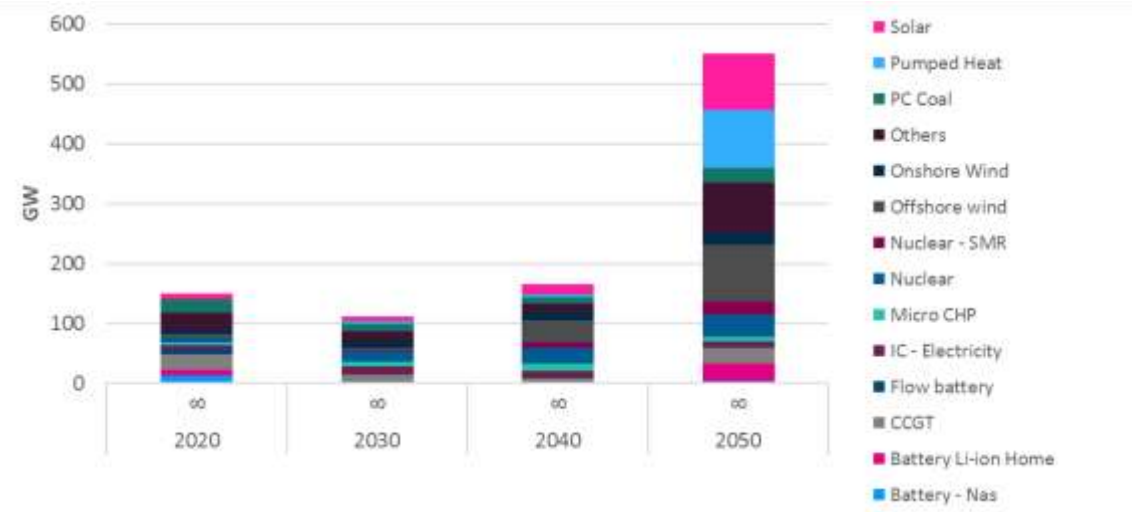


Figure 52 Electricity demand for H2 and SNG production, 48 hours, 2050, No CCS

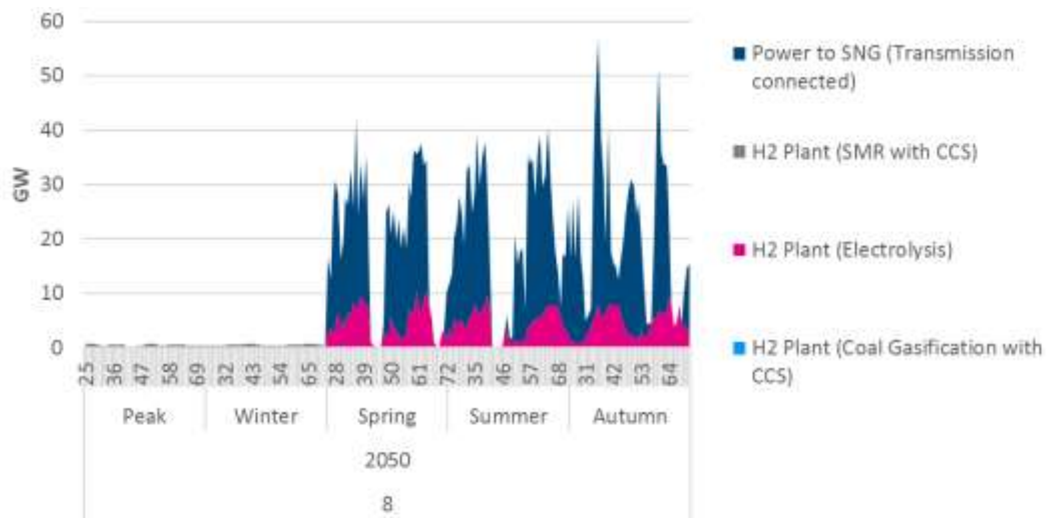
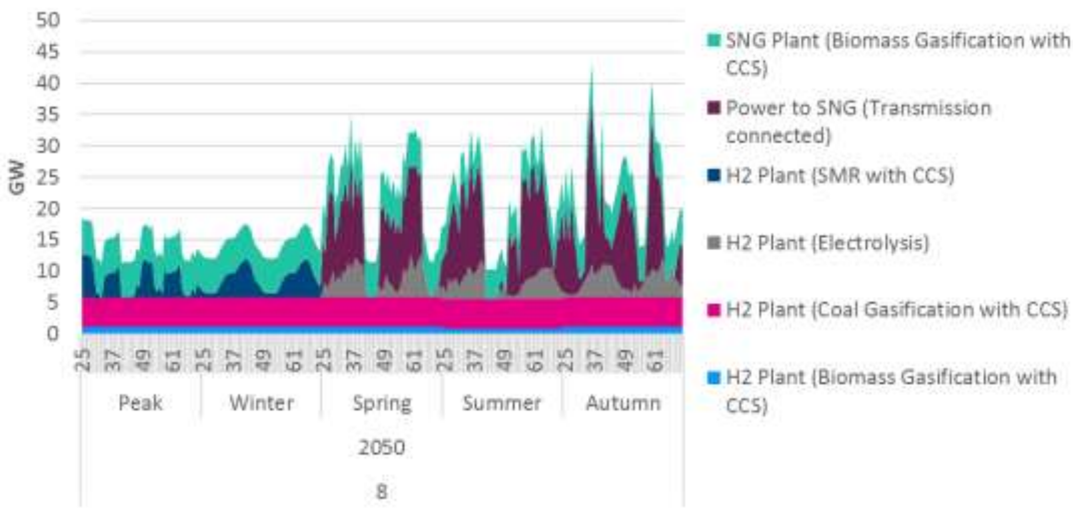


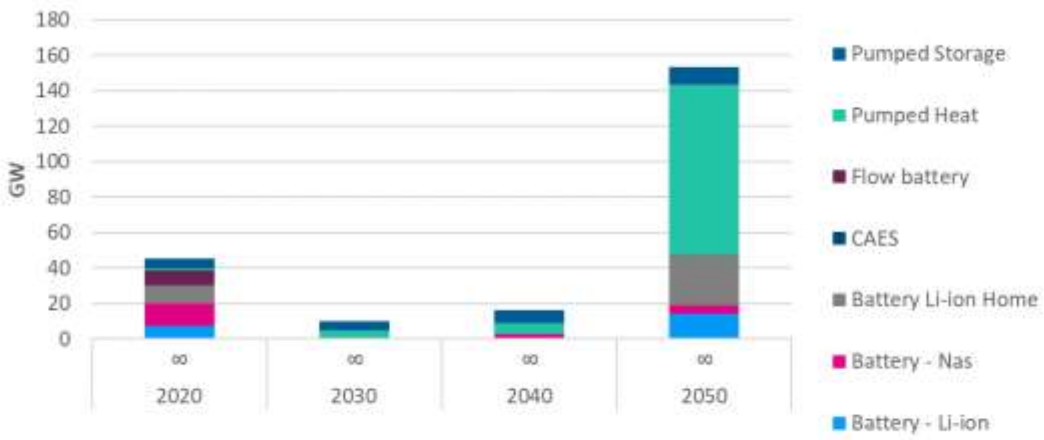
Figure 53   Synthetic gas and H2 production, 48 hours, 2050, No CCS



While annual electricity supply volumes increase substantially in the No CCS case, the peak electricity demand does not (119GW in Base, 123GW in No CCS). This is due to within day demand smoothing provided for by storage technologies in other sectors (increased building hot water storage, increased numbers of EVs) and through seasonal demand smoothing through the production of gaseous fuels (H2 and SNG). Gas is produced in summer months (where there is excess electricity supply) through Power to SNG technology and stored in long range gas storage for use in winter months (reducing the need for electrified heat). Large scale seasonal hydrogen storage is not built in these results (though the SFM has the capability to do so). Seasonal demand for hydrogen is fairly constant –but met partly by electrolysis in summer months and SMR in winter months.

Within the electricity sector itself, electricity storage capacities double in the No CCS case to 150GW, as shown in Figure 54. There is a shift in the mix of electricity storage technologies towards shorter duration batteries (from longer duration pumped storage and pumped heat storage technologies), providing increased flexibility from storage in the face of increased intermittency from renewables and reduced flexibility from CCGTs with CCS. The need for storage capacity is somewhat limited by the flexibility provided by Hydrogen electrolysis plants, which provide intra-day energy balancing and frequency replacement provision when not actively producing H_2.

Figure 54 Storage capacity (electricity), evolution over pathway, No CCS



The requirement for system services changes substantially in the No CCS case, shown in Figure 55. Reserve requirements increase substantially in 2050, due to high output from intermittent wind and solar generation, rising from a peak reserve requirement of 18GW (Base) to 30GW (No CCS). This peak reserve requirement occurs in the Winter, not the Peak week – as in the Peak week wind and solar output are assumed to be very low (one cause of high net demand), and the difference between the Base and No CCS scenarios is therefore higher in the Winter than the Peak week. The breakdown of the Reserve requirement in Summer 2050 is shown in Figure 56, where the large contribution from intermittent generation can be observed. Frequency service requirements are little changed in Winter, with inertia from additional Nuclear SMR plants offsetting the lack of CCGT with CCS. In Summer months, Frequency service requirements are slightly lower in the No CCS case, due to increased demand (and therefore inertia from supply and demand) coming from the production of SNG and H_2.

Figure 55 System service requirement, 2020 & 2050, No CCS

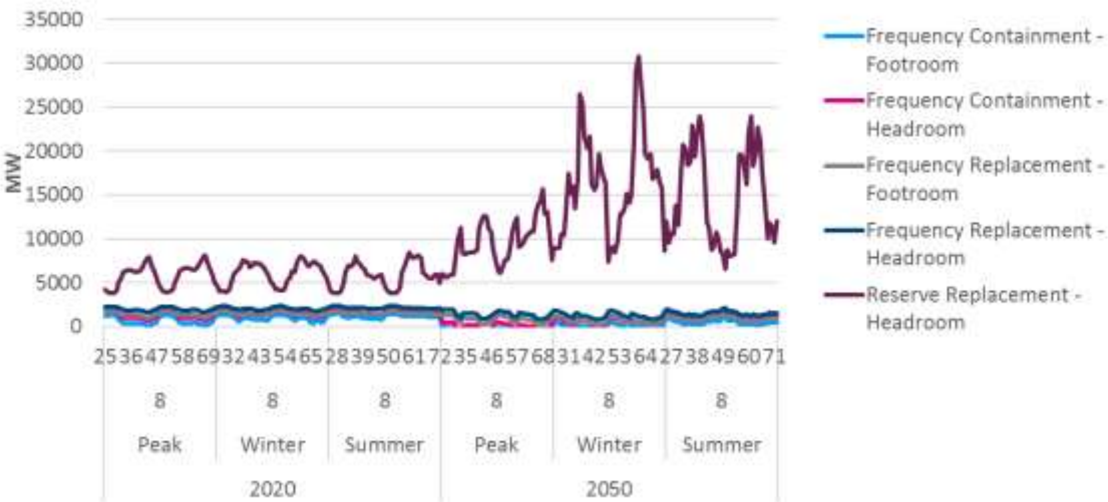
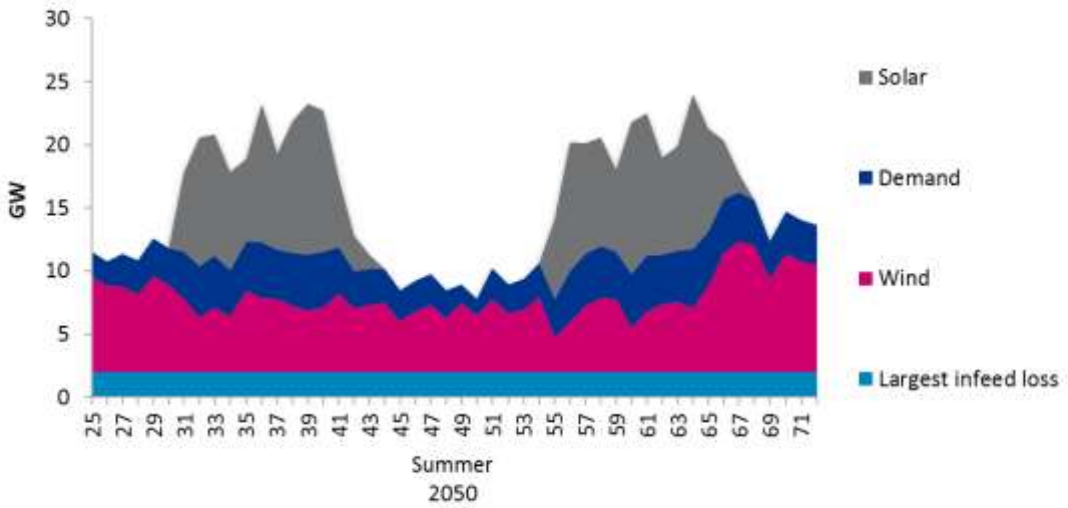


Figure 56 Breakdown of reserve requirements, 48 hours at Summer, 2050, No CCS



To focus on the operation of just one storage technology, Figure 57 shows the energy output of Li-ion home battery storage in 2050. It can be seen that this technology is used at Peak, though only 24GW of the 29GW installed is used at any one time. In Summer this technology is virtually unused for energy balancing.

Figure 58 shows the proportion of Li-ion home battery storage capacity that is committed to system services in 2050. Two variants of the same technology are shown, low duration (2hours) and high duration (6hours). Low duration services are better suited to short duration Frequency Containment services than peak demand smoothing, and so commit a higher proportion of their capacity to this service. Li-ion home batteries cannot commit more than 20% of their capacity on average to energy services at Peak, because the remainder is to be used for peak load smoothing. However, in Summer, where they are not used for energy smoothing they commit close to 100% of their capacity to system services.

Figure 57 Li-Ion Home battery storage dispatch, 48 hours at Peak-Winter-Summer, 2050, No CCS

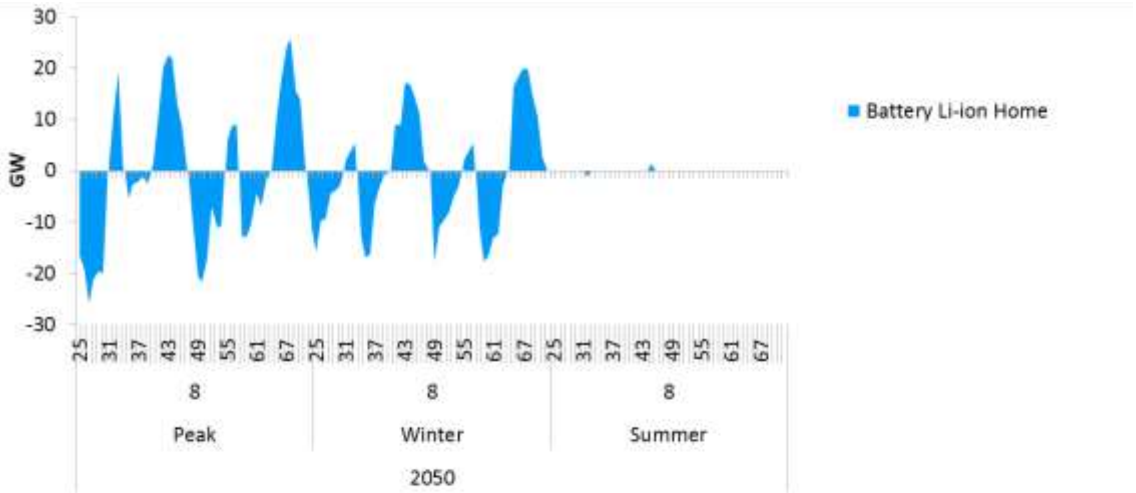
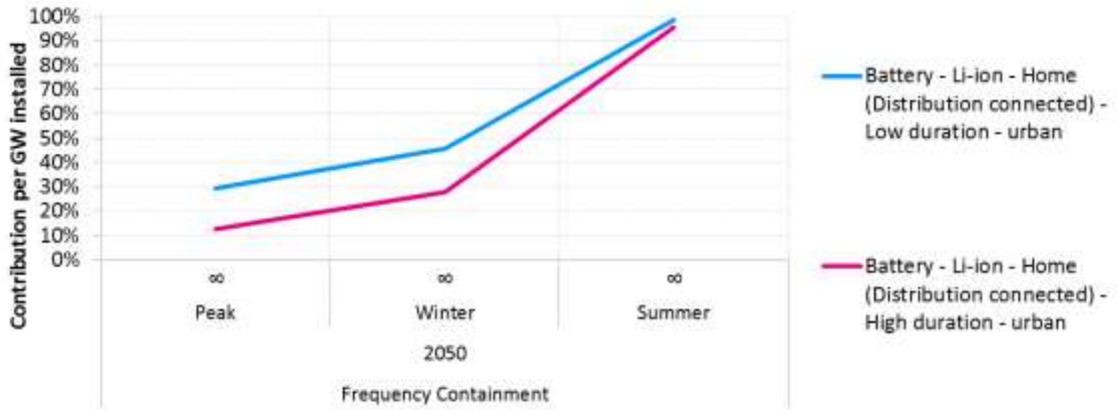
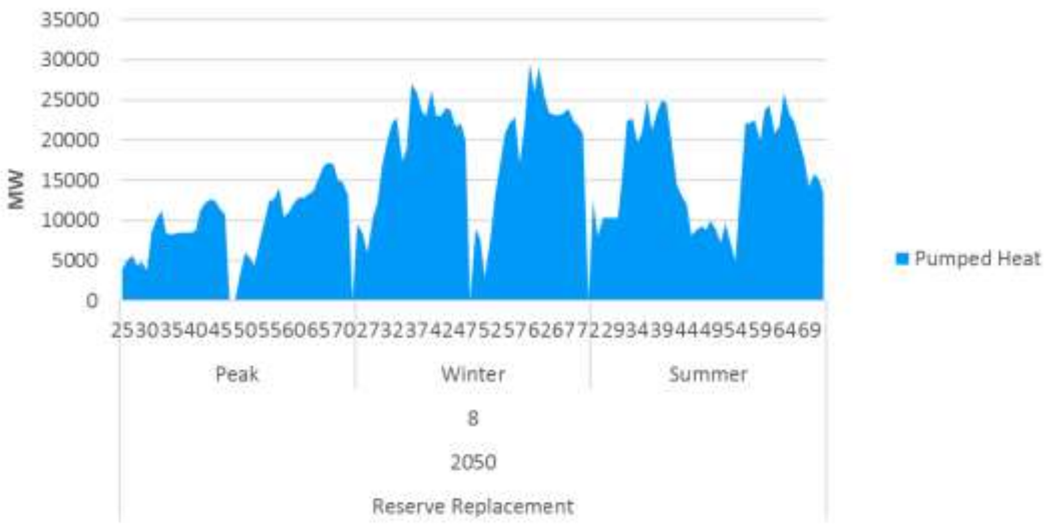


Figure 58 Li-Ion Home battery Freq. Containment provision, Peak-Winter-Summer, 2050, No CCS



Similar observations can be made for all storage technologies. In the No CCS scenario, the large increase in storage capacity for peak load reduction results in excess capacity in most periods that can be used for system services. Pumped Heat storage is used to provide the bulk of the high Reserve Replacement requirement found in the No CCS case, as shown in Figure 59.

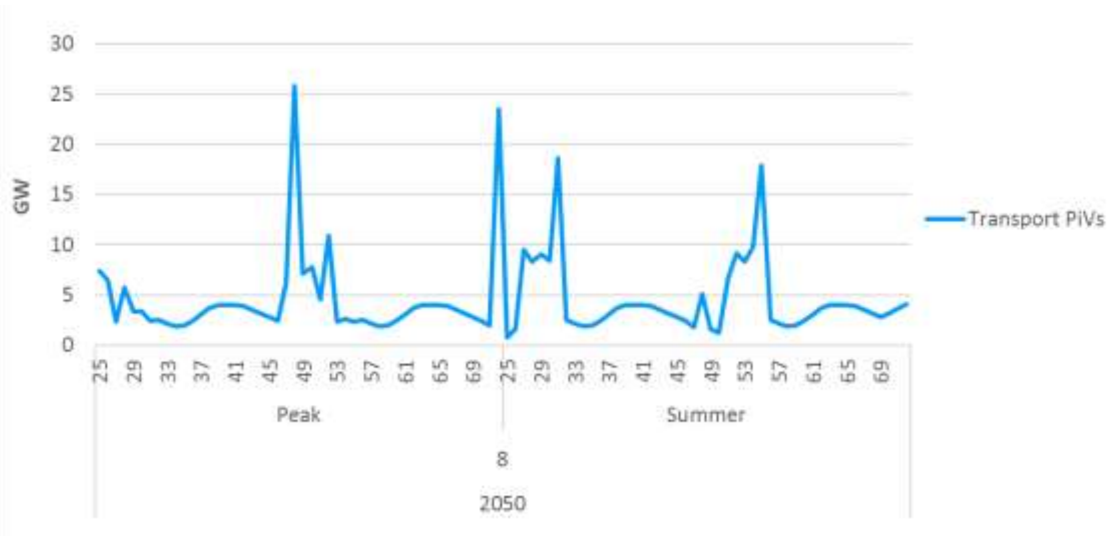
Figure 59 Pumped heat storage Reserve provision, 48 hours Peak-Winter-Summer, 2050, No CCS



In the No CCS scenario there is an increase in electrified transport; by 2050 there are an additional 0.6 million plug-in hybrids vehicles (PHEVs) and 1.5 million battery powered electric vehicles (BEVs) compared with the Base scenario. The increased electrification of transport in the No CCS scenario allows for system wide decarbonisation to be achieved, while ensuring system stability, by substituting the supply side flexibility of CCGTs with CCS technology for the demand side flexibility of EVs with managed charging.

Figure 60 shows the charging profile of EVs in the No CCS scenario. The peak demand from EVs does not increase from the Base scenario, with the increase in total demand from EVs in the No CCS scenario seen in overnight periods away from the EV peak, an example of how the SFM optimises the operation of flexible technologies to reduce system costs.

Figure 60 EV charging profile, 48 hours at Peak and Summer, 2050, No CCS



3.3.2.4 Conclusions

The No CCS scenario makes decarbonisation more difficult across all sectors. Using the SFM to analyse this challenging decarbonisation scenario provides the following insights:

1. Energy demands are further electrified to allow decarbonisation in other sectors, without the option of CCS
    a. Higher electrified heating, primarily through higher utilisation of heat capacity (ASHPs and electric resistive)
    b. Electrified production of gaseous fuels (Gas and H_2)
    c. Higher electrified transport through EVs
2. However, flexibility provided by CCGTs with CCS in the Base scenario is replaced by flexible technologies in all sectors in the No CCS scenario
    a. Additional 28GW of hot water storage capacity in the heat sector by 2050
    b. Electricity storage capacities double to 150GW
    c. Gas network provides sufficient flexibility to soak up excess supply from SNG without increases in capacity, but shows higher utilisation
    d. Higher EV penetration and associated number of vehicles with managed charging
3. Provision of system services remains achievable with capacity built primarily for peak load reduction
    a. Frequency service requirements decrease in No CCS scenario due to very high volumes of high inertia Nuclear generation
    b. Reserve requirements increase significantly, due to increased demand and intermittent generation, however, technologies built primarily as peak load capacity provide sufficient capacity to cover Reserve
4. Higher flexibility requirements result in shorter duration storage technologies
    a. Mix of electricity storage technologies moves from longer duration Pumped Heat technologies to shorter duration Batteries

3.4 Monte-Carlo analysis

3.4.1 Approach

The aim of the Monte Carlo analysis is to evaluate the effect of short term uncertainty on the potential role of storage and sources of flexibility.

The key benefits of performing the Monte-Carlo analysis on short term uncertainties are:

- **The definition through fundamentals of "peak conditions" for the system**: due to the iterative process of the model, the stress of the system is evaluated between STM simulations by looking at the unserved energy in each case. As a result, it is possible to infer the most impactful parameter for a given system design (e.g. wind output should have a greater influence on system stress in systems with heavy penetration of wind energy). This endogenous calculation of peak conditions in the Monte-Carlo analysis is a key difference with the deterministic analysis, where "peak" conditions are defined exogenously from historical data.
- **Assessment of the resilience of the system:** since the stress of the system is assessed for every simulation, once the unserved energy of the worst case will be resolved, the resulting system could be considered resilient with respect to the parameters simulated.

The Monte Carlo analysis has been performed on a reduced scope of the Base Scenario model:

- **Number of STM simulations:** 20. A prior sensitivity analysis has been performed in order to assess the impact of the number of simulations on the sample distribution, especially the effect on extreme cases (P95). Indeed, a low number of simulations is favourable in terms of computation time but can be detrimental to the representation of peak conditions.
- **Pathway**: 2050. A single year has been chosen in this analysis for computational reasons. However, in order to compare the Base Scenario and MC on the same grounds, the installed capacities prior to 2050 are defined as existing based on the Base Scenario results. Therefore, the model still has a wide range of decision variables available but informed by the pre-existing capacities of the Base Scenario. 2050 is the year of maximum capacity change in the Base scenario, and this is free to be re-optimised in the Monte-Carlo run.
- **Seasons**: 4 seasons (Peak excluded). As previously mentioned, one of the goals of the MC analysis is to redefine the peak conditions based on the evaluation of the system stress.
- **Description of the sample:** The parameters sampled are exclusively targeted on the STM, since the aim is to simulate short term uncertainty. The parameters and their impact are:
  - Wind output: Affects the load profile of the different wind turbines. This is based on historical data on wind speeds for different spatial regions of GB. The distribution parameters reflect observed correlation between regions and sequential timeslices.
  - Solar output: Affects the load profile of the different solar technologies. This is based on historic GB data for solar output and reflects correlation across different spatial regions.

- Power plants outages: Affects the availability factor of the power plants. This is based on historic data for plant in GB
- Electricity prices in neighbouring countries: Affects the behaviour of interconnectors. This is based on Baringa's forward looking Pan-EU electricity market modelling, decarbonisation scenario. Price distributions for- and correlations between- markets are calculated for those directly connected to GB.
- Temperature: Affects the building heat demand and the heat pumps COP. This is based on historical data for temperature across spatial regions of GB. The distribution parameters reflect observed correlation between regions.

In addition to the correlation within each type of parameter further correlation coefficients have been specified between:

- Wind output and temperature
- Wind output in GB and electricity prices in interconnected markets

3.4.2 Results

3.4.2.1 Heat

The first observation regarding the heat capacity (Figure 61) in the MC run is a significant increase in the capacity required, while maintaining a similar supply volume (Figure 62). The peak conditions (maximum instantaneous total heat demand for any sim) are similar in the MC run and Base Scenario (Figure 63). However, in the MC run a wide range of simulations are performed with potential local supply constraints in each one due to fluctuations in temperature and generation. When run in MonteCarlo mode the SFM seeks to design a system that reduces the unserved energy in the most stressful simulation (in terms of unserved energy), which can vary each iteration. The evolution of heat capacity over each iteration is shown in Figure 64. The SFM learns to increase capacity across the network at multiple locations to provide a more robust design for a range of short term conditions, and therefore increases capacity versus the deterministic Base scenario, where capacity is optimised for single set of short term assumptions. There is a reduction in the capacity of Gas boilers, though increases in capacity are seen for most other heat supply technologies, which more than compensate for this.

The total annual supply is unchanged, showing that the average demand level in the MC run matches the Base scenario as expected. There is a shift of energy supply from electric resistive heating and gas boilers to Micro-CHP (heat and power production) and ground source heat pumps.

The rationale behind this design choice in the MonteCarlo model is:

- By iteratively selecting the most stressful simulation (in terms of unserved energy) in each coupling iteration, the model is effectively building a better-rounded system fit for the wider range of conditions variations simulated (different vectors stressed, nodes, etc…)

▸ The diversity of system conditions then favours hybrid technologies because of their versatility, where a more niche “single use” technology might struggle with changing system conditions.

Heat pumps are still the baseload heat supply source, but there is more diversity in the supply due to an increase in ground source heat pumps capacity and supply, and a slight decrease in the supply from air source heat pumps. Further diversity of supply comes from micro-CHPs, which compete with gas boilers in Winter periods, as shown in the dispatch chart of Figure 65. Micro-CHP also provides distribution level flexibility to the electricity system, which experiences greater variability of supply and demand in the monte-carlo runs, and so reduces the need for reinforcement of the electrical distribution network.

Figure 61 - Heat Capacity, LTM, 2050, Base vs MonteCarlo

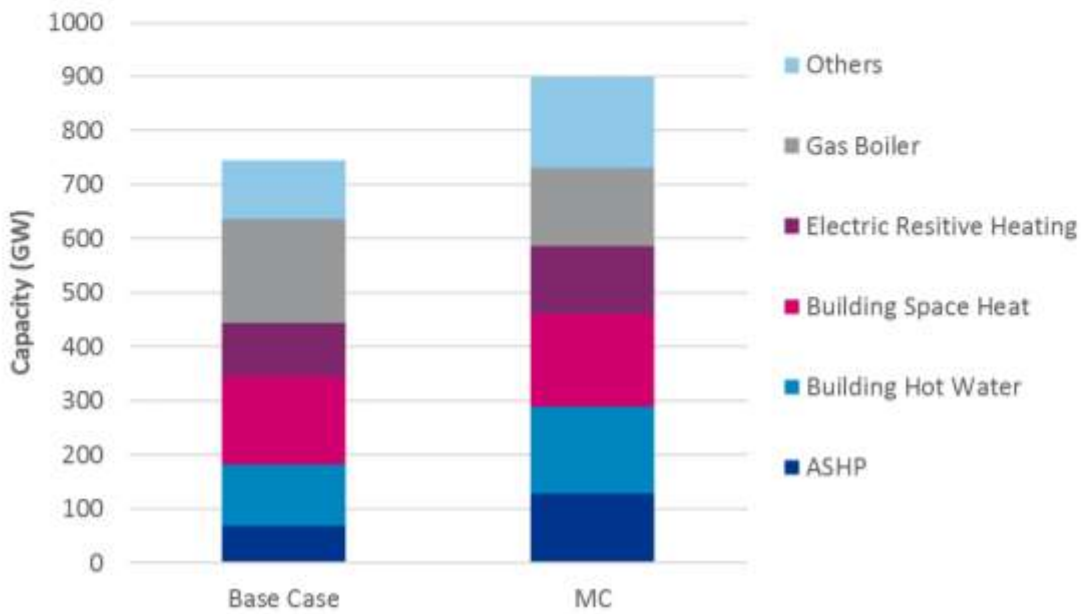


Figure 62 - Heat Supply, LTM, Annual, 2050, Base vs MonteCarlo

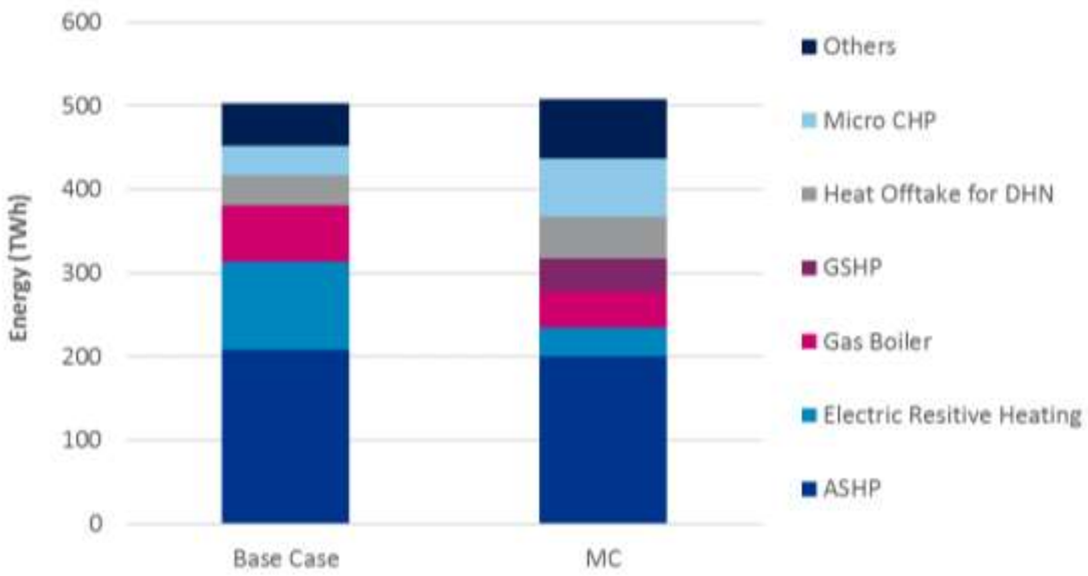


Figure 63 - Heat Demand, Hourly, 2050, Base vs MonteCarlo (most extreme STM sim)

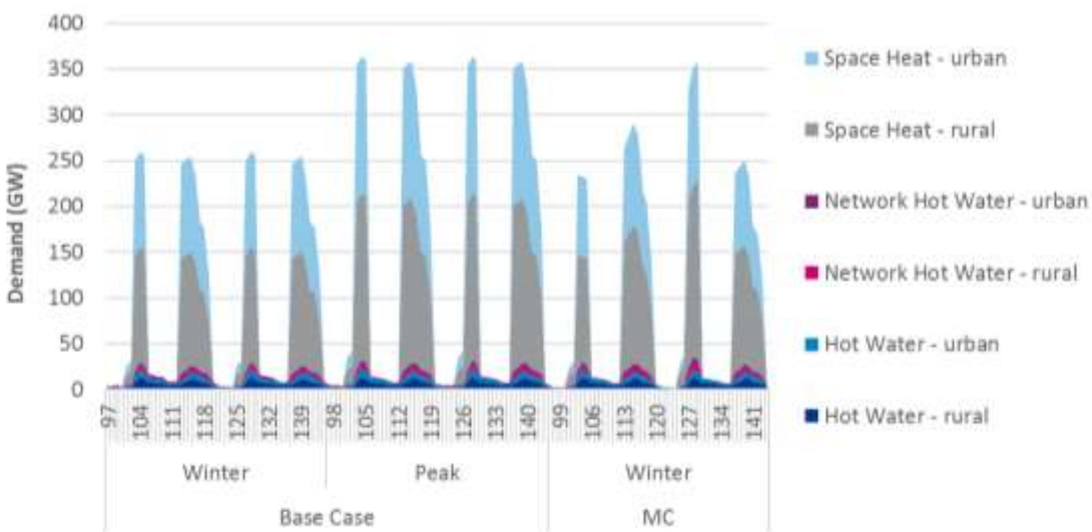


Figure 64 Heat generation capacity evolution over coupling iterations, MonteCarlo

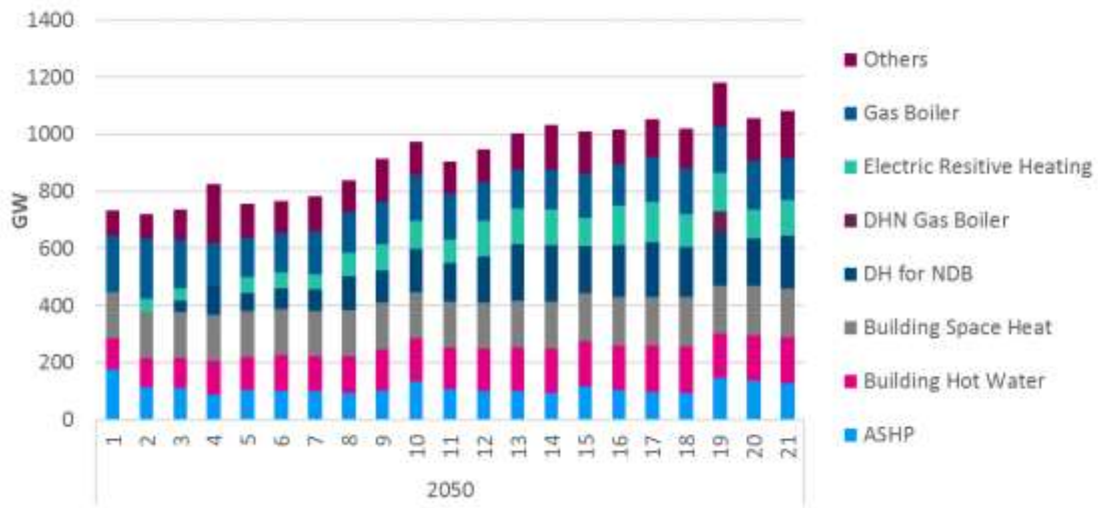
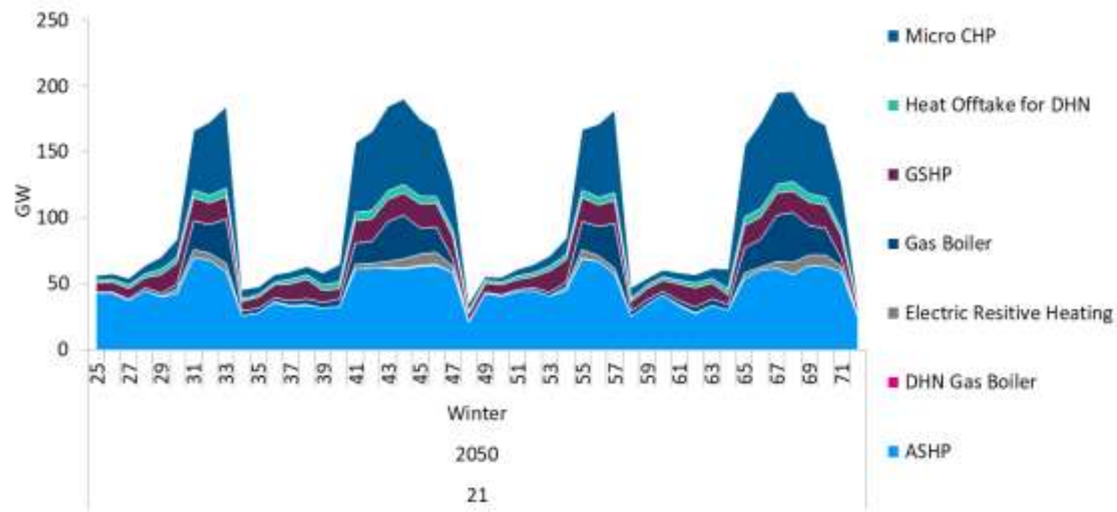


Figure 65 Dispatch of key heat generation technologies, average over 20 sims, MC

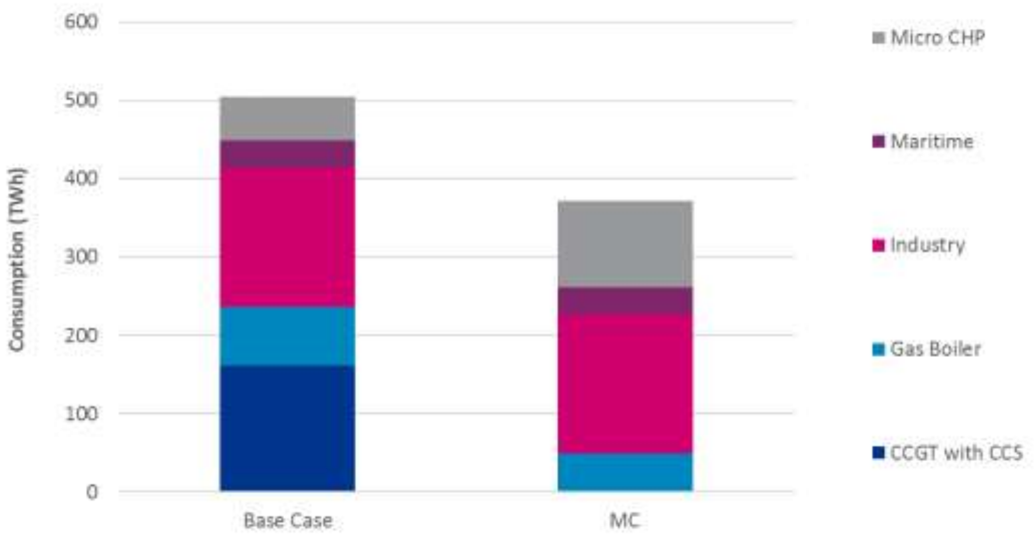


3.4.2.2 Gas/H_2

In the Monte Carlo model, the gas consumption has significantly decreased compared to the Base Scenario (which was already on a declining trend in 2050 compared to previous years), as shown in Figure 66. The shift away from gas is mainly due to CCGTs with CCS being less critical to the decarbonisation of the system thanks to a higher penetration of wind energy (further explained in the electricity section below).

The gas consumption of gas boilers and CCGTs is also partly picked up by Micro-CHPs, which increases the efficiency of the combined electricity and heat demand and further decreases gas consumption.

Figure 66 - Gas Consumption, Annual, 2050, Base vs MonteCarlo



3.4.2.3 Electricity

Three main features differentiate the capacity mixes (Figure 67) of the Monte Carlo and Base Scenario model:

- Higher penetration of wind capacity in the Monte Carlo model. This difference stems from the underlying load factors attributed to each model. The Base Scenario is based on peak conditions which assume a very low amount of wind during the whole week. The MC model on the other hand uses multiple Winter wind profiles and selects a case where the system is most stressed (due to more than just low wind). The Winter wind profile from the most stressful sim in the MonteCarlo model has an average load factor which is much higher than the deterministic Base Scenario peak week (30% vs 9%)[18]. This significant difference makes wind energy more valuable to the system, providing peak supply (and so displacing peaking capacity) as well as decarbonised annual energy. The direct effect of this increased renewable energy capacity is the displacement of CCS technologies which are no longer required to decarbonise the power sector.

[18] This suggests that the "1week in 10 years" approach for uncorrelated dimensions of temperature-and-wind, solar, and IC prices, is significantly more stressful than the "P95" winter week approach used in the monte-carlo analysis.

- Reduction in Solar capacity. Unlike for wind, the difference in solar output between the MonteCarlo Winter profiles and the deterministic Peak week is minimal, both showing very low solar output. Low carbon solar capacity is therefore displaced by low carbon wind capacity in the MonteCarlo simulation, which has a higher assumed load factor than in the deterministic scenarios.
- Additional storage capacity. In the MonteCarlo results, the bulk of the supply is now dominated by nuclear and wind (Figure 68). The lack of flexibility of this system configuration requires increased storage capacity to be added to complement the intermittent generation. Significant volumes of highly flexible Li-Ion batteries are added in the MC results (both home and grid scale), while longer duration Pumped Heat storage technologies actually decrease in capacity slightly.
- Use of Micro-CHP. An extra layer of flexibility and versatility is added through micro-CHPs. This distributed technology combined with home batteries gives the system flexibility to cope with greater intermittent wind penetration.
- Reduction in total supply volume. In the MonteCarlo run Micro-CHPs displace electric resistive heat, materially reducing electricity demand (and due to the high combined efficiency of Micro-CHP, reducing total energy demand of the whole system)

Figure 67 - Electricity Capacity, 2050, Base vs MonteCarlo

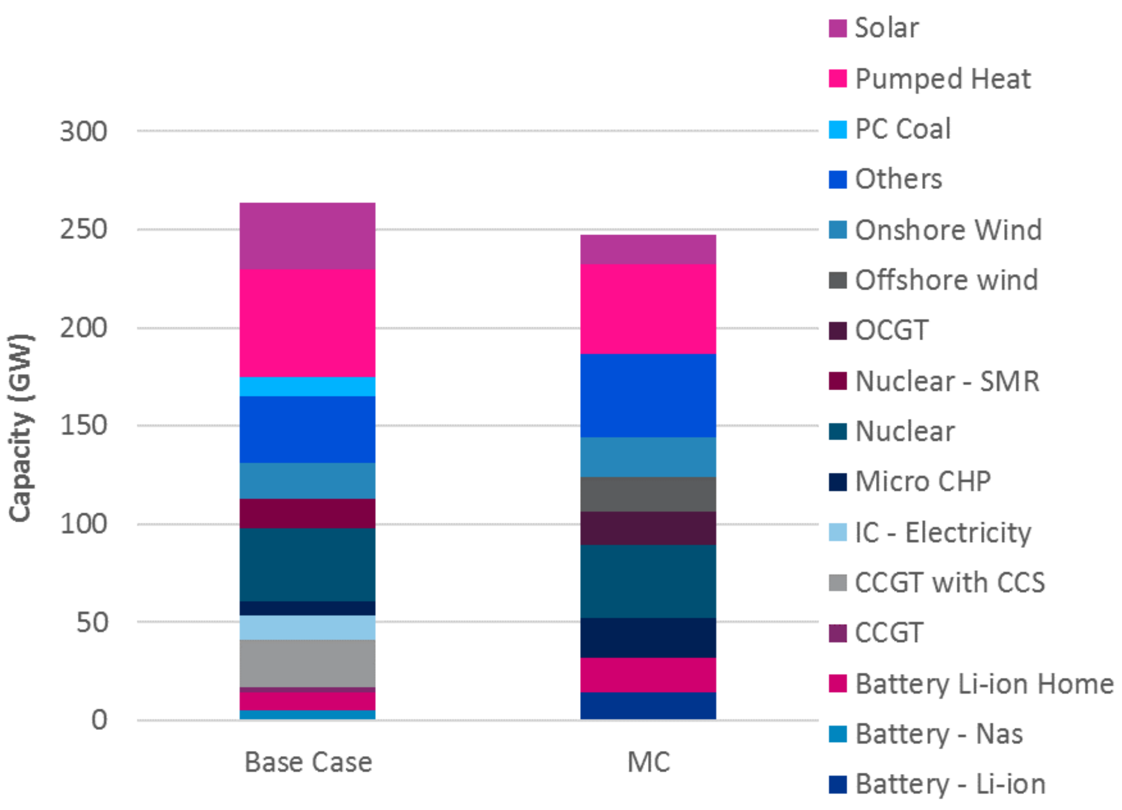


Figure 68 - Electricity supply, Annual, 2050, Base vs MonteCarlo

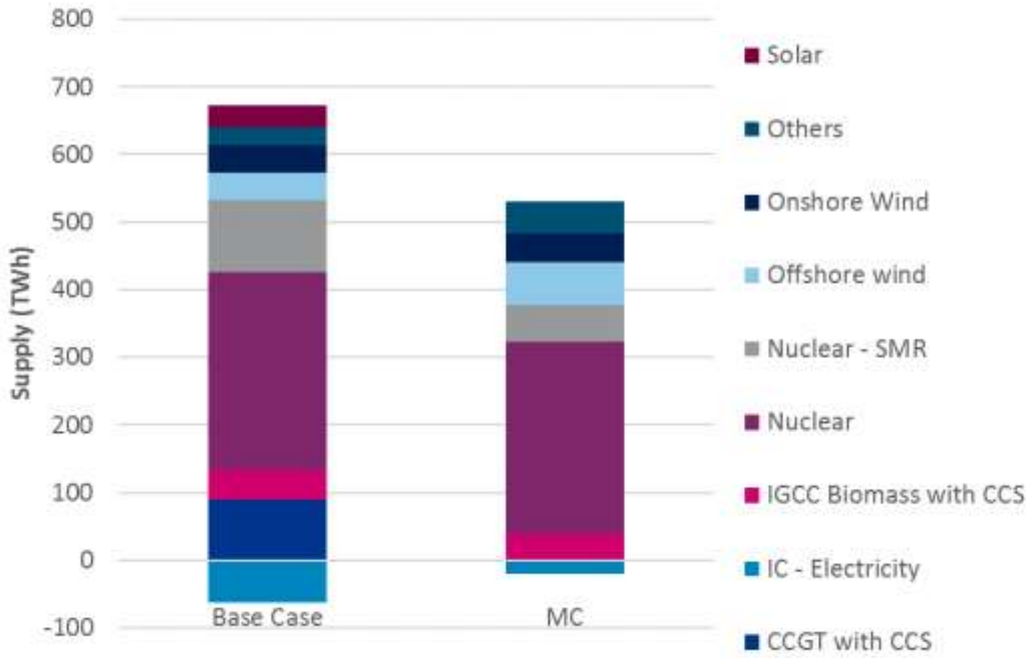


Figure 69 and Figure 70 show the evolution of electricity supply capacity in 2050 over successive model iterations, for the Base Scenario and Monte-Carlo runs respectively. It can be seen that due to the additional STM uncertainty in the Monte-Carlo case there is greater variation in the capacity of each iteration, and many more iterations are needed to reach a stable solution.

Figure 69 Electricity capacity evolution over coupling iterations, Base Scenario

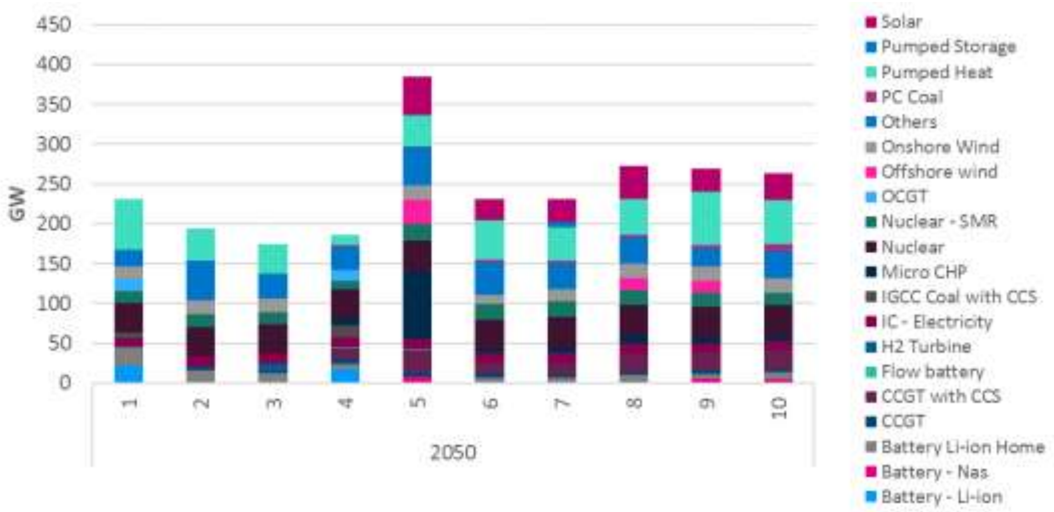


Figure 70 Electricity capacity evolution over coupling iterations, MonteCarlo

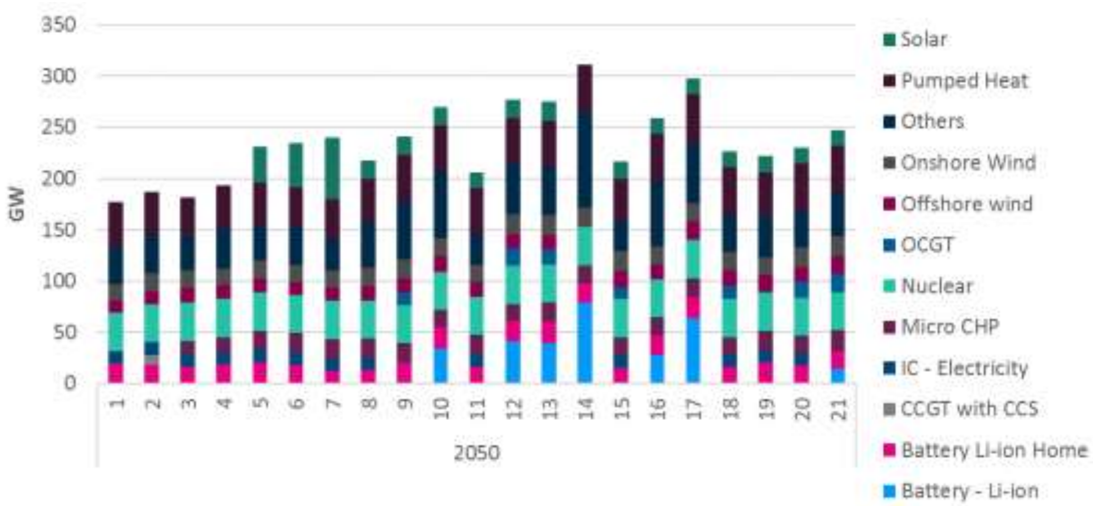


Figure 71 and Figure 72 show the system service requirements in 2050 in the Base and MonteCarlo runs respectively (for the MonteCarlo run the average of the 20 sims is shown). Frequency service requirements remain at a similar level in the MonteCarlo run, very slightly higher due to reduced electricity demand from electric heating and reduced inertia from CCGTs with CCS. Reserve requirements are markedly lower in the MonteCarlo run. Whilst wind capacity is higher in the MonteCarlo runs (increasing reserve requirements), this is offset by a large reduction solar capacity and electricity demand (decreasing reserve requirements).

Figure 71   System service requirement, 2050, Base

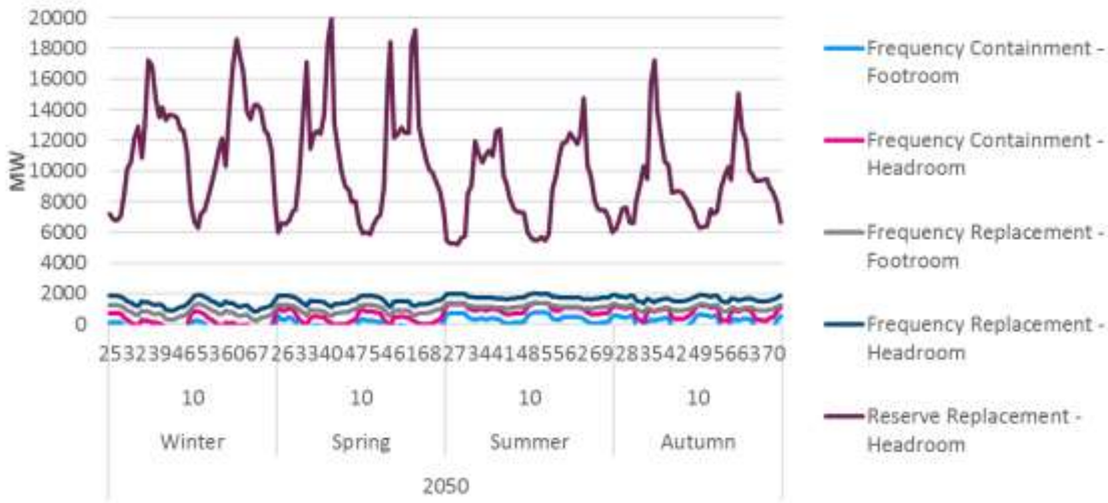
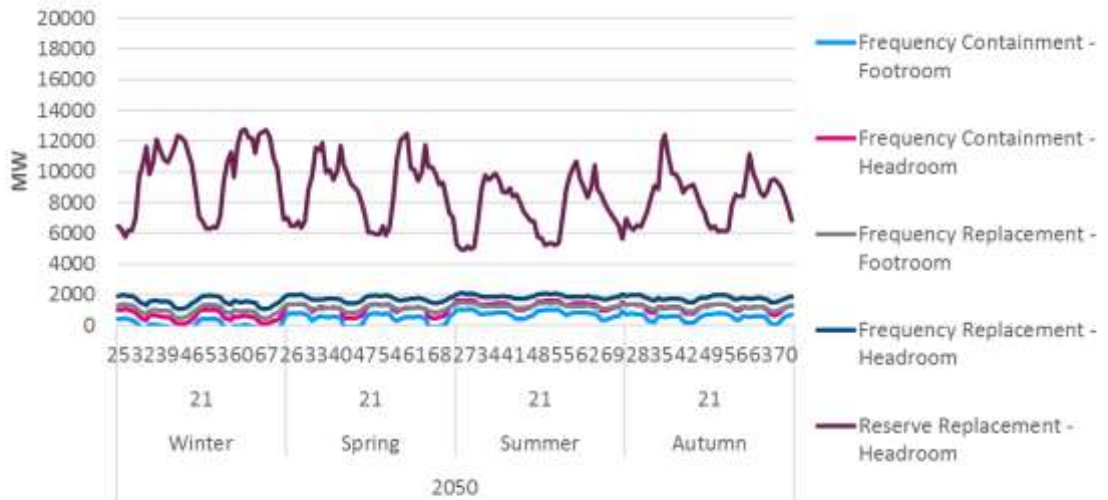


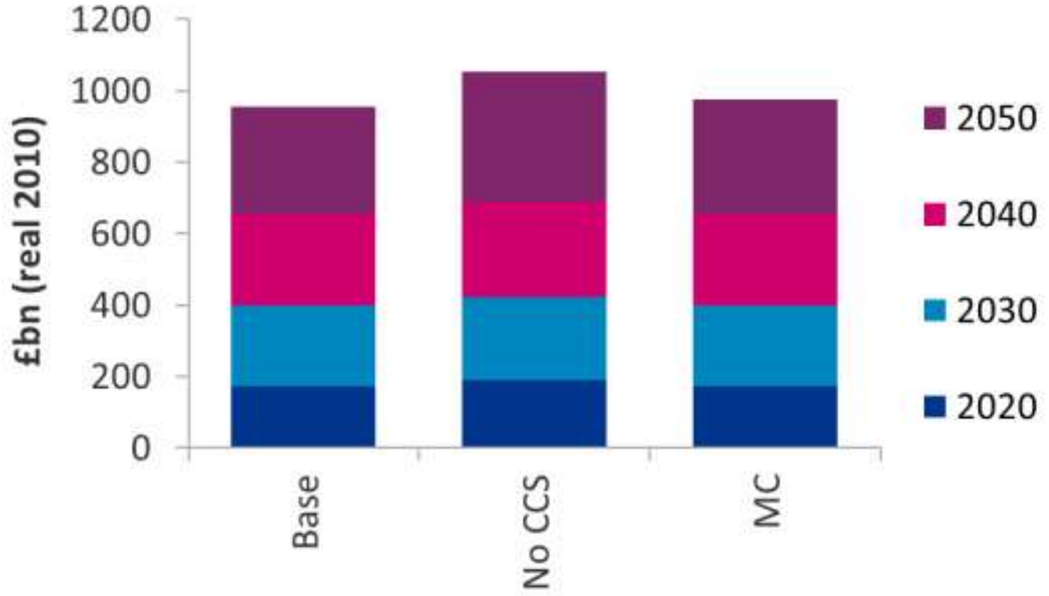
Figure 72   System service requirement, 2050, average over 20 sims, MonteCarlo



3.4.2.4 Total system cost

To understand the cost to the system of using the monte-carlo approach in the STM to define peak conditions rather than using the deterministic peak week, the total system costs can be considered. This includes the cost of all raw fuels, new investment, retrofit, and running costs, and is shown in Figure 73 for the Base, No CCS and MonteCarlo scenarios. It can be seen that while the No CCS scenario shows a significant increase in costs compared with the Base scenario, using the MonteCarlo representation of STM conditions results in very similar costs. Costs are identical 2020-2040, as the MonteCarlo scenario has focussed on uncertainty in 2050 only and uses the deterministic base scenario results prior to this point. In 2050, costs are nearly 7% higher in the MonteCarlo scenario, with an increase in technology investment costs but a reduction in resource costs. This is primarily driven by increased wind capacity and generation in the MonteCarlo scenario.

Figure 73 Total system costs, Base, No CCS and MonteCarlo



3.4.2.5 Conclusions

The main conclusions that can be inferred from this MonteCarlo analysis are:

- The peak conditions are similarly stressful in the MonteCarlo model as the Base Scenario, but the MC model assesses a greater range of possible stress events that may occur at different parts of the energy system. As a result, the capacity mix is designed to cope with a wider range of operating conditions.
- For heat, the total capacity requirements are higher in the MonteCarlo results, due to the uncertainty of weather related temperatures directly affecting heat demand.
  - There is a shift towards a more balanced supply mix, with MicroCHP and ground source heat pumps providing a more flexible and resilient system to whatever short term simulation is experienced, rather than a highly optimised system with niche technologies
- For electricity the total capacity requirements remain similar, though with a shift from Gas CCGT to Wind
  - Wind load factors are found to be on average much higher in stress periods than assumed in the Peak week of the Base scenario, resulting in their increased capacity and an elimination of CCGTs with CCS as a low carbon generation technology

  - Flexibility is required by the system due to the removal of CCGT with CCS and the increase in intermittent generation and is provided by significant volumes of short duration Li-Ion batteries.

- For gas, the annual consumption drops significantly due to the shift away from CCGTs with CCS as a way to decarbonise. The increased usage of micro-CHPs also makes the gas usage more efficient

4 Drivers of value for private investment

4.1 Overview

The results presented in the previous sections reflect a cost-optimised, 'central planning' view of how the system should evolve to deliver consumer end-use services at lowest cost, whilst reflecting carbon, security of supply and other constraints. The role of storage within this therefore reflects a set of options that help the central planner to reduce the overall costs of the system.

In practice, future storage investment is still likely to be a result of individual private investments subject to the prevailing set of market arrangements and Government policy. For example, the current Capacity Market (CM) provides a competitive mechanism for existing and new capacity (supply, storage and DSR) to help ensure adequate security of supply. Similarly, network use of system charges provides incentives (via avoidance of costs) which impact centralised versus decentralised and behind the meter generation, storage and DSR.

The intent of this section is to start to explore – via a small number of case studies - how the optimised results ascribe value to the main aspects of storage operation within the wider system; in terms of its ability to:

- Manage peak
- Provide broader system flexibility
- Provide more explicit system balancing services

The value of storage is explored via the use of illustrative Discounted Cashflow Analysis (DCF) for specific storage technologies. Results from the system model are used to create proxies of different revenue streams and these are contrasted against the investment and operating costs consistent with the inputs to the system modelling.

It should be noted that the purpose of this DCF is ***not*** to suggest whether a particular storage option is a suitable candidate for investment (e.g. if the DCF is negative) as in reality this is a function of unknown future market and policy arrangements. The fact that the optimised system solution has selected these technologies means they implicitly have value as part of delivering the lowest cost solution[19] for the UK as whole and therefore policy ideally needs to adapt to ensure these are delivered.

The intention is instead to help understand where the main share of value comes from, given the broad areas of market value that exist today and to what extent extra support might be needed if this is not sufficient. For example, the system optimised results assume a technology neutral investment hurdle rate of 8% in a world of perfect foresight whereas in reality private investors might require a higher number given the associated risks[20].

[19] For a given scenario and set of input assumptions.
[20] For example, the ability to lock in revenue via a long-term contract versus being exposed to a high degree of market uncertainty (e.g. a 15-year CM contract versus wholesale electricity price arbitrage).

4.2 Description of methodology

The DCF analysis is based on the choice for a specific storage technology assumed to start operation in a given year and location (by region and grid-level where relevant). All inputs and results are those associated with the Base Scenario.

The cost components of the DCF are relatively straightforward and uses the same input data that feeds into the SFM model

- Capital costs are based on the build year vintage and are assumed to be incurred during the first year of construction.
- Interest is incurred during the construction period at the hurdle rate and no revenues are allowed until construction is complete.
- Fixed annual operating maintenance costs are also added and are incurred over the technical life of the asset.

The revenue streams draw on shadow price outputs from a number of constraints within the SFM model. Linear interpolation is used for years in between the modelled time periods: 2020, 2030, 2040 and 2050. These technically reflect the change in the optimisation's objective function value from a one unit change in the constraint and hence are a 'proxy' for the marginal price used to achieve an equilibrium of supply and demand within a market. For example, what is the cost to provide one extra unit of energy supply (or avoided demand) at peak. The proxy revenue streams include:

- **Wholesale electricity price arbitrage**: this is based on the £/MWh shadow price for electricity in the STM (which reflects the marginal short-run cost of providing electricity) and the operating profile of storage, also in the STM. The difference in prices across injection and withdrawal periods coupled with the activity of the storage represents the achieved revenue.
- **Peaking capacity revenue**: this is based on the £/kW shadow price of the peak nodal reserve constraints in the LTM and represents the marginal value of supply or network capacity, (or avoided demand) to meet the highest peak demand period calculated in the SFM. Avoided network reinforcement costs at each grid level are captured by this revenue calculation, along with displacement of additional peaking supply technologies and DSR.
    - The potential revenue that a storage technology can capture is dependent on its PCF (Peak Capacity Function), which is based on its operation during peak conditions in the STM. This effectively creates a de-rating factor specific to each technology so that if the storage is not available or is being used for other purposes (e.g. system services) it cannot capture, or can only capture a portion of, this revenue stream.
    - This revenue stream is further divided by electricity product into **NTS** (i.e. transmission level peak capacity value) as well as at distribution level to reflect the value of managing peak supply further down the system. The distribution level electricity products are further divided based on the **urban/rural** archetypes and **HV/LV** representation in the SFM. If the storage technology is based at the LV-level

(e.g. a home battery) and is providing peak supply, it is assumed to be able to capture any value at LV-level along with the HV/NTS-levels above this.

- In addition, the shadow prices from the separate constraints ensuring sufficient reinforcement of the distribution network (split by HV/LV and urban/rural archetype)[21] are added to the capacity value from the peak nodal reserve constraints. In combination they represent the capacity value from providing peak supply and/or avoiding reinforcement across different parts of the distribution network.

- **System balancing services:** this is based on the £/kW shadow price for each system service from the LTM. This represents the marginal cost of building a technology to meet (or reduce the requirement for) the service. For each technology, the STM calculates an analogous de-rating factor, which represents to what extent the technology contributes to each of different system services across the year. Therefore, if the storage technology is not explicitly contributing to meeting the service in the STM it cannot capture any of the associated revenue in the DCF analysis. Separate shadow prices and revenue streams are calculated for:
  - Frequency containment headroom
  - Frequency containment footroom
  - Frequency replacement headroom
  - Frequency replacement footroom
  - Reserve replacement headroom

It should be noted that care needs to be taken when interpreting and using shadow prices[22], however, they are deemed to be sufficient proxies given the illustrative nature of this particular part of the analysis. It should also be noted that the shadow prices will not provide a value where the underlying constraint is not binding. For example, it may be that capacity is built earlier on in the pathway to resolve a particular constraint leading to a non-zero shadow price, however, in later years this capacity is sufficient to meet the underlying requirements and hence the shadow price for these later time periods will be zero.

4.2.1 Choice of storage technologies

The selection of three interesting storage technologies for the illustrative DCFs has been driven by a mix of factors, including:

- Technologies which form a significant part of the system solution along with those which appear to play a more marginal role
- A mix of dedicated-electricity and heat-based storage
- Large scale and small-building scale storage connected at different points on the network

[21] This is due to the way a number of separate constraints have been applied to bound the optimisation problem appropriately.
[22] For example, they imply a perfectly competitive market and only a represent a static snapshot of conditions (e.g. small variations in input assumptions may significantly alter the outturn shadow prices in a complex system).

- Storage providing system value across the range of peak, balancing services and broader system flexibility areas described above.

As a result, the following storage technologies have been chosen:

- **Building-scale space heat storage (5kW/10kWh)** starting operation in 2030 in On_East Midlands indirectly connected to an LV rural network. Heat storage plays a significant role across the pathway providing over 10 TWh of storage volume in total across all areas and several 100 GWs of implied output.
- **Building-scale Li-Ion battery (5kW/30kWh)** high-duration starting operation in 2050 in On_East Midlands connected to an LV urban network. This technology appears to play only a marginal role towards the end of the pathway with less than 2 GW deployed in 2050.
- **Pumped Heat Electricity Storage (100MW/500MWh)** low duration variant of this technology (5 hour vs 12 hours typical duration) starting operation in 2030 in On_London connected to the transmission system. This technology starts to play a sizeable role part way through the pathway with over 10 GW constructed by 2030, around 2/3 of this is focused on the lower duration variant and the remainder on medium duration variants (12-hours at full output).

4.3 Case 1: Building heat storage

The DCF in Figure 74 illustrates the significant value of building heat storage to managing peak electricity demand across the system by shifting electrified heat load, even subject to the overall requirements to meet building heat demands across the day.

The majority of the value is associated with reducing peak transmission system capacity followed by a smaller amount of value in avoided HV/LV distribution network capacity. However, this varies over the pathway and by 2050 there is more value in providing peak capacity at the HV network level. Wholesale electricity arbitrage revenues account for only 5% of value in the medium term but rise to 13% in 2040 and then sharply increase to around 70% of the total in 2050.

Compared to the low costs of heat storage, the implied revenues (assuming market arrangements exist to transfer this value to the consumer directly or indirectly[23]) are far greater, leading to a high positive return. This implies that heat storage is a highly cost-effective option and significantly below the marginal cost (or most expensive) option being used to manage peak electricity system requirements.

The core DCF analysis assumes the same 8% hurdle rate as the optimisation, however, in practice individual consumers are likely to have a far higher implicit discount rate. Figure 75 shows this under an assumed 20% hurdle rate but given the substantial value of the technology this makes limited difference to the implied return.

[23] I.e. as a direct payment or as an avoided cost.

Figure 74 Illustrative building heat storage DCF, operational 2030 (15 year life)

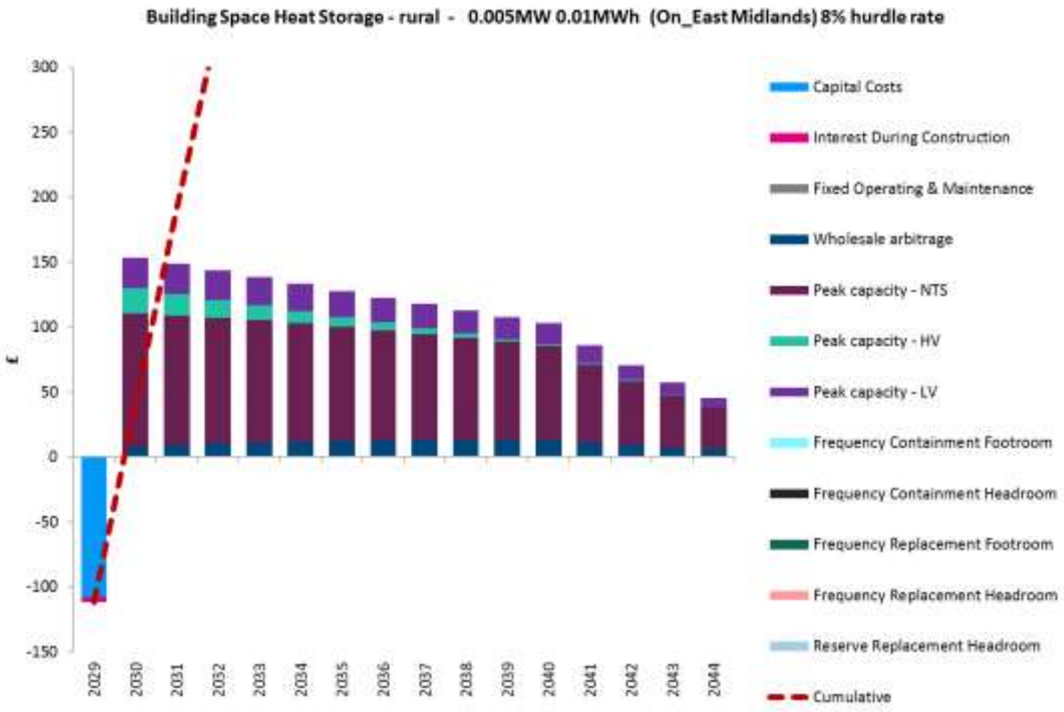
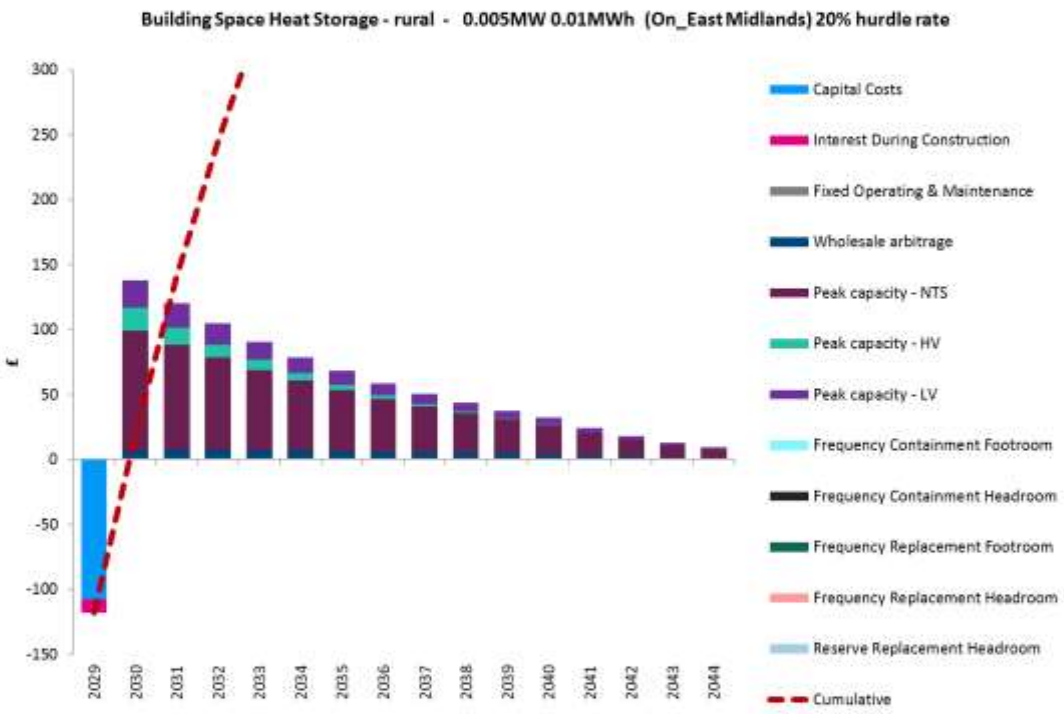


Figure 75 Illustrative building heat storage DCF with higher implied hurdle rate

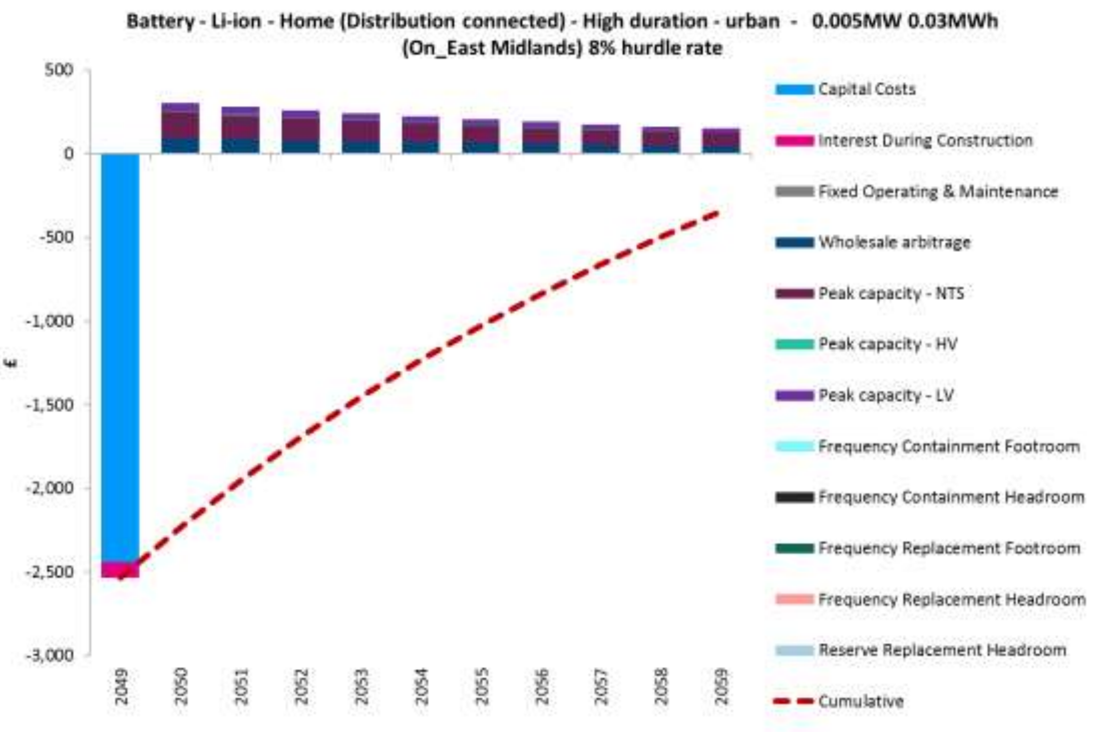


4.4 Case 2: Building Li-ion battery storage

Unlike building heat storage, the case for building-scale battery storage is far more balanced, even given the reductions in cost assumed by 2050. The core DCF in Figure 76 implies that the battery is close to making back its money with the 8% default return assumed in the SFM (at 5% it breaks even). The revenue streams presented here have been extracted as shadow prices from a MIP solution, and are therefore approximations of the true linear shadow price. We would expect all technologies built in the SFM to make back their money with the 8% hurdle rate assumed in the SFM. That this technology broadly breaks even, suggests that it is close to being the marginal plant in the model. By 2050, the share of value is split more evenly between wholesale electricity arbitrage and peak capacity value, with the latter focused around managing peak transmission capacity.

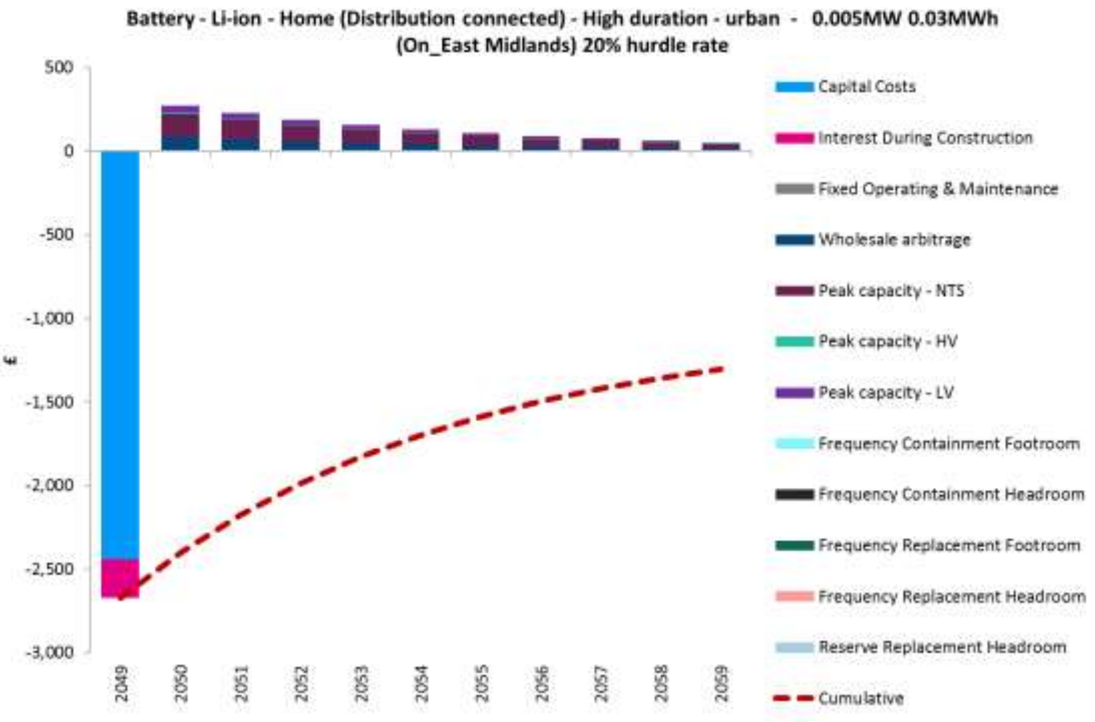
Furthermore, around 30% of the installed capacity of these batteries by 2050 is being used to provide frequency containment volumes. However, there is negligible value associated with the provision of these services by this point with the shadow prices and proxy revenue streams being zero. Given the high peak capacity values, this implies that the system is being designed primarily for this reason and a side-benefit is sufficient capacity within this stock to provide system services across the rest of the year without the need for additional dedicated system service technologies.

Figure 76 Illustrative building Li-ion battery storage DCF operational 2050 (10 year life)



As per the building heat storage case, a domestic consumer is likely to have a much higher implicit discount rate when installing a home battery. The DCF is repeated in Figure 77 with a 20% hurdle rate, leading to a considerable gap in revenue, equivalent to around half of the upfront costs of the battery, which would need to be filled by a different support mechanism.

Figure 77 Illustrative building Li-ion battery storage DCF with higher implied hurdle rate



4.5 Case 3: Pumped heat electricity

Case 3 provides an example of a large-scale transmission connected electricity storage technology deployed in 2030. Under the core assumption of an 8% hurdle rate the storage asset easily makes a sufficient return with the value being provided primarily through management of peak capacity at transmission level (it does not receive distribution level-revenue given its location on the system).

The storage is used in two main ways in the 2030s and 2040s. For the majority of the year the bulk of the capacity is used to provide balancing services, crudely split 2:1 between Frequency Containment and Reserve Replacement[24], leaving only a limited role to obtain revenues through wholesale electricity arbitrage. Separately, it is also used to provide peak capacity during the limited periods of extreme system stress. As noted in section 4.4, although this technology plays a key role in system services these are not valued explicitly as remuneration is provided primarily by peak capacity value, with these assets then free to provide system services at other times of the year and without the need for additional dedicated system service technologies.

Private investors are likely to require higher returns than the core 8% value given uncertainty around potential returns, for example, if the full value of the capacity revenues cannot be locked into a long-term contract in advance. Figure 79 shows the same DCF analysis at a hurdle rate of 14%, where the cumulative revenue is close to the break-even point.

[24] And not providing these services in the same timeslices where they are mutually exclusive.

Figure 78 Illustrative pumped heat electricity storage DCF, operational 2030 (20 year life)

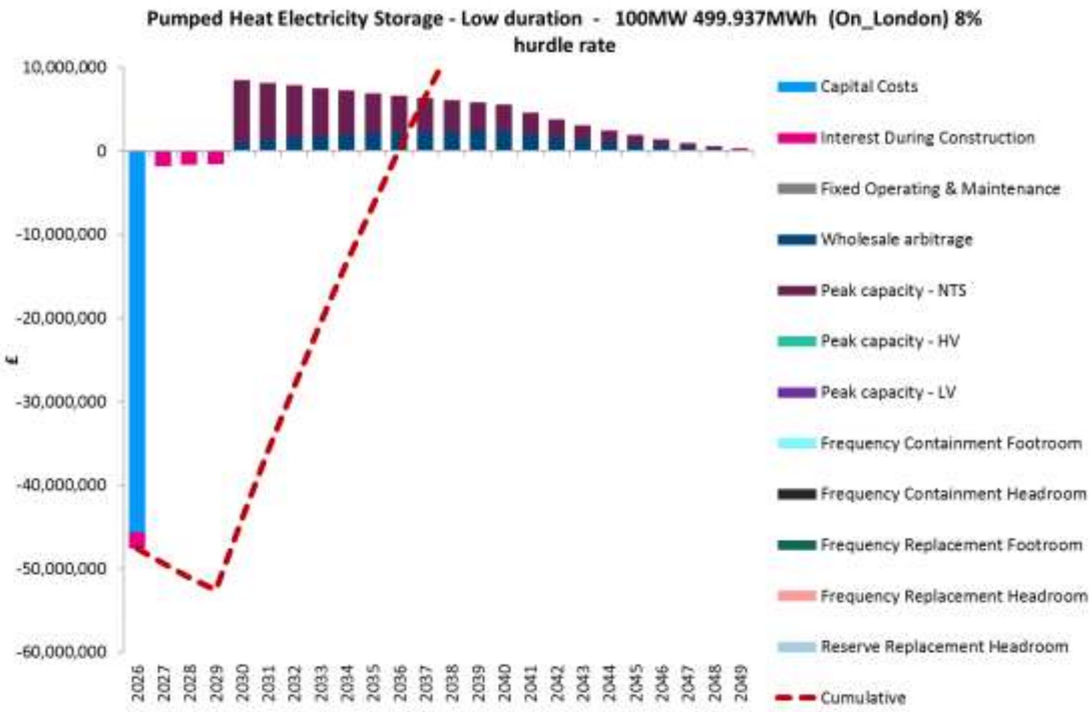
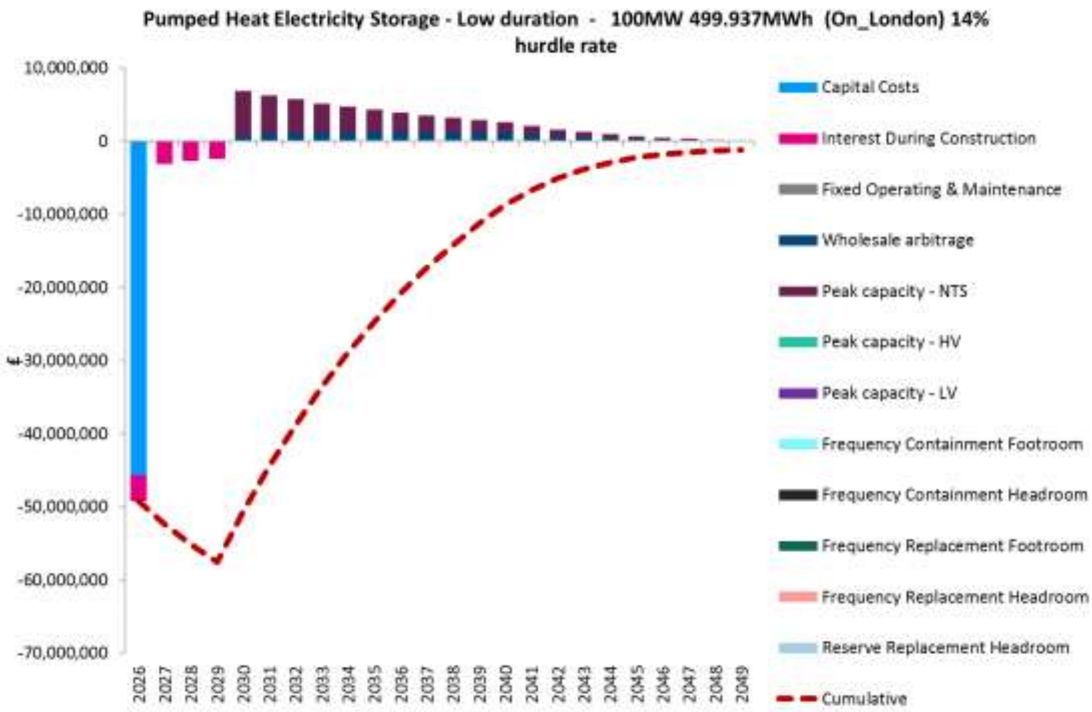


Figure 79 Illustrative pumped heat electricity storage DCF with higher hurdle rate



4.6 Monetising the future value of storage flexibility

As noted in section 1.1, Stage 1 of this project explored the near term potential for storage technologies and undertook a detailed review of the current market and regulatory arrangements within which they must operate (which is not repeated here). This report, through sections 3 and 4 above, has begun to explore the longer-term role for storage (and other forms of flexibility) within the overarching system and given an illustration of the key drivers of value for different forms of storage that may materialise.

In a number of cases, however, it is not clear that the current market arrangements are sufficient to allow private investors' business models to monetise the value from the different services and roles that storage can provide. At a high-level, many storage technologies are likely to need to stack a mix of revenue streams covering peak capacity provision, management of network constraints and wholesale arbitrage, particularly in later years given the increasing level of intermittent generation, and technical system services.

Whilst this diversity may increase the resilience of the asset to future market and regulatory changes accessing multiple revenue streams increases the complexity associated with constructing a viable business case and operating the asset. Accessing these multiple revenue streams can involve contracting directly with a number of different parties.

Going forward, new commercial arrangements[25] and business models may need emerge to allow storage assets to monetise the full range of benefits they provide to the energy system, a number of which are discussed briefly below.

Alleviation of network constraints

Current regulatory and commercial frameworks in GB do not allow for[26] either a) direct ownership of storage assets by the transmission or distribution network operator or b) direct compensation for new third-party owned storage assets for the avoided network reinforcement benefit they may provide to the system. The primary argument being that monopoly-related ownership or support may stifle innovation by other private developers.

Whilst some incentives exist for storage to help alleviate network constraints through the avoidance of Distribution (DUoS) and Transmission Network (TNUoS) use of system charges[27], these are somewhat blunt instruments designed to encourage load to be minimised at particular times of day.

[25] For example, these arrangements may include development of a framework agreement with the System Operator that allows an asset to contract for a number of Balancing Services simultaneously. The System Operator would then optimise which service is provided by which asset at any given time.
[26] Outside of Ofgem's network innovation projects.
[27] Which are currently being reviewed as part of Ofgem's Targeted Charging Review, given concerns such as the lack of cost-reflectivity with regards to avoided network capacity expansion https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-consultation

At present, more dynamic arrangements to provide flexibility in this area tend to ad-hoc (e.g. transmission constraint management contracts with the SO). Whilst there are arguments both for and against direct ownership of storage by network operators, an alternative would be an overarching market structure to help dynamically target flexibility from lower grid levels (e.g. a home battery) where it is needed across the system. This would ideally operate at something close to real-time, but cover transmission, distribution and behind-the-meter grid levels.

Integration of intermittent renewables

At present, the value of combining storage with intermittent renewables is either dampened or indirect. For example:

- The direct costs of curtailment (e.g. Balancing Mechanism constraint costs) are socialised across all market participant through the BSUoS[28] charge (which is the charge National Grid applies to recover the balancing costs they incur in managing the system in real time). Furthermore, the owner of the renewable asset will be indifferent in revenue terms between generating and being curtailed. Therefore, there is no way for the owner of a storage asset to monetise the benefit provided to the system of reducing renewable curtailment.
- Storage owners would have to contract bilaterally (or jointly develop) projects with owners of intermittent renewables to help smooth output and help to indirectly hedge against potentially large imbalance costs seen by these renewable operators through the Balancing Mechanism.

In a similar manner to alleviation of network constraints, the lack of a direct and overarching market mechanism that recognises the value of storage to the wider system may limit its deployment, compared to the cost-optimal modelling undertaken for this project.

Targeting flexibility appropriately across the system

Storage's impact on multiple businesses across the electricity value chain presents barriers to the efficient use and procurement of storage capacity and poses a question as to what commercial structure would facilitate its most efficient use. For example, in some scenarios a storage action may be simultaneously beneficial to one party and detrimental to another and could lead to an overall increase in the cost of operating the system. For example, a drop in transmission-level wind generation leads to a call on storage (or distributed generation more generally) to increase output. If the storage sites are clustered in a particular part of a DNO's network, they could cause a local peak in supply higher up the network and accelerating the requirement for reinforcement.

There will also be instances when a storage action has value to more than one entity at the same time. In such cases, the full value of storage cannot be realised through contracting with a single party, and a less than optimal volume of response will be forthcoming as a result. For example:

- Peak national demand may coincide with peak demand on a distribution network. In this period, increasing output from local storage may mean a transmission generator does not

[28] Balancing Use of System Charge

need to dispatch high variable cost peaking plant, and the DNO reduces peak demand, deferring the need for investment in network reinforcement.

- In an analogous manner, the results in section 4.5 for pumped heat electricity storage indicate that the dominant value is in the provision of peaking capacity, whilst the SO effectively gets the use of this capacity for 'free' to provide system services across the rest of the year. Unless separate value streams are ascribed to each or a condition of the peaking contract is to also provide the broader system services there is again no guarantee that the optimal volume of provision will be realised.

There is also scope for contractual inefficiencies. Typically, contracts for storage services will be struck bilaterally and endure for a period of time. This may prevent the resource being used by other parties and prevents sharing of costs. A particular example is the case of DNOs, who may need to dispatch storage services relatively infrequently (for example, in response to faults), which risks removing a valuable resource from the wider market which could be more valuable if employed elsewhere.

These issues of coordination have previously been identified and are the focus of thinking and analysis by many stakeholders in the sector including BEIS (and before it DECC), Ofgem, the Smart Grid Forum[29], the Energy Networks Association (ENA), ELEXON[30], and the DNOs as part of the Low Carbon Networks Fund innovation scheme. Ofgem has identified the need to establish an overarching market framework to enable DSR and is taking this forward through its Flexibility Project. In broad terms, proposals for its achievement can be distilled into three stages, each representing increasing degrees of intervention and market redesign to facilitate deployment and targeting of flexibility:

- *Stage 1* - initially, a shared services framework setting out how distribution level flexibility, such as storage, could be shared between DNOs and the SO. The ENA has proposed a concept to deliver this[31], envisaging a hierarchy of dispatch giving DNOs precedence in using flexible resources for local issues.
- *Stage 2* - an approach building on a similar principle but potentially allowing for greater coordination would involve one party (such as the SO) contracting for flexibility services and then selling them on to other parties (such as the DNOs) when they need them or place a higher value on them. Such a model would represent a more substantial change to the market framework, requiring for example reconsideration of price control frameworks.
- *Stage 3* - the ultimate level of coordination in use and procurement would be through establishment of a central market platform, allowing resource to be optimised across all sellers of flexibility services and buyers for all purposes. The market would need a locational element to its design to recognise the localised requirements of DNOs. Developing, operating and regulating such a platform would be a complex and costly task. This step would be justified only once flexibility requirements (e.g. to manage significant

[29] The customer-focused smart grid: Next steps for regulatory policy and commercial issues in GB Report of Workstream Six of the Smart Grid Forum, 2015
[30] Maximising the value from Demand Side Response
[31] ENA Demand Side Response Shared Services Working Group: Demand Side Response Shared Services Framework Concept Paper

EV/electrified heat load and embedded renewables) become significant, and the inefficiencies of preceding arrangements exceed the costs of a formalised, structured market.

Other flexible technologies

It is important to note that there are also a number of alternative technologies that can compete for the various value streams that would be available to storage assets, including traditional large thermal generators, smaller distributed thermal generators (including gas and diesel engines), various forms of DSR and interconnectors. These competitor technologies may have advantages over storage assets in terms of economics (i.e. capital costs), accepted business/operating models, proven development and deployment record and established routes for financing.

Whilst the current regulatory framework may favour traditional generation technologies over newer storage technologies these, largely fossil based, plant are likely to be squeezed due to the requirement to decarbonise the electricity system. However, it is likely that the broader policy framework will evolve to recognise these other forms of low carbon flexibility, which may enhance competition with storage.

For example, a H_2 turbine could provide a valuable low carbon mid-merit replacement for a CCGT. At present neither the Capacity Market (providing value for peak capacity agnostic of carbon intensity) nor the Contract for Difference mechanism (primarily supporting baseload or intermittent low carbon plant) appropriately reflect the value – and hence remunerate appropriately – the potential role that such a technology could play.

5 Conclusions

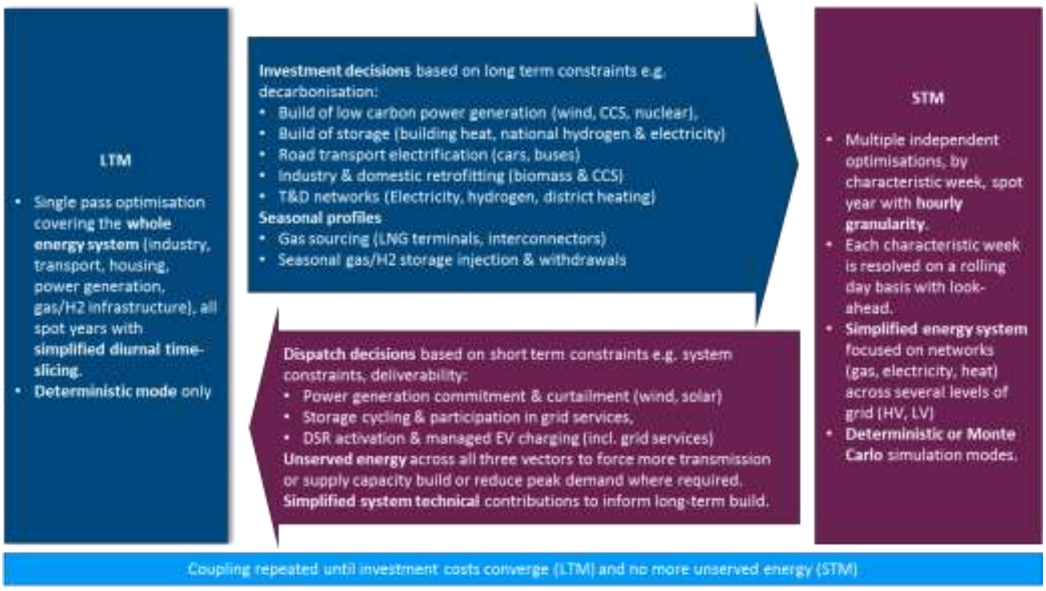
5.1 Overview of modelling framework

The complexity of the issue to be modelled means that it is intractable to represent this in a single optimisation problem. Instead, the SFM consists of two hard-linked optimisation modules:

- Long Term Module (LTM), which is an enhanced version of the ETI's Energy System Modelling Environment (ESME) v4.1 model covering both long-term capacity expansion and simplified operation of the system. Key enhancements for this project have included:
  - Explicit representation of the gas network and storage technologies, along with multi-vector conversion routes such as Power to Synthetic Natural Gas
  - A broader range of storage technologies across heat and electricity
  - Updated representation of peak capacity requirements and system services for frequency (containment / replacement) and reserve
  - More granular, archetypal representation of electricity distribution networks and the technologies connected to these; differentiating rural/urban and high/low voltage
- Short Term Module (STM), a bespoke extension for this project, focused on the detailed operation of the system only (i.e. without consideration of capacity expansion.
  - This provides detailed hourly operation of the integrated energy system for electricity (reflecting e.g. unit commitment and other dynamic constraints on operation such as ramp rates), gas, hydrogen and heat across a number of characteristic weeks including proxies of operation for sub-hourly system service requirements.
  - In addition to a detailed view of supply-side flexibility, the STM provides a detailed representation of demand-side flexibility across electric vehicles, heat storage, industrial demand side response and use of electrolysers.

The SFM iterates between these modules passing information from one to the other (i.e. at a high level the LTM frames the long-term system and the STM helps it to understand what the detailed operation of the system would look like) until a stable equilibrium is reached based on user-defined stopping criteria. These broadly represent a limited change in the LTM system design between iterations and negligible unserved energy when operating this system in the STM. The STM can be run in either a deterministic mode (with a dedicated peak week alongside four characteristic seasonal weeks) or a Monte Carlo mode whereby key operational drivers such as wind, solar and temperature profiles, interconnector prices and unplanned outages are simulated (across the four characteristic seasonal weeks).

Figure 80 Overview of Storage and Flexibility Model



5.2 Scenario analysis

As part of helping to demonstrate a working release 1.1 of the SFM and to illustrate the types of insights that this modelling framework can provide going forwards, two deterministic scenarios have been explored:

- The **Base Scenario** represents a central view of all key parameters and takes many of its assumptions from the ESME v4.1 Reference model upon which the LTM was based. Further data has been added for the LTM additions mentioned above, as well as supplementary information needed for the STM (e.g. shaping profiles to convert aggregate heat service demands or wind/solar outputs to an hourly granularity)
- The **No CCS Scenario** represents a form of "stress test", as previous experience (e.g. using ESME) shows that without this technology the energy system is materially harder to decarbonise. This, for example, leads to greater deployment of intermittent renewables and correspondingly greater system flexibility and Reserve requirements.

Additionally, short term uncertainty has been analysed in terms of its impact on capacity build in 2050:

- The **Monte-Carlo** run uses long term assumptions consistent with the Base scenario, but with short term uncertainties represented by 20 independent simulations of the STM. These uncertainties include: wind and solar output, plant outages, electricity interconnector import prices, temperature. The Monte-Carlo capacity decisions up to 2040 are fixed to match the Base scenario solution, but decisions in the final time period, 2050, are optimised based on the information from the Monte-Carlo STM simulation.

Considering the research questions that this project has designed a tool to answer, the following insights have been found (subject to the caveats outlined in 3.1.1)

- **What is the future role of energy storage in the energy system considering flexibility within and across multiple vectors, points in the system and services?**
  - The requirement for storage capacity is likely to increase substantially by 2050 (270GW of heat storage and 80GW of electricity storage in the Base scenario)
    - In the heat sector, building level heat storage can provide an immediate benefit to the system, primarily due to providing peak load capacity
    - In the electricity sector there is less need for storage until 2050, where the need increases considerably due to decarbonisation targets reducing flexible generation and increasing peak supply
    - In the gas sector there is likely to be sufficient capacity in existing storage, with no new build storage required as gas demand gradually decreases
  - The primary use for storage in 2050 is peak load reduction, rather than provision of system services (though storage does provide the bulk of these services)
  - Heat storage is critical to decarbonising the heat sector through electrification, while decoupling the electricity system from the large swings in demand from the heat sector
  - The key storage technology in the electricity sector is likely to be grid scale Pumped Heat, however, home level battery storage is also valued due to its ability to reduce peak demand at all grid levels
  - The need for storage is related to the availability of other forms of flexibility
    - When flexible CCGT with CCS technologies are removed in the No CCS scenario the need for storage increases in all sectors
    - Where electric vehicles operate under managed charging this can be used to balance electrified heat, thus reducing the requirement for flexible dedicated storage technologies
- **What is the scale of the different future service requirements (e.g. in MW, MWh) and how do interactions across multiple parts of the energy system influence these?**
  - Reserve requirements are likely to increase substantially (to 30GW in the No CCS scenario), due to increases in electricity demand (from electrification of heat and transport), and wind and solar generation (decarbonisation of electricity sector)
  - Frequency service requirements are likely to decrease, as high inertia nuclear generation dominates decarbonised electricity supply
- **What is the value of various forms of storage to the system, both in the most immediate part of the system and indirectly to wider parts of the system, e.g. through multi-vector interactions?**
  - The most valuable service that storage can provide is in providing peak load capacity, and displacing other supply or network reinforcement
  - Both Reserve and Frequency services can be provided by flexible capacity built primarily to meet peak load, with little value in providing these services

- Building level heat storage is one of the most valuable storage technologies, providing behind the meter peak load reduction that has an impact on load at all grid levels and across multiple energy vectors

- **How do the key drivers of uncertainty (both short- and long-term) affect the potential role of storage and the competing alternatives?**
  - Materially higher volumes of storage will be required if CCS technologies fail to materialise, 28GW additional heat storage and 75GW additional electricity storage, plus additional flexibility from EVs with managed charging
  - Where flexible CCGT with CCS technologies are not available the system has a greater need for highly flexible short duration storage technologies (Li-Ion batteries) rather than longer duration storage technologies (Pumped Heat)
  - Where short term uncertainty is included through Monte-Carlo simulation, the SFM designs a system that is more resilient to a range of operating conditions
    - A more diversified capacity mix, increased in total capacity
    - Increased capacity and utilisation of hybrid technologies (e.g. Micro-CHP) which prove suitable for a range of conditions
  - The Monte-Carlo runs show the risk of using a single set of operating conditions when designing a system, in this case the Base scenario undervalues the role of wind generation
    - In the Monte-Carlo runs wind capacity is increased, reducing CCGT with CCS capacity and increasing flexible electrical storage capacity

5.3 Drivers of value for private investment

In addition to the overall system analysis three illustrative storage case studies have been explored from a private investor perspective – using a proxy Discounted Cashflow (DCF) analysis based on the Base Scenario results – to help understand:

- Where and to what extent the value for these technologies materialises across the system (e.g. managing peak, providing broader system flexibility or more explicit provision of technical system services)
- To what extent increased private investment risks (necessitating a higher hurdle rate) can be accommodated given the implied system value from the Base Scenario results.

The case studies covered building-scale heat storage, a home building-scale Li-ion battery and a large-scale pumped heat electricity storage site. In all cases, the most material value drivers stemmed from provision of peak capacity and to a lesser extent avoided distribution network reinforcement across the pathway. Energy arbitrage revenues played only a modest role in the medium term, but grew significantly by 2050 given, for example, the expansion of intermittent generation on the system. Building heat storage and pumped heat electricity storage still showed positive returns with hurdle rates above the default 8% assumed in the LTM, whereas this was not the case for the Home Li-Ion battery, which implies that this is (or is close to being) the marginal cost technology from the overall system's perspective.

5.4 Limitations of the model and areas for further work

The project has both scoped and developed a working "Release 1.1" SFM model and demonstrated the value of including a temporally detailed multi-vector analysis of system operation alongside the traditional whole system view of long-term capacity expansion (with a more limited operational view).

While the model can give new insights not previously available from existing models, it has a number of limitations that reduce its potential uses.

These limitations are documented in detail in Appendix A. A summary of their impact, effort to improve, and effect on performance is given in Table 4 below.

Table 4 Limitations of R1.1 SFM

Limitation	Impact on results	Effort to improve	Effect on performance
Lack of LDN voltage constraints	Low	Medium	Moderate
Lack of Voltage Regulation constraints	Medium	High	Moderate
Simplified LDN granularity	Medium	Medium	Poor
Storage service provision as function of state	Medium	Medium	Poor
LTM / STM coupling	High	High	Moderate
Search space – no guarantee of global minimum	High	High	Poor
Electrolyser and hydrogen storage refinement	Medium	Medium	Moderate
Performance	High	Medium/High	Good

Appendix A Potential enhancements to R1.1 SFM model

A.1 LDN voltage constraints

One potential use of storage technologies in the electricity sector is to relieve voltage constraints seen in LDNs. This section discusses how this could be implemented in a future version of the SFM.

A.1.1 Rationale

Voltages within LDNs must be managed to be within certain limits, to ensure safe delivery of power and to protect connected equipment. The voltage decreases as power is transmitted along the network, due to resistive losses. Long lines in rural networks in particular can experience significant voltage drops.

Increased load on the network increases power flow and therefore voltage drops, and so some LDNs can be constrained in the ability to take any more load, due to associated voltage drops taking voltage outside of statutory limits. Similarly, large sources of distributed generation can result in the voltage rising locally, outside of statutory limits.

Keeping LDN voltages within these limits results in potential constraints on the nature of evolution of supply and demand within the LDN. These voltage constraints are highly dependent on the topology and make-up of the particular LDN and are not easily parameterised (e.g. into archetypal LDNs with cost curves, as per LDN thermal constraints in the SFM R1.1).

From discussions with DNOs, voltage constraints generally occur less often than thermal constraints and can be relieved at lower cost, as a result voltage constraints have not been included in R1.1 of the model. However, relieving LDN voltage constraints is one possible (albeit relatively small) extra benefit that electricity storage can bring to the system.

A.1.2 How it could be included in a future version of SFM

It is assumed that under any future operating model of LDNs ("Distribution System Operator" model or otherwise) the voltage within the network will need to be managed to within current limits. From discussions with DNOs future voltage constraints are likely to occur as a result of potential new large sites of demand or supply within the LDN. These can be managed quite easily through an obligation on new sites to self-manage their voltage (though capacitors, inductors or other dedicated technologies). Storage technologies could also manage LDN voltages, at a higher cost for installation but with other potential system benefits.

One potential methodology for including the effect of voltage constraints (and the ability of storage technologies to relieve them) is to add a constraint to the SFM that forces all new large generation technologies built at distribution level to be co-located with a voltage control technology such as a capacitor or storage. The SFM would not attempt to model the complex power flows that allow voltage constraints to be analysed in reality, but rather would assume there is some average self-balancing requirement for all new large generation sites and allow the model to choose cheaper "voltage only" technologies or more expensive storage technologies (with other system benefits).

A.2 Voltage regulation

"Voltage regulation" in this context refers to the management of voltages at the transmission level of the electricity network, through the injection or absorption of reactive power. This is essentially a reactive power balancing problem, where reactive power demand must be met (within some tolerance) by reactive power supply. Reactive power cannot be transmitted over long distances, and so any balancing must be done at a local level. This is in contrast to the control of frequency which depends on the overall system active power balance.

This section discusses how this functionality could be implemented in a future version of the SFM.

A.2.1 Rationale

Voltage at the transmission level is kept within tight operational limits to ensure safe delivery of power and to protect connected equipment. The actual voltage level can vary with the size and nature of the supply and demand that is instantaneously active, and so requires balancing via the injection or absorption of reactive power. Power electronic connected devices (e.g. batteries, solar generation) also have the capability to provide reactive power if sized correctly; and voltage control services may be one use for such devices in the future.

While the requirement for voltage control varies continuously, historically there has been a baseload need for the injection of reactive power, to balance inductive loads (e.g. in motors and heavily loaded transmission cables). In recent years there has been a marked decrease in this inductive load, and an increase in capacitive load (e.g. LED lighting, lightly loaded transmission cables), which has changed the requirement for baseload injection of reactive power to baseload consumption of reactive power. This trend is set to continue, with National Grid projecting a large increase in the requirement for reactive power absorption[32].

This requirement can be met by spinning generation plant (currently through Obligatory Reactive Power Service), dedicated reactive power compensation technologies (capacitors, inductors, STATCOMs, etc), and power electronic connected devices (solar generation, batteries, etc). Typically, the cost of dedicated reactive power technologies is lower than power electronic technologies if just used for reactive power compensation, but power electronic technologies (like storage) have other system benefits.

By excluding voltage regulation from the SFM R1.1, there is the potential for ignoring some potential small additional value of storage to the system.

[32] System Operability Framework 2016, National Grid https://www.nationalgrid.com/sites/default/files/documents/8589937803-SOF%202016%20-%20Full%20Interactive%20Document.pdf

A.2.2 How it could be included in a future version of SFM

As part of the development of the SFM R1.1, a framework for including voltage regulation constraints has been developed. This relies on satisfactory data to parameterise the problem. As part of this project Baringa have had a number of discussions with the System Operator and DNOs but have been unable to find data of sufficient quality to include a good representation of Voltage Regulation within the SFM R1.1. In the following text this framework is outlined, along with what data is needed to allow it to be implemented in a future version of the SFM.

The high-level framework is to consider reactive power as analogous to real power and apply a set of reactive power balancing constraints to the model in a similar manner to the real power balancing constraints that are central to the SFM. This requires having a representation of all reactive power demands and supply sources.

Reactive power must be balanced at a local level, to ensure voltages are kept within limits in every locality on the network. Whereas real power can be transmitted fairly long distances (with associated losses) reactive power cannot and must be balanced locally to avoid large voltage deviations. This could be implemented in the SFM through a series of independent reactive power balance constraints, one for each node of the model. This assumes that no reactive power is transmitted between nodes.

Within each node, the demand and supply of reactive power must be calculated. For real power, the SFM has a detailed representation the diurnal shape of demand from different technologies and then ensures hourly balancing of this demand through the dispatch generation and storage technologies. In principle, this approach could be applied for reactive power too, though the nature of reactive load for particular demand technologies is not well understood and is likely to change significantly over time. For this reason, it is very challenging to calculate the reactive power demands endogenously, as for real power demands.

An alternative approach is to apply an exogenous "reactive power requirement" that must be balanced by supply type technologies (though these could be inductive, i.e. negative reactive power supply). This is closer in approach to the system services, where there is a "requirement" that must be met by various technologies, each with different supply characteristics. Forecasts for reactive power are used that come from National Grid in their System Operability Framework (2015 and 2016) documents to calculate what this reactive power requirement may be, though the granularity of data available is not high and many assumptions have had to be made to give a diurnal shape and geographical split to the requirement.

On the supply side, the parameters of reactive power compensation are better understood and could in principle be calculated endogenously based on the capacity and operation of different type of reactive power compensation technologies. The reactive power constraint would ensure that there was equal reactive power compensation to match the exogenous reactive power requirement.

The list of technologies considered is in Table 5, along with their range of reactive power output, Q. Spinning plant provide reactive power limited by their real power output. Power electronic devices are assumed to have inverters sized to allow equal instantaneous real power P and reactive power Q, making these independent from one another. Shunt capacitors and reactors provide fixed baseload reactive power compensation, but STATCOMS provide flexible compensation.

Table 5 Reactive power compensation technologies

	Type	Min Q (VAr)	Max Q (VAr)
Spinning plant	Scalar on real power output P	-0.0975*P	0.2775*P
Power electronic connected generation / storage	Independent of P	- Max Capacity	Max Capacity
Shunt capacitor / reactors	Static value	Fixed value (may be +'ve or –'ve)	
STATCOMs	Independent of P	- Max Capacity	Max Capacity

The final data required to calculate the cost of providing reactive power compensation is the existing capacity of reactive power compensation technologies. The equipment lists from National Grid's Electricity Ten Year Statement 2016[33] have been used. Again, assumptions have had to be taken to disaggregate this data for the geographical regions of the SFM.

When the capacity of existing technologies is compared to the requirements calculated above, it is found that the current requirements cannot be met. This suggests that the data and assumptions take have not resulted in good data for inclusion in the SFM. For this reason, voltage regulation has not been included at in R1.1 of the SFM. However, if better data was to become available it could be included in a future release.

A.3 LDN Granularity

A.3.1 Rationale

Currently, only four different combinations of LDN archetypes are considered (LV/HV and urban/rural). This design choice was made to balance representativeness (given available data) with acceptable performance. In principle, the underlying data source (ETI's Macro Electricity Distribution Tool) provides a more detailed level of disaggregation (EHV/HV/LV and 8 archetypal spatial networks such as semi-urban or semi-rural). Increasing the LDN granularity would provide more insights on where storage/distributed generation should be built, and which part of the network would be reinforced in priority as a result.

A.3.2 How it could be included in a future version of SFM

The inclusion of these archetypes does not pose any major implementation or modelling issues since the framework is similar to the existing one. The challenge is rather gathering the data to populate the different versions of a same technology (e.g. a Li-ion battery could be installed at each grid level

[33] https://www.nationalgrid.com/uk/publications/electricity-ten-year-statement-etys

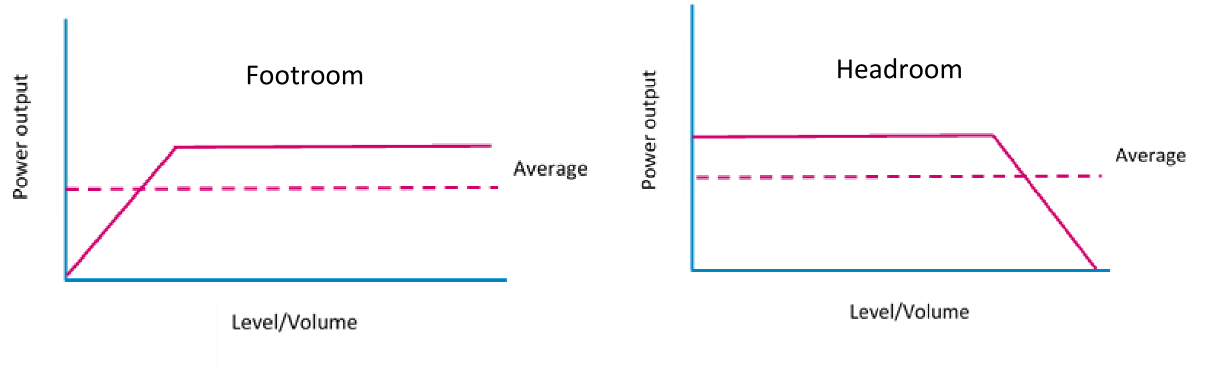
and on each spatial archetype[34]) and the longer computation time resulting from the multiplication of decision variables associated with these additional technologies.

A.4 Storage service provision as function of state

A.4.1 Rationale

The contribution to energy services of a storage technology should depend on the storage level (Figure 81) e.g. if the service has a long duration (reserve replacement for instance) and the storage has a low energy volume/level, then the storage will not be able to provide its maximum output rate for the full duration. Currently, the contribution is taken as the average:

Figure 81 Examples of energy service contribution curves for storage technologies



Having the contribution function following the "kinked" curve rather than the average will have an impact on the storage operation. It will create a nominal operational zone where footroom and headroom contribution are maximised and therefore will push the storage technology to operate in this range. However, operating in this narrowed range will reduce the flexibility of the technology for arbitrage, peak shaving purposes. A trade-off will occur which is currently not represented.

A.4.2 How it could be included in a future version of SFM

The main drawback of this representation is its non-linearity which incur significant computation time issues. The current representation can be improved by either defining a more accurate linear formulation or by implementing the non-linear constraint and trimming down complexity on other aspects.

[34] In many cases it may acceptable to duplicate the per unit technology costs directly, whereas others (e.g. the split of buildings by type on each network archetype) would require further data gathering.

A.5 Improved LTM/STM coupling

A.5.1 Rationale

The coupling between LTM and STM is already hard-linked with iterations across the modules, with a solution which stabilises gradually. However, it is likely to be possible to improve the coupling behaviour further to accelerate the convergence process. Refinements to the coupling logic can guide the coupled model to a suitable area of the solution space more quickly by discounting poor aspects of prior solutions. Changes to coupling logic for example, a non-exhaustive list of possible enhancements includes:

- Apply availability factors in the LTM as functions based on installed capacity rather than using static STM values. The advantage of this representation would be to introduce a diminishing marginal return dimension in the LTM as more capacity is installed (i.e. analogous to the PCF functions for peak capacity.
- Recognising systematic sources of unserved energy. Some nodes/energy vectors are inherently more difficult to balance (e.g. London does not have the possibility to build power stations while having a high demand). Recognising these patterns would accelerate the convergence by adding heuristics to skip or adjust the information passed back to the LTM in the first few coupling iterations.

A.5.2 How it could be included in a future version of SFM

The implementation of availability factors functions would largely rely on the structure of Peak Contribution Factors i.e. compile STM results from previous iterations, interpolate regression functions, implement different tranches with diminishing availability factors based on installed capacity.

The second feature would require some hindsight accrued after a longer period of usage in order to highlight shortcuts that the iterative process could/should take to accelerate convergence. The implementation could, for example, use a pre-emptive mark-up in the unserved energy indicator at the relevant energy vectors/nodes in order to accelerate the initial searching steps.

A.6 Ensuring sufficient coverage of solution search space

A.6.1 Rationale

The original rationale for separating the SFM into two coupled, but separate, optimisation modules was to avoid an intractably complicated single optimisation problem. This rationale still holds given the complexity observed in each of the individual modules. However, as a consequence, it is not possible to prove that a stable SFM solution (across both modules) is equivalent to the global optimum that would be seen by the single optimisation problem, for the same set of starting exogenous inputs.

As the SFM model progresses, different aspects of the solution space are explored, but the pathway of exploration is dependent on the starting data or 'seed' used in the first LTM iteration. As a result, it is possible that the first STM solution (given the starting conditions and subsequent solution from the first LTM iteration) and all subsequent coupling iterations only explore a subset of the overarching solution space. For example, the degree of electrification of heat supply is never above 30%. This could result in funnelling of the final solution towards what would be considered a local optimum solution, as opposed to the global optimum that would be determined by the unknowable single optimisation problem (e.g. if optimal heat electrification if significantly greater than 30% this part of the solution space would not have been explored).

A.6.2 How it could be included in a future version of SFM

Given that it is intractable to create a single optimisation problem, the best that can be achieved is to force the SFM to cover a broader part of the solution space to minimise the risk that the final solution is a trapped in a local optimum. It is, however, not possible to prove that this has occurred and would potentially entail significantly longer SFM run times given a broader search of the solution space.

There are a number of possible options for implementing this in practice, including:

- Forcing the SFM to explore a broader range of system conditions in early iterations before allowing it to converge with information gleaned from this broader set. For example, if the maximum degree of electrification of heat and transport is not explored by the model when using the current standard SFM process, this could be forced further via explicit constraints.
- The core SFM process could be run a number of times fixing key aspects of the solution (e.g. the degree of electrification) but letting other parts of the system vary through the usual convergence process and at the end inspecting the solution across the multiples sets of results.

In all approaches, the crucial factor is the user's knowledge of the underlying energy system problem, its data and the key conditions that drive different parts of the solution space, such that these conditions can be tested explicitly within the SFM, so refining the core convergence process.

A.7 Electrolyser and hydrogen storage refinement

A.7.1 Rationale

Electrolysers and hydrogen storage are included in the STM with some flexibility over how they run – they can run at any point in the day as long as the daily hydrogen demand volume (from the LTM) is met. This allows any spare electrolyser and storage capacity to be used for system services and general energy balancing. However, the approach gives no reason for hydrogen storage to be used for anything more than within day balancing. In reality hydrogen could be stored in long duration facilities (salt caverns for example) to allow seasonal energy arbitrage, potentially using excess wind in summer to produce hydrogen with electrolysers which is then used for heating in winter.

The LTM has an optimising horizon that can see the potential benefits of longer duration storage (weeks, months), but this information is not passed to the STM, and so longer duration hydrogen storage is unlikely to be well utilised in the STM.

A.7.2 How it could be included in a future version of SFM

To allow electrolysers and hydrogen storage to be used in the production of hydrogen for multi-day or even seasonal storage in the STM, the approach taken for gas storage could be repeated for electrolysers. This approach uses the LTM to take a view on how storage is used using the coarse temporal granularity it sees, capturing multi day and seasonal storage cycles. The daily storage levels in the LTM are then passed to the STM in the form of end of day volume constraints that STM storage technologies must obey.

This approach could be extended to hydrogen storage technologies. This would ensure: medium and long term hydrogen storage cycles were observed in the STM consistent with the LTM; both electrolysers and storage will continue to have within day flexibility to meet the STM hourly view of demand and provide additional system services.

A.8 Improved performance

A.8.1 Rationale

The SFM is highly complex model, with a huge number of degrees of freedom and multiple repetition through iteration. Despite the partial decoupling of the LTM and STM, the SFM does take a long time to run, even when using a high performance multicore modelling machine – approximately 1 day per iteration for the deterministic results presented in this report, or nearly 2 weeks for the Base scenario.

Performance is a limiting factor for the tool, as it:

- Makes it slower and harder to fix bugs or data errors
- Reduces the number of analyses that can be performed, reducing the usefulness of the tool
- Reduces the horizon over which Monte-Carlo runs can reasonably be performed
- Limits the number of potential enhancements that can be made to the model, as many will increase the complexity and therefore further degrade the performance

A.8.2 How it could be included in a future version of SFM

There are a number of ways that performance could be improved, some related to direct performance tweaking and some through simplifications that will alter the results:

- Streamlining of SQL pre-processing algorithms
  - Between the LTM and STM (and vice versa) SQL is used to perform a number of calculations that take outputs from one module and convert them to inputs for the other module. This can take a significant period of time (~20% of total run time), which gets longer in later iterations due to the multi-iteration calculation of the PCF.
  - The worst performing SQL Views and stored procedures have been tweaked for performance already, but there are likely further performance gains to be found here
- Parallelisation of STM calculation
  - The STM uses 5 characteristic days for each year being solved. In the deterministic results presented here this means 20 independent characteristic weeks, which are solved sequentially.
  - It is possible to build a framework that uses a computing cluster, and sends each STM characteristic week to a different machine to be solved before gathering the results at a single master machine
  - This would give huge performance gains, but require reasonable development time and, crucially, access to a large number of AIMMS licences
- Faster convergence through heuristics
  - If the stopping criteria can be met in fewer iterations, the run time can be reduced linearly
  - It may be possible to define heuristics (with values calculated from previous iterations) that "guide" the SFM to a stable solution more quickly the current approach based primarily on reducing unserved energy at lowest cost
  - The difficulty here is in deciding on a suitable heuristic which improves the convergence behaviour but does not pre-define the type of solution the model should find
- Simplification of data set
  - The current R1.1 model has huge complexity in part due to the level of granularity across multiple dimension, particularly geographical nodes and technologies
    - The current 23 nodes could be collapsed into say 10, with an exponential decrease in run time
    - Currently over 600 supply, demand, storage and network technologies are represented in the model. Many of these are variants on the same base technology and could reasonably be aggregated to improved performance
  - While this could give a significant improvement to the model, it would alter the results and insights from the model and so care would need to be taken when choosing which technologies to simplify

Appendix B Data Items

B.1 Storage Technology costs

The following table represents the marginal costs in power and volume terms for the storage technologies that have been added (compared to ESME 4.1). Sources include Oxford Institute of Energy Studies, SANDIA, Powervault, ENEA, UKERC, IRENA, E4Tech/CCC

Table 6 - Storage technology cost table (in volume and power terms)

Technology	*Volume (£/kWh)*		*Power (£/kW)*		*Round trip efficiency (%)*
Year	**2020**	**2050**	**2020**	**2050**	
Battery - Advanced Pb-Acid	1049.56	777.78	688.82	510.45	89%
Battery - Li-ion - Home	297.97	140.76	983.31	464.49	89%
Building Hot Water - Phase Change Material	23.04	17.08	-	-	98.5%*
Building Hot Water - Thermochemical	35.72	16.87	-	-	99.4%*
Building Space Heat - Phase Change Material	23.04	17.08	-	-	98.5%*
Building Space Heat - Thermochemical	35.72	16.87	-	-	99.4%*
Flywheel Storage	3024.12	2241.04	507.31	375.94	85%
Hydrogen bulk storage - Compressed	30.04	30.04	-	-	97.5%
Hydrogen bulk storage - Liquid	0.78	0.78	-	-	70%

Liquid Air Storage	0.00	0.00	1423.29	672.33	65%
Super Capacitor Storage	10834.42	8028.89	216.69	160.58	91.5%
Superconducting Magnetic Energy Storage	10834.42	8028.89	216.69	160.58	95%
Underground Thermal Energy Storage	2.98	2.98	-	-	70%

* Note that heat storage efficiency is measured as the volume remaining in storage after 1 hour

B.2 Technologies added as part of this project

The Storage and Flexibility Model has been developed using ESME v4.1 as its starting point. A number of technologies were added to the ESME v4.1 data set to develop R1.1 of the SFM, to give a richer representation of where system flexibility may come from.

The following table includes all technologies added as part of the current project.

Table 7 - Storage technology cost table (in volume and power terms)

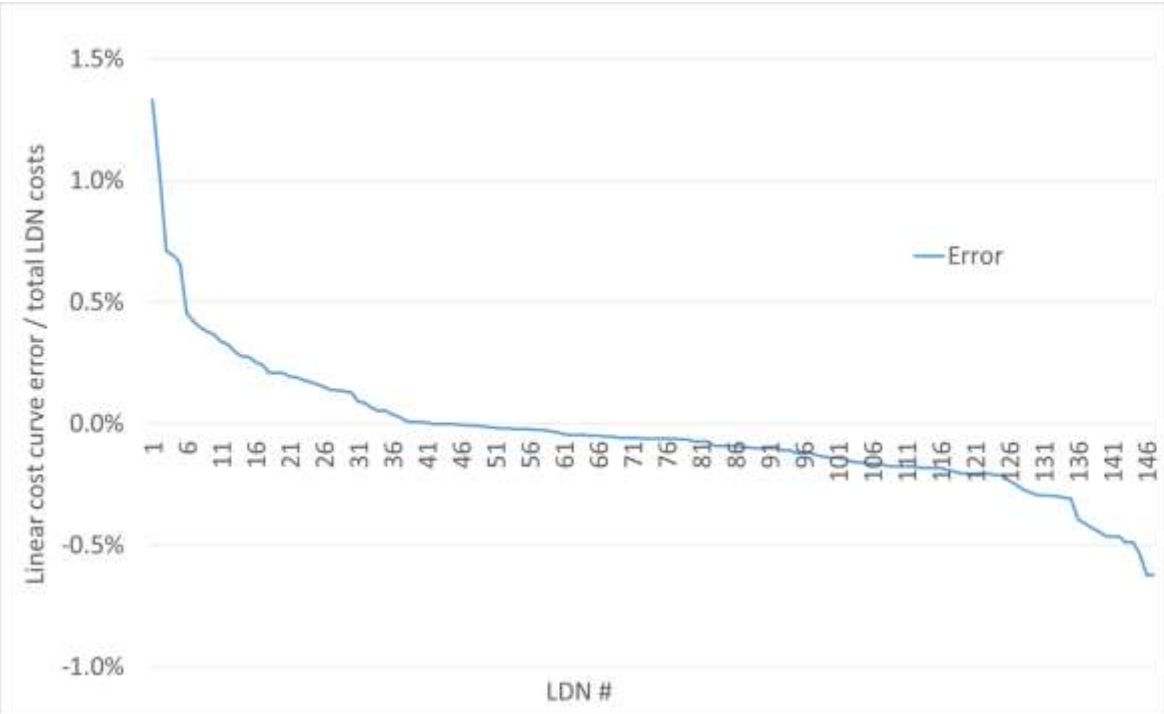
Technology name	Technology Type	Technology Description
Power to SNG	Conversion - Electricity to Gas	Conversion technology, produces gas from electricity
DSR_Industry	DSR	Industrial load shedding DSR
Backstop energy provider	Dummy backstop generator	Dummy generator used to supply energy if other technology capacity not sufficient
Backstop energy service provider	Dummy backstop generator	Dummy generator used to supply energy services if other technology capacity not sufficient
Backstop space heat provider	Dummy backstop generator	Dummy generator used to supply space heat if other technology capacity not sufficient
Interconnector Belgium-Netherlands (Electricity)	Interconnector - Electricity	Generic Electricity Interconnector - GB and Belgium-Netherlands
Interconnector Denmark (Electricity)	Interconnector - Electricity	Generic Electricity Interconnector - GB and Denmark
Interconnector France HVDC (Electricity)	Interconnector - Electricity	Generic Electricity Interconnector - GB and France
Interconnector IFA (Electricity)	Interconnector - Electricity	Existing Electricity Interconnector - GB and France
Interconnector Ireland HVDC (Electricity)	Interconnector - Electricity	Generic Electricity Interconnector - GB and Republic of Ireland
Interconnector Moyle (Electricity)	Interconnector - Electricity	Existing Electricity Interconnector - GB and Northern Ireland
Interconnector Norway (Electricity)	Interconnector - Electricity	Generic Electricity Interconnector - GB and Norway
Interconnector BBL (Gas)	Interconnector - Gas	Existing Gas Interconnector - GB and the Netherlands
Interconnector IUK (Gas)	Interconnector - Gas	Existing Gas Interconnector - GB and Belgium
Interconnector Moffat (Gas)	Interconnector - Gas	Existing Gas Interconnector - GB and Republic of Ireland
Electricity Distribution Network	Network - Electricity	Electricity Distribution Network
Gas Distribution Network	Network - Gas	Gas Distribution Network

Gas NCS Entry Point	Network - Gas	Entry point to GB gas network (NTS) from Norwegian Continental Shelf
Gas UKCS Entry Point	Network - Gas	Entry point to GB gas network (NTS) from UK Continental Shelf
LNG Regasification Terminal	Network - Gas	Entry point to GB gas network (NTS) from LNG imports
Battery - Advanced Pb-Acid	Storage - Electricity	Grid scale advanced lead-acid battery
Battery - Li-ion - Home	Storage - Electricity	Home scale Li-Ion battery (eg "PowerWall")
Flywheel Storage	Storage - Electricity	Flywheel mechanical storage for electricity
Liquid Air Storage	Storage - Electricity	Electricity storage through cooling air into liquid then expanding through turbine
Gas Long Range Storage	Storage - Gas	Long range storage for gas
Gas Medium Range Storage	Storage - Gas	Medium range storage for gas
Gas Short Range Storage	Storage - Gas	Short range storage for gas
Gas T Linepack	Storage - Gas	Linepack storage available from pressure fluctuations in gas network
Building Hot Water - Phase Change Material	Storage - Heat	Building level heat storage for hot water - Phase Change Material
Building Hot Water - Thermochemical	Storage - Heat	Building level heat storage for hot water - Thermochemical
Building Space Heat - Phase Change Material	Storage - Heat	Building level heat storage for space heat - Phase Change Material
Building Space Heat - Thermochemical	Storage - Heat	Building level heat storage for space heat - Thermochemical
Underground Thermal Energy Storage	Storage - Heat	Underground heat storage for network heat
Hydrogen bulk storage - Compressed	Storage - Hydrogen	Large scale hydrogen storage through compressed H2 gas
Hydrogen T Linepack	Storage - Hydrogen	Linepack storage available from pressure fluctuations in hydrogen network

B.3 Gap analysis for LDN network costing

A gap analysis has been performed between the full piecewise linear representation of LDNs (see section 2.3.7) and the simple single linear representation used in the analysis. For each LDN in the SFM the capacity in each year has been used to calculate the implied reinforcement cost under the piecewise linear and simple linear representations, and the error between these found. Figure 82 shows the error over all LDN capacities available, scaled by the total LDN reinforcement cost of the system. While there is variation in the magnitude and direction of the error, across all LDNs the total error is -5% of total LDN costs. Given that LDN costs represent only 1% of total system costs, an error of 5% in LDN costs introduced through the linear cost curve simplification is deemed acceptable.

Figure 82 Error in LDN costs due to linear simplification of cost curves



B.4 Energy service requirement scalars

Electricity services are included in the SFM through linear constraints, as described in Section 2.3.5. These constraints calculate the requirement for, and the provision of, system services, in an endogenous manner.

The linear representation of each requirement has been developed as part of this project by performing a regression on operational data.

The resulting scalars are as follows:

Frequency Containment

FC_req = **1.8** * Largest-in-feed-loss (MW) + **-0.0025** * Demand (MW) + **-4.5** * System Inertia (GVAs)

[This is for headroom, for footroom the Largest-in-feed-loss is replaced with Largest-demand-loss]

Frequency Replacement

FR_req = **1.3** * Largest-in-feed-loss (MW) + **-0.013** * Demand (MW) + **-0.34** * System Inertia (GVAs)

[This is for headroom, for footroom the Largest-in-feed-loss is replaced with Largest-demand-loss]

Reserve Replacement

RR_req = **19.25%** * Wind (MW) + **24.9%** * Solar (MW) + **4.5%** * Demand (MW)
+ Largest-in-feed-loss (MW)

Appendix C Scenarios – arriving at results

C.1.1 Coupling iterations

A key innovation in the SFM is the separation of the problem into two coupled modules, the LTM and STM. A single "run" of the SFM comprises of multiple iterations of the LTM and STM, until the stopping criteria are met – stable system costs and minimal unserved energy (with tolerances as defined by the user).

In this subsection the key metrics are described, as they change over successive coupling iterations. The results here are not instructive in analysing a decarbonised pathway (the purpose of the SFM) but rather are included to show how the SFM is working and the behaviour it exhibits in reaching a solution. The results of the final coupling iteration are explored in more detail in section 3.

Base Scenario

The stopping criteria for the model are currently when total system costs change by less than 0.1% in successive iterations and unserved energy is less than 1% for each energy vector.

Figure 83 shows the system costs as they evolve over successive coupling iterations. It can be seen that while there is initially some movement these quickly stabilise.

Figure 83 System costs evolution over coupling iterations, Base

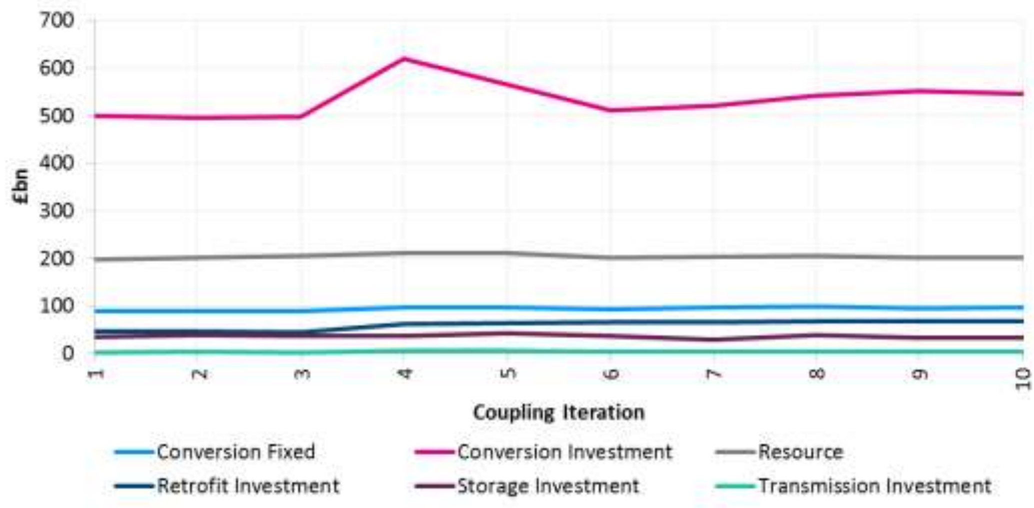


Figure 84 shows the unserved energy as successive iterations are completed. Initially there is quite high unserved energy, which is gradually reduced as the model refines the capacity required to meet demand as represented at an hourly level in the STM. In 2020 unserved energy is eliminated completely, however in 2050 the solution is harder due to a tight carbon constraint and some unserved energy in the heat sector remains. This unserved energy is less than 1% of heat demand and is deemed acceptable for the purposes of a multi-vector model.

Figure 84 Unserved energy evolution over coupling iterations, Base

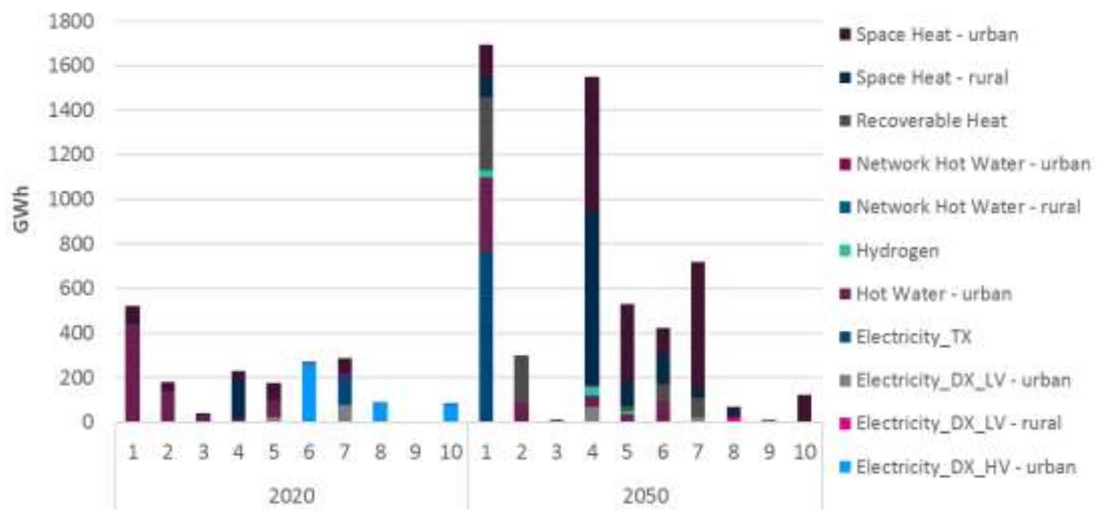


Figure 85 Electricity generation capacity evolution over coupling iterations

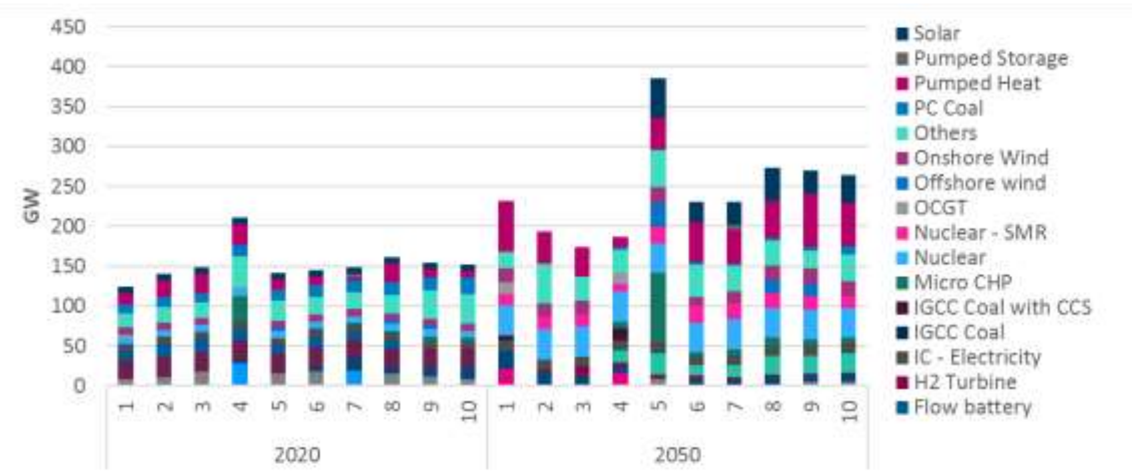


Figure 85 shows the electricity capacity over multiple iterations. It can be seen that the model initially "tries out" a number of different solutions before stabilising on a high-level design. The capacity decisions are more stable in 2020 than 2050 because a) there is more existing capacity that is present (reducing optionality in the solution in terms of the additional new build needed) and b) the lack of a binding carbon constraint makes the solution easier to find. It should be noted that electricity proves the most unstable vector across iterations – in other energy vectors there are fewer choices to be made and a stable solution is found in fewer iterations. While the electricity capacities shown in Figure 85 are not completely stable at the time of the final iteration, they are stable enough that the total system costs differ by < 0.1% and so meet the stopping criteria. The technologies that show the largest swings in capacity in the final few iterations are CCGTs (both with and without CCS) and OCGTs.

No CCS Scenario

In the No CCS scenario, the lack of CCS technologies makes the solution harder to solve. This can be seen in Figure 86, where system costs show greater variation across coupling iterations as the SFM tries more radically different solutions before finding a solution that meets the stopping criteria.

This can be seen in Figure 87 and Figure 88, which shows the evolution of unserved energy and electricity capacity respectively under the No CCS scenario. It can be seen that there is greater variation between successive iterations in the No CCS scenario than in the Base scenario.

It takes the No CCS scenario slightly fewer iterations to reach a stable solution (8 iterations rather than 10 in Base scenario). This is may be due to there being fewer options (ie CCS technologies removed) in the solution space for the No CCS scenario.

Figure 86 System costs evolution over coupling iterations, No CCS

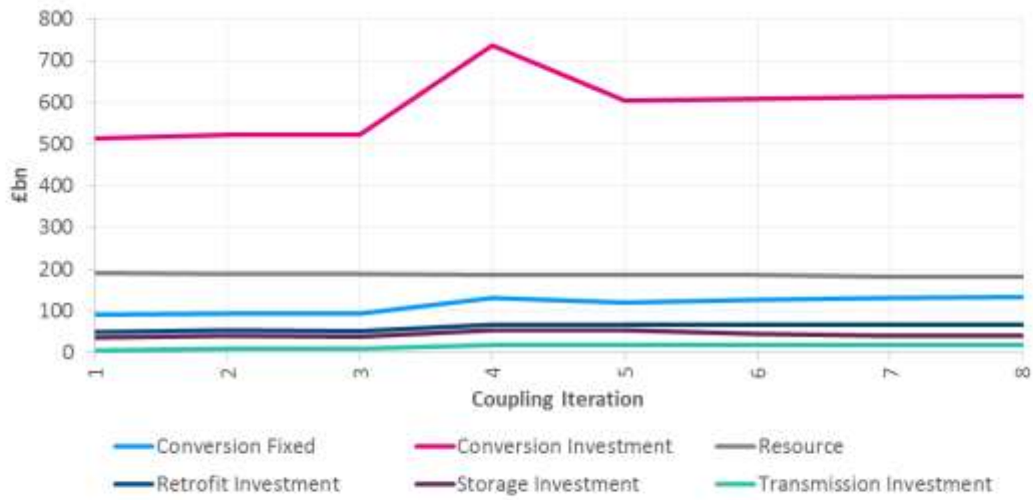


Figure 87 Unserved energy evolution over coupling iterations, No CCS

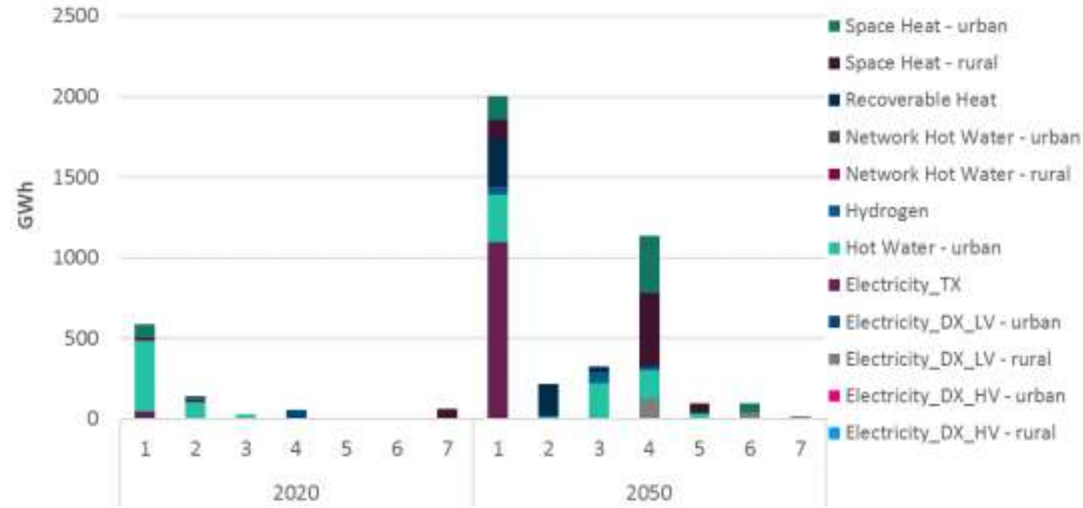


Figure 88 Electricity generation capacity evolution over coupling iterations, No CCS