OWIC 'Solving the Integration Challenge' Task Force

Workstream 'A' Final Report
Chapter 4
Storage and Flexibility Services Options

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23/09/2020	2.2	Final version with minor amendments following feedback.

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Contents

List of Acronyms

Acronym	Meaning
ASHP	Air Source Heat Pump
CAES	Compressed Air Energy Storage
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
DHN	District Heat Network
ESME	Energy Systems Modelling Environment
GSHP	Ground Source Heat Pump
LSHP	Large Scale Heat Pump (marine)
LCoE	Levelised Cost of Energy
LTM	Long Term Module
NaS	Sodium Sulphur (battery)
OCGT	Open-Cycle Gas Turbine
OSW	Offshore Wind
SFM	Storage and Flexibility Model
SMR	Dependent on context, either: Steam Methane Reformation, or nuclear Small Modular Reactor
STM	Short Term Module

4. Storage and Flexibility Services Options

4.1. Executive Summary

This document is Chapter 4 of the report from Workstream A of the 'Solving the Integration Challenge' project. It builds upon the whole energy system modelling analysis carried out in Task 1, as reported in Chapter 3.

This Chapter 4 reports the analysis carried out in Task 2, which focuses on the impact of increased offshore wind deployment on the need for flexibility within a Net Zero energy system, and on the options for provision of the required storage and flexibility services in a multi-vector, whole-system context.

Two scenarios were modelled using ESC's Storage and Flexibility Model (SFM). SFM is a design, not forecasting tool and so these scenarios represent least-cost designs of the energy system and not projections:

- In the first, the level of OSW deployment is unspecified ('unforced'), and is selected by the model based on least system cost.
- In the second, 125GW of OSW is specified ('forced') as being deployed into the system by 2050.

This analysis finds that due to its relatively low cost and low carbon credentials, OSW plays a significant role out to 2050 under both scenarios, with 70GW being deployed in the first scenario (as a result of optimisation without any specified deployment level).

Significant back-up capacity is required under both scenarios to manage rare low-renewable weeks, but the need for this capacity is greater in the higher wind scenario due to its greater reliance on offshore wind and its low levels of nuclear deployment. Although this back-up capacity is part of a least-cost system, its infrequent use leads to difficulties in presenting a viable commercial business case when considering existing markets.

As well as back-up capacity, extensive storage and flexibility are required in both scenarios across all vectors, with electric, thermal and gaseous storage (including demand side management from domestic thermal storage) all being deployed alongside interconnectors and peaking plant. Typically, more flexibility is needed in the winter when peak demand is greatest, although higher levels of wind slightly reduce this need.

This analysis found that there is a cost increase of £9bn (3%) by 2050 for the higher wind scenario compared to the lower wind scenario. However, this is relatively small when comparing total system cost between two scenarios with radically different electricity system designs. Further work could provide additional benefit by carrying out more model runs to explore sensitivities – including how small variations in cost and performance of key technologies might affect the overall system cost impact of offshore wind, as well as how this cost differential might change across a range of offshore wind deployment levels.

4.2. Introduction

The variable nature of available wind resource means that to successfully integrate significantly increased volumes of offshore wind (OSW) into the GB energy system an assessment of the consequent storage and flexibility requirements should be considered.

Task 1 provided a starting point to how flexibility and intermittency is managed within the context of this study. However, it also noted that the Energy Systems Modelling Environment (ESME), with a minimum time-slice of 4 hours, does not contain adequate temporal resolution for deep implications of hourly or sub-hourly balancing to be included.

Therefore, in this report Energy Systems Catapults' Storage and Flexibility Model (SFM) is used to assess requirements for storage and flexibility services in the context of highly variable supply and demand. Provision of these services were modelled in a multi-vector, whole-system context, considering whole-system performance and cost.

4.3. Storage and Flexibility Model (SFM)

SFM, like ESME, is a least-cost optimisation national modelling tool. It is a design tool rather than a forecasting tool and as such does not make projections of what the future energy system will look like. Rather, it designs , according to its assumptions, the least-cost, low-carbon energy system by 2050. provides a techno-economic evaluation of energy storage and other sources of flexibility across multiple energy vectors, network levels, geographic regions and timeframes. Detail of these modelled characteristics is provided in Table 1.

Table 1: SFM modelled characteristics

Area of Techno-Economic Evaluation	Modelled Characteristics
Energy vectors	Electricity, hot water, natural gas, hydrogen
Network levels	Transmission level, distribution level (split into high and low voltage for electricity distribution network), behind-the-meter (industry, commercial and domestic)
Geographic regions	11 onshore regions: East, East Midlands, London, North East, North West, Scotland, South East, South West, Wales, West Midlands, Yorkshire and Humber 12 offshore regions: Central North Sea, Channel Islands, Dogger Bank, East Irish Sea, East Scotland, Hebrides, Irish Sea, Lundy, Norfolk, Pentland, Shetlands, Southern North Sea Inter-regional transmission links
Timeframes	Decadal, long-term capacity investment to hourly dispatch with a representation of sub-hourly system services (frequency containment, frequency replacement and reserve replacement)

The complexity of modelling energy storage and flexibility over multiple energy vectors, network levels, geographic regions and timeframes makes it computationally challenging to represent in a single optimisation problem. Therefore, SFM is made up of two individual but hard-linked optimisation modules:

- **Long-term module (LTM):** broadly based on ESME, it makes long-term decadal capacity investment decisions across multiple vectors optimising by least total system cost.
- **Short-term module (STM):** developed for the SFM, it makes short-term dispatch decisions on an hourly timescale with perfect foresight over one day. These decisions are based upon the technical capabilities of technologies and other constraints (e.g. the minimum size of commitment and the ramp rates of thermal generation). The STM allows transfer of energy between vectors on an hourly basis and is underpinned by both gas and electricity demand profiles. It is is least-cost optimised for operational and resource costs over five characteristic weeks; Each characteristic week represents one of the four seasons, as well as a peak week which is broadly based on a "1 in 10 year"[1] worst case (low renewable supply, high demand). The STM also includes a representation of sub-hourly system services for frequency containment/replacement and reserve replacement.

Figure 1 is a high-level illustration of how the two modules are linked into a single model. The SFM first runs the LTM and then the STM to produce one complete iteration, it then continues to iterate until the stopping criteria are met. After each run of the LTM or STM, information is passed to the other module; 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.

There are two stopping criteria which have to be met before the SFM will stop solving: a maximum difference in costs between successive iterations and a maximum threshold for unmet energy demand. Both of these criteria are user-defined and aim to ensure that a stable equilibrium is reached with minimal (if any) unmet demand. The final complete iteration is taken as the model result. More detail of SFM's structure is provided here[2,3].

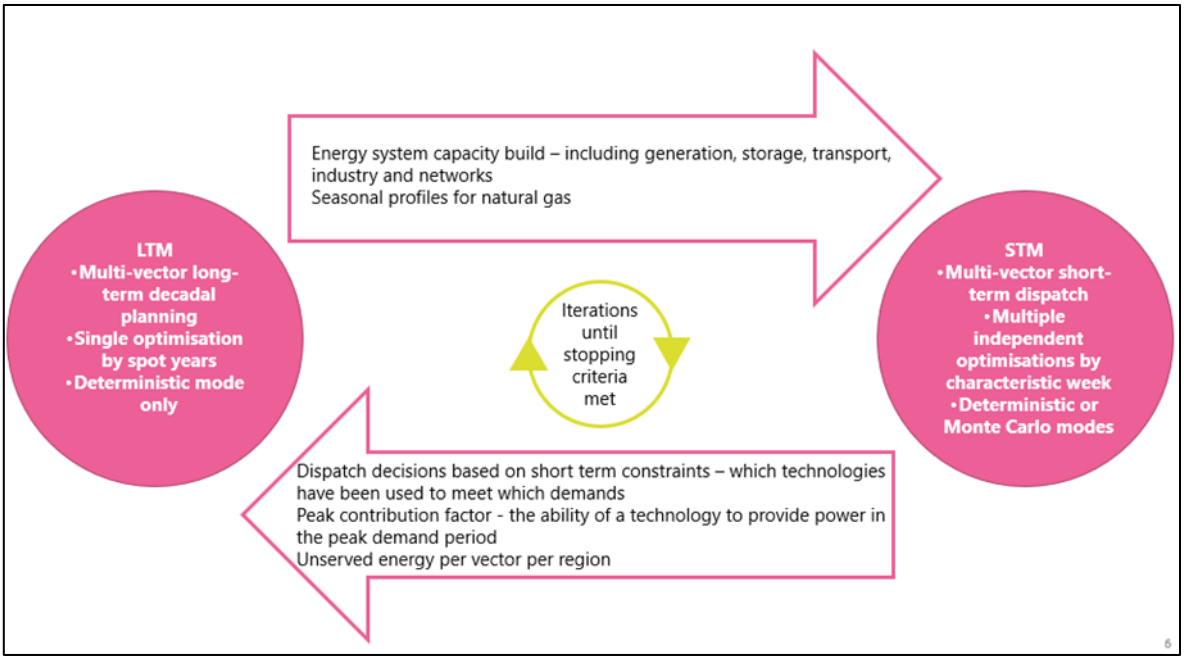

Figure 1: Modular structure of SFM

[1] Storage and flexibility model final project report: https://www.eti.co.uk/programmes/energy-storage-distribution/storage-flexibility-modelling
[2] https://www.eti.co.uk/programmes/energy-storage-distribution/storage-flexibility-modelling

[3] https://es.catapult.org.uk/reports/balancing-supply-and-demand/

4.3.1. SFM Strengths and Weaknesses

One of SFMs key strengths is its whole system coverage, meaning that decarbonisation efforts in completely different parts of the energy system are placed on equal terms (see Task 1).

An additional strength of SFM is its focus on storage and flexibility. All large whole-system models must compromise on detail in places, but by focusing on one area SFM can ensure that all pertinent features related to storage and flexibility are included.

Conversely this does mean there are other areas where less detail is given; for example, when compared to ESME, SFM considers GB not the UK and has decadal time steps rather than every 5 years as in ESME. It should also be noted, as discussed earlier in this section 4.3, that (as with ESME) the results of SFM should be considered as scenarios, rather than forecasts, which provide useful insights into potential, but not predicted, future energy systems.

4.3.2. SFM and ESME Comparison

It is outside the scope of the report to compare SFM and ESME in detail, which has been done here[3]. However, an overview of the similarities and differences is important for interpretation of the results from SFM alongside those from ESME.

The assumptions that are consistent with ESME include:

- End user demand assumptions
- Technology assumptions (in terms of cost and build rate and quantity constraints)
- Carbon emission constraints (scaled to GB rather than UK)
- Policy neutrality (see Task 1).

To allow for a more detailed assessment of storage and flexibility, several new assumptions have also been developed as part of SFM. These are focused on those areas which have a direct impact on storage and flexibility:

- Additional storage technologies and their associated costs
- Dynamic dispatch assumptions for supply technologies e.g. ramp-down and ramp-up rate, minimum on/off times, minimum stable level
- Parameters for the endogenous calculation of the requirement for, and provision of, energy services
- Assumptions on managed charging of electric vehicles (EVs), home space heat storage, and industrial load shedding Demand Side Response (DSR). These assumptions are on an hourly basis and include constraints such as maximum charging rate for EVs and minimum price which industrial users must receive to shed load.
- Local Distribution Network (LDN) reinforcement cost curves.

There are also structural differences between SFM and ESME, described below in Table 2. Fundamentally this is because, unlike ESME, SFM has an hourly view of the dispatch of supply technologies and a representation of the need for system services – both of which have a significant impact on the requirements for storage and flexibility. However, as discussed above this results in trade-offs in other areas.

Table 2: ESME and SFM comparison

	ESME	**SFM**
Time steps	5-year build periods A year represented by 2 seasons (summer, winter) and 5 intraday periods (overnight, morning, mid-day, early evening, late evening)	10-year build periods A year represented by 5 seasons (spring, summer, autumn, winter, peak), and hourly intraday periods
Spatial resolution	12 onshore regions (former English Government Office Regions and devolved nations), 13 offshore regions	11 onshore regions (former English Government Office Regions and devolved nations excluding N. Ireland), 12 offshore regions
Network levels	Electrical transmission and distribution network, gas transmission network	More granular (includes urban and rural) transmission and distribution network for gas and electricity. Electricity distribution network is further broken down into high and low voltage
Vectors	Electricity, hot water, natural gas, hydrogen	Electricity, hot water, natural gas, hydrogen
System Services	Not included	Provides a representation of headroom requirements for frequency containment, frequency replacement and reserve replacement. Also includes technical constraints on technologies ability to meet these services e.g. ramp rates.
CO_2 and other GHGs	Accounts for all GHGs	Only constrained for CO_2 emissions although expected pathway of other emissions are taken into account when setting this constraint.

4.4. Scenarios

SFM is a less mature model than ESME and performance improvements are still ongoing. One area where improvement was needed was to reduce the solving time of SFM; this was completed at a relatively late stage of the project. Therefore, within the constraints of the project timescale, only two scenarios were budgeted and tested in SFM. Nevertheless, these scenarios provide valuable insights into the role of storage and flexibility under two diverse OSW deployment pathways.

These two scenarios, FA-SFM-125 and FA-SFM-UNF, are equivalent to those similarly named ESME scenarios described in Task 1 and are summarised below in Table 3.

The assumptions in the two scenarios are the same except for the specified minimum OSW deployment level. Therefore, comparison of these scenarios will explore the impact of varying levels of OSW deployment on the flexibility needs of the energy system.

Table 3: Scenario Assumptions

	FA-SFM-UNF	FA-SFM-125
Offshore wind deployment	**OSW deployment is unspecified ('unforced')**, and deployment levels are selected by SFM based on least system cost.	**125GW OSW is specified ('forced')** as being deployed into the system by 2050.
Underlying assumptions	ESME Further Ambition (see Task 1).	ESME Further Ambition (see Task 1).
Nuclear Small Modular Reactor (SMR) deployment	No SMR deployment assumed.	No SMR deployment assumed.

As discussed in Task 1, the Further Ambition scenarios do not reach 'true net zero'. The Further Ambition pathway has emissions which are as close to net zero as is achievable without the speculative options set out within the Alternative Net Zero pathway.

In both pathways, accounting for emissions outside the energy system (e.g. agriculture, peatland etc) results in a net-negative emissions target for the energy system itself by 2050. Under Alternative Net Zero, the speculative measures provide some carbon headroom for the energy system (by enabling further carbon reduction both in the energy system and critically in other sectors). However, under Further Ambition these speculative measures are not available and the system is more 'carbon stressed'. Further Ambition therefore has a more onerous (greater net-negative) emissions target for the energy system itself than Alternative Net Zero (which has to meet net zero but has speculative measures available within it).

For the purpose of analysing flexibility it was felt prudent, given budget constraints, to investigate the likely 'worst case'.

Thus the analysis has focussed on the impact of varying levels of OSW deployment, using the Further Ambition scenarios above. The direct comparison of the Unforced and 125GW scenarios (with otherwise comparable conditions) enables study of the impact arising from significantly increased OSW – this being the primary objective of Workstream A and therefore the scoping priority.

Further work in future is recommended to explore the Alternative Net Zero scenarios in detail. However, initial assessment indicates that in fact the ANZ scenarios are not likely to change the requirements for storage and flexibility particularly greatly, and may potentially reduce them (since thermal generation with higher capture rate CCS may reduce the system's need for flexibility).

4.5. Results – Power Sector

Key results:

- OSW plays a significant role out to 2050 under both scenarios, with 70GW being deployed in the lower wind scenario (FA-SFM-UNF), as a result of optimisation without any specified deployment level.
- Just over 30% of wind is curtailed across both scenarios.
- By forcing an increased deployment of offshore wind (to 125GW), there is a reduction in nuclear deployment and consequently the baseload it provides.
- The need for frequency response reduces in 2050 under both scenarios, largely due to the increase in electric demand (see Appendix A for how frequency response is calculated).
- The requirement for reserve replacement increases substantially under both scenarios, up to a maximum of 28GW under FA-SFM-UNF and 34GW under FA-SFM-125 by 2050. This is due to the increase in renewable generation hence the larger requirement in the high wind scenario.
- Electrical storage is high by 2050 under both scenarios, although FA-SFM-UNF sees a fractionally higher deployment of 78GW/333GWh compared to 72GW/275GWh under FA-SFM-125. Electrical storage is used to balance supply and demand predominantly over the course of a day, with battery storage by far the most preferred technology.

Figures 2 and 3 (overleaf) show the installed electricity capacity and annual generation respectively for each scenario in 2030 and 2050. Under both scenarios there is a significant increase in electricity demand in 2050, largely due to the electrification of heat and transport.

Under FA-SFM-UNF, just under 70GW of OSW is installed by 2050, whereas under FA-FM-125 125GW is specified as a minimum deployment (i.e. 'forced' into the system).

In FA-SFM-UNF, thermal[4] generation is the largest component of installed capacity by 2050, with 80GW representing 30% of total electric generation capacity, although it provides no generation. This is due to the 'peak week' in SFM (see section 4.3.1), which is a test condition designed to ensure enough capacity is present to meet demand during periods of low renewable supply, and broadly represents a "1 in 10 year" worst case (low renewable supply, high demand). As these periods occur rarely, capacity used only in this week does not contribute to annual generation.

The dispatch of electricity generation is discussed in more detail in section 4.5.1, where Figure 4 shows that maximum demand during the peak week is almost 180GW. With no wind or solar PV available at this point and just under 40GW of nuclear capacity deployed there remains a maximum shortfall of 140GW and a total shortfall of ~1200GWh over the week. Interconnectors and energy storage, which are discussed in following sections, contribute significantly to reducing this deficit but around 80GW remains.

Thermal generation (predominantly CCGT and OCGT) has relatively cheap capital costs compared to other options, and due to the rare operation of this thermal generation there is little impact on emissions targets even without CCS. However, although this results in the least cost to the energy

[4] In this analysis thermal generation excludes generation with Carbon Capture and Storage (which is identified separately) but includes generation powered by gas (CCGT and OCGT), coal, biomass, as well as waste incineration and CHP.

system, the rare operation of thermal generation raises questions around commercial viability under current market structures, with these plants likely to need some form of policy support (for example in a strategic reserve market) to operate. This is explored further in Task 4, while Task 5 recommends further work to understand how the system value of deploying these assets compares to the cost of the likely policy support. These thermal generation assets are not used during the other modelled weeks due to their resultant CO_2 emissions and the lack of need due to high renewable deployment, which is usually available.

Alongside OSW, nuclear generation (37GW, 289TWh), and to a lesser extent onshore wind (19GW, 47GWh) and Solar PV (31GW, 29TWh), also make contributions to the annual electricity supply in FA-SFM-UNF.

As in Task 1, it is typical for a mixture of solar PV, wind (offshore and onshore) and nuclear power to supply electricity in most unconstrained simulations. This mix allows the supply and demand in each modelled week to be more readily balanced – for example, within this scenario the higher average load factor for solar PV in the summer complements the lower load factor for wind (compared to winter), helping to avoid oversupply in low demand periods such as overnight in summer.

Also, as in Task 1, significantly less nuclear power is deployed by 2050 under FA SFM-125 (8GW, 37TWh) as the capacity of OSW increases. It is difficult to de-load nuclear, and this is represented in SFM: the minimum stable level of a nuclear 'unit[5]' is assumed to be 70% of full capacity (so it can run at anything between 70-100% of full capacity) and if turned off completely a unit has a minimum off-time of 48 hours. This leads to any nuclear which is deployed being run at close to constant power and means that changing demand is met by other generation technologies ramping up and down or, in the case of renewable generation, being curtailed. This minimum stable level used for nuclear generation therefore has a potentially significant system impact, and further work to explore this in future is discussed in Task 5.

Although not explored in these results, in a scenario with both high levels of OSW (as in FA-SFM-125) and high levels of nuclear (as in FA-SFM-UNF), it is likely that OSW would often be substantially curtailed since the variability of wind generation is not able to be accommodated by the relatively inflexible nuclear power.

Total renewable capacity is higher under FA-SFM-125 (170GW compared to 130GW in FA-SFM-UNF) and consequently renewable generation is also higher at 643TWh compared to 440TWh. This is mainly due to the increase in OSW deployment, albeit slightly offset by a reduction in onshore wind. Compared to the other technologies deployed under FA-SFM-UNF such as nuclear and solar PV, OSW and onshore wind are broadly similar in terms of their load factors (although OSW is higher) and seasonal variation, and so to an extent compete with each other. When additional OSW is specified in FA-SFM-125 this displaces onshore wind (whose capacity falls from 19GW to 1.5GW).

The extra OSW capacity deployed under FA-SFM-125 might have been expected to release further emissions headroom for CCS plant to provide peak shifting and reduce costs in other areas. However, the extra OSW results in an equivalent increased ability to meet peak demand, so reducing the need for CCS.

[5] A unit is defined as the typical size of a single reactor not an entire nuclear plant which is typically made up of several reactors.

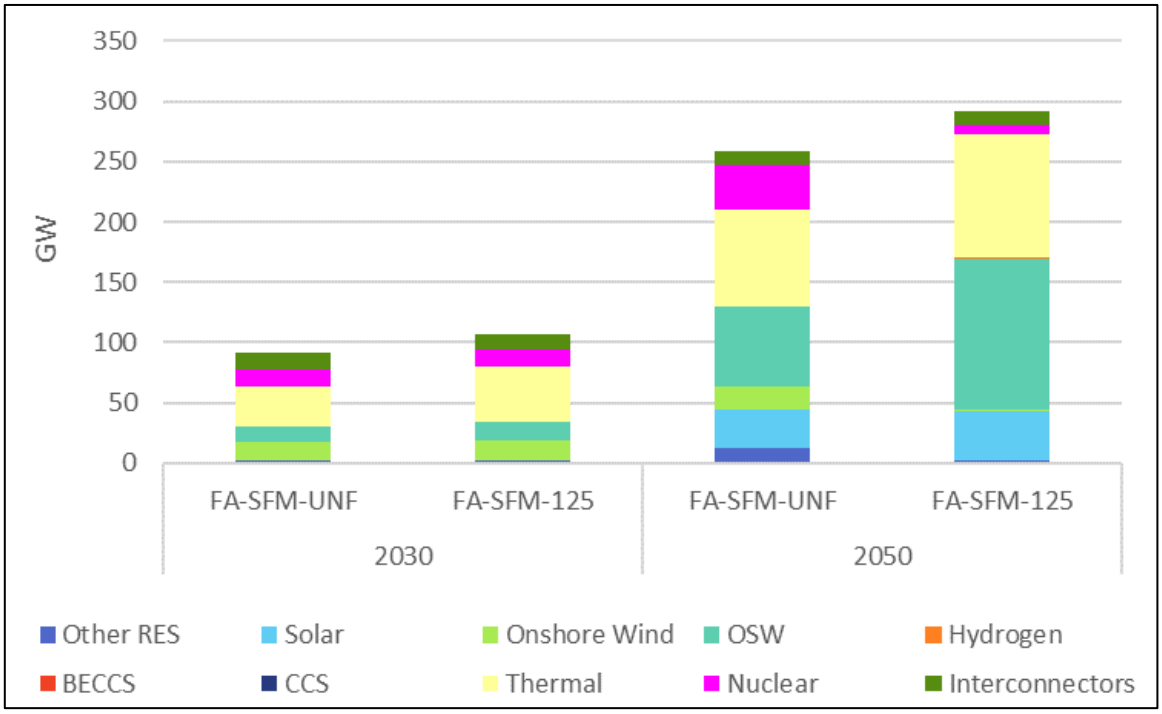

Figure 2: Installed capacity of electricity generation technologies

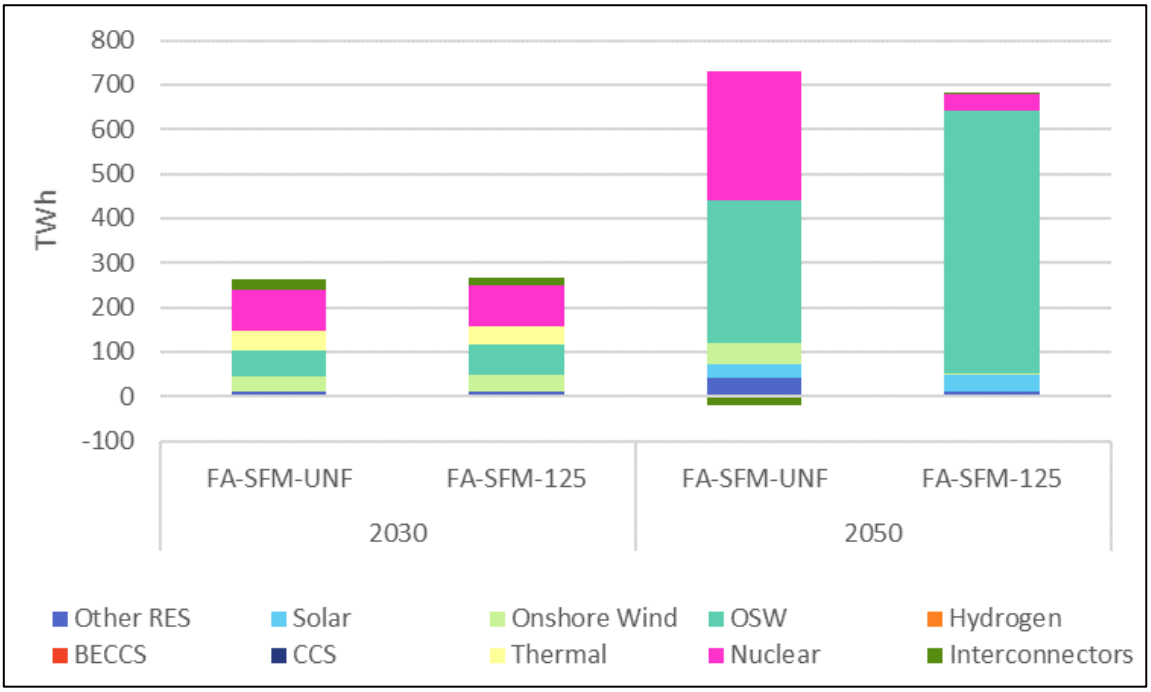

Figure 3: Electricity generation

4.5.1. Dispatch

Figures 4 and 5 (overleaf) show how the electrical capacity in Figure 2 is dispatched for FA-SFM-UNF and FA-SFM-125 respectively. Note that SFM calculates dispatch by hour of week, for each season, but the trends identified generally repeat over a daily cycle. Therefore, to make the figures easier to interpret, only a 48-hr period is shown from 12am Tuesday until 11pm Wednesday - each vertical gridline represents 12 hours. Although SFM represents 5 seasons (four yearly plus peak), Autumn and Spring are variations of trends shown in Winter or Summer, and so for brevity are not included in these two figures. Subsequent figures throughout the report are presented with the same 48-hr timescale and seasons, except where stated otherwise.

The dispatched supply is less than demand when demand is high, and exceeds demand when demand is low. This suggests storage is being used to store electricity when demand is low so that peak demand is met – this is explored in Section 4.5.2. Under both scenarios in 2030 and 2050 nuclear is providing baseload power running at constant output throughout each season, and for peak and winter seasons it is at close to full power; (In summer, nuclear output is dropped slightly in response to the reduction in demand). As discussed above, it is difficult to de-load nuclear and so changing demand is met by other generation technologies ramping up and down or, in the case of renewable generation, being curtailed.

Solar generation provides a significant proportion of supply during the daylight hours of winter and summer for both scenarios. During the peak period no solar PV and only a small amount of wind generation is available due to low resource, but demand is high. Thermal generation is used to meet this demand in 2030 and 2050. Under FA-SFM-125 the substantially lower levels of nuclear deployed due to higher levels of OSW, mean that more thermal generation is required during the peak week to ensure security of supply. This results in the higher thermal capacity of 100GW (35% of total installed electric generation capacity) seen in Figure 2, compared to 80GW in FA-SFM-UNF. As with FA-SFM-UNF, this thermal generation is largely a combination of CCGT and OCGT, both of which have relatively low capital and fixed operational costs.

As discussed above, the peak week is a test condition designed to ensure enough capacity is present to meet demand during periods of low renewable supply, and broadly represents a "1 in 10 year" worst case (low renewable supply, high demand). As such, it is not possible to calculate the exact load factor of this thermal capacity but it is very low. Around 50GW of this capacity is also used to provide systems services, particularly reserve replacement which is discussed further in section 4.5.4. However, even in these cases this generation is used sparingly, either for short periods at a time (less than 1 hour) or in a backup capacity only to be used to cover forecast error or plant outages.

Due to the rare operation of this thermal generation, there is little impact on emissions targets even without CCS. However, its rare operation raises questions around commercial viability (Section 4.5) even under FA-SFM-UNF where the 80GW of capacity results in the least cost to the system.

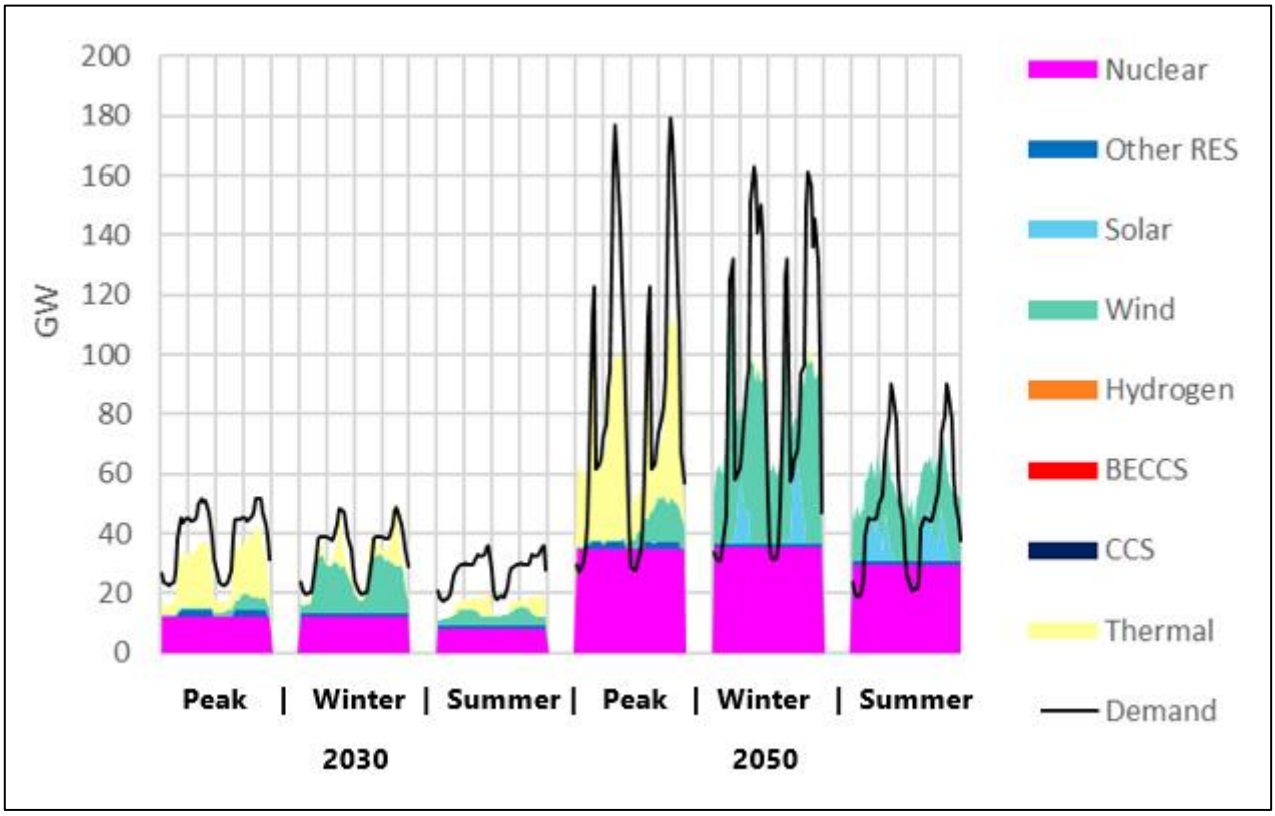

Figure 4: Electrical dispatch FA-SFM-UNF[6]

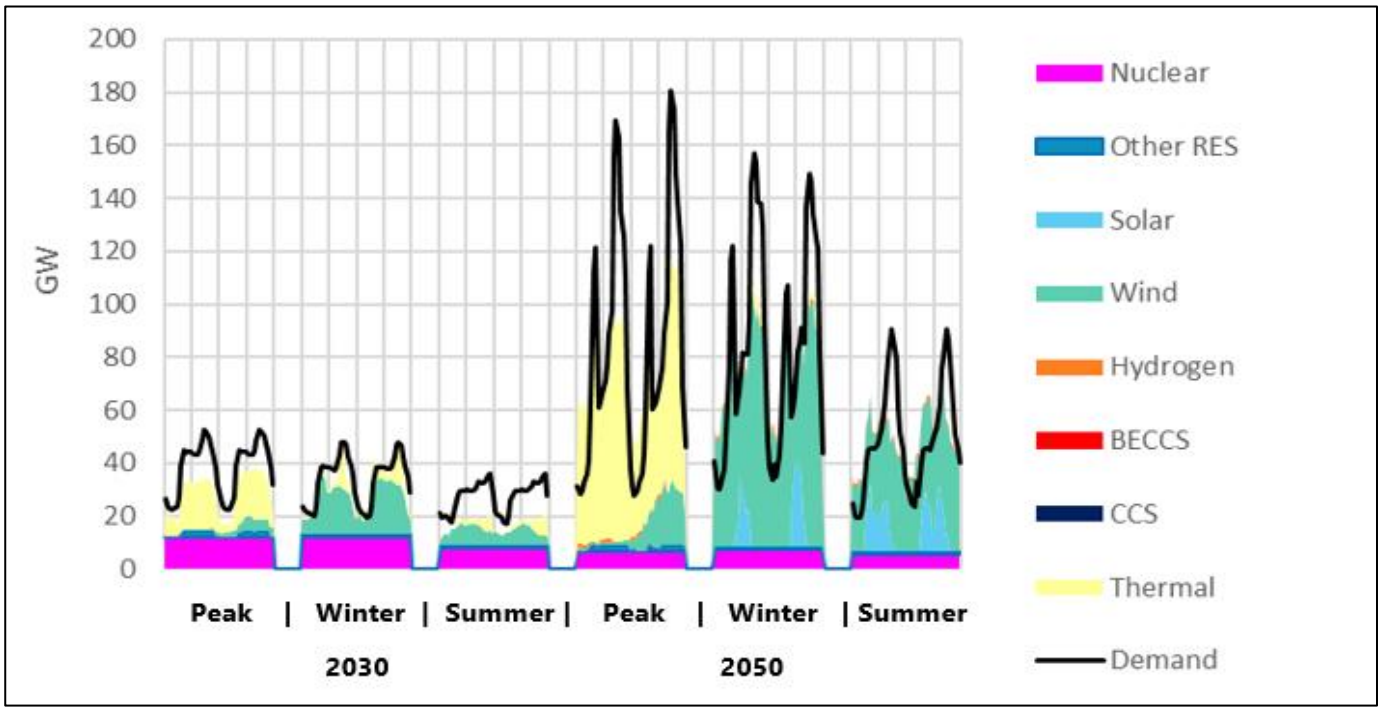

Figure 5: Electrical dispatch FA-SFM-125

[6] Except where stated otherwise, all dispatch charts show periods of 48 hours within each season, with each vertical gridline representing 12 hours.

Figures 6 and 7 show the dispatch of interconnectors in 2030 and 2050 for FA-SFM-UNF and FA-SFM-125 respectively. For both scenarios the utilisation of interconnectors is similar.

In 2050, interconnectors are used to import energy during the peak and winter week almost continuously to meet demand. During the peak week this is due to the low availability of OSW (and solar PV); however, this is not the case during the winter week. Interconnectors are assumed to import carbon free electricity (excess renewables and nuclear) and so are used during winter to help meet Net Zero. During the summer, high levels of solar PV generation combined with lower demand and wind result in significant exporting of electricity, although there is some importing under FA-SFM_125 during the evening peak. This is likely to be due to the absence of solar during the evening, low nuclear and relatively low wind.

Referring to Figure 3, there is a net export by interconnection of ~20TWh/annum by 2050 in FA-SFM-UNF, whilst there is a net import of 2TWh/annum by 2050 in FA-SFM-125. This difference is due to higher levels of export during summer, spring and autumn (spring and autumn not shown) under FA-SFM-UNF due to the increased nuclear generation – which, during periods of low demand, is exported rather than curtailed due to the assumptions around minimum off-time (see earlier in section 4.5).

It should be noted that interconnector capacity is calculated exogenously for SFM, and in 2050 is around 12GW for both scenarios. Given the high utilisation of interconnectors, it is expected, although not proven, that greater interconnector capacity would be selected by SFM if possible. Therefore, further analysis is needed to investigate the benefits of interconnectors.

Crucially, this further work should also examine the assumption that there will be sufficient carbon free electricity available to import, and demand to export, as required. Other European countries may be facing similar conditions (demand and available renewable resource) as the UK at the same time, and so struggle to export low carbon electricity or to import electricity when the UK requires it. On the other hand, the larger geographical area of Europe and its interconnected nature may reduce this risk.

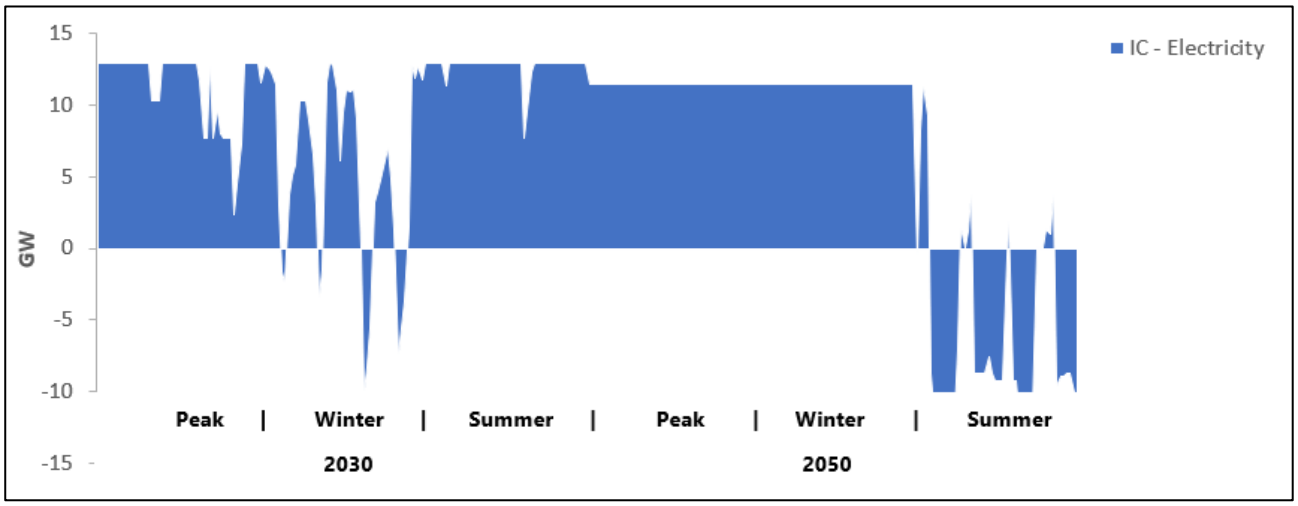

Figure 6: FA-SFM-UNF interconnector dispatch

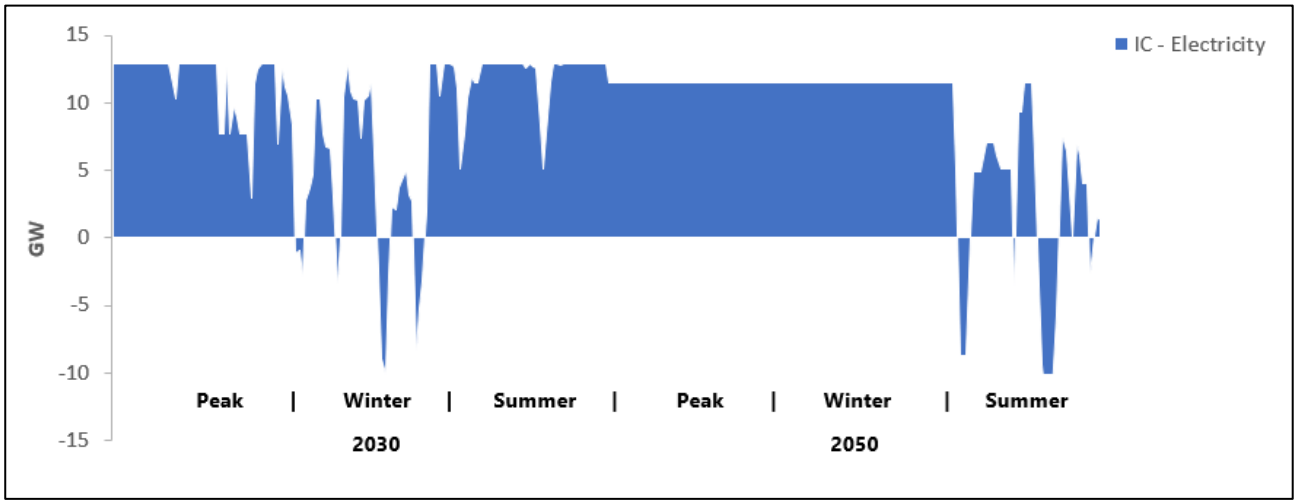

Figure 7: FA-SFM-125 interconnector dispatch

4.5.2. Electrical Storage

Figures 8 and 9 overleaf show the power rating and storage volume respectively of electrical storage technologies for both scenarios in 2030 and 2050. For both scenarios, storage levels (power and capacity) increase between 2030 and 2050, reflecting the large increase in total variable / inflexible electrical generation and increased electrified demand that needs to be balanced in real time.

By 2050 there is more storage in terms of power and capacity in FA-SFM-UNF (78GW, 333GWh) than FA-SFM-125 (72GW, 275GWh). Although the difference is relatively small, it might be expected that FA-SFM-125, with its greater levels of renewable generation, would result in the greatest levels of storage. However, this neglects several points:

1) There are other vectors which can provide storage and flexibility (see 4.6.2 and 4.7.2).
2) Nuclear capacity (which is much higher in FA-SFM-UNF) is also inflexible and so can drive a requirement for storage and flexibility.
3) Higher levels of wind mean the extent to which demand exceeds supply is less, excluding the peak week which is largely covered by thermal generation.

For both scenarios the majority of electricity storage is provided by batteries (predominantly Lithium-ion), with smaller amounts of pumped and thermo-mechanical storage. It is worth noting that these storage technologies generally have a longer discharge duration than batteries (4-24 hours, rather than 1-6 hours), and so they provide more storage capacity for a given rated power; This can be seen in the relative increase in their proportion of capacity (Figure 9) compared to power (Figure 8).

The relatively small uptake of longer duration electricity storage and the reliance on battery storage is due to three factors:

1) Lithium-ion battery storage is assumed to have relatively attractive techno-economic parameters compared to other storage technologies (see Table 4);
2) The requirement for storage is generally only for a few hours at a time to help meet intra-day peak demand; and
3) Longer duration electricity storage is competing with other energy vectors such as natural gas and hydrogen.

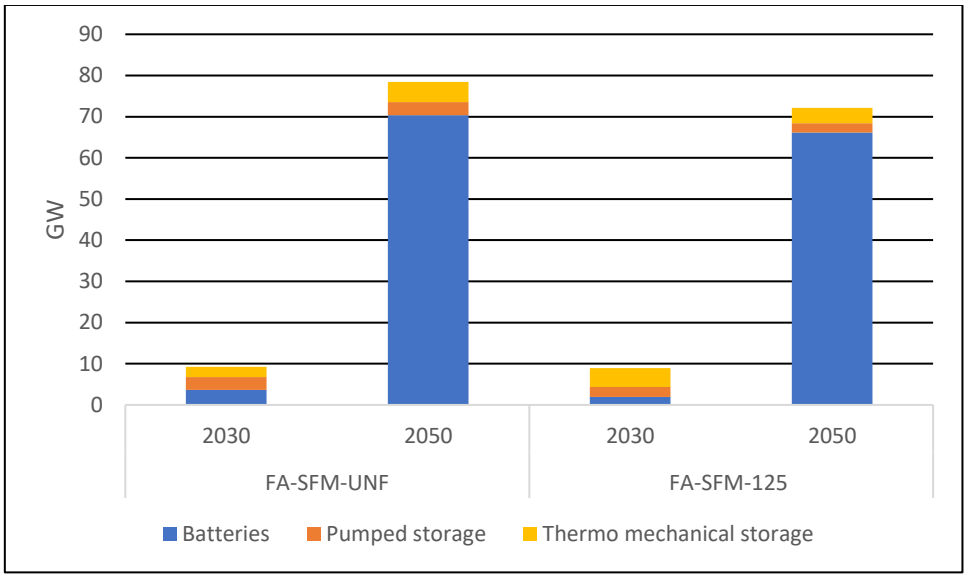

Figure 8: Power rating of electrical storage

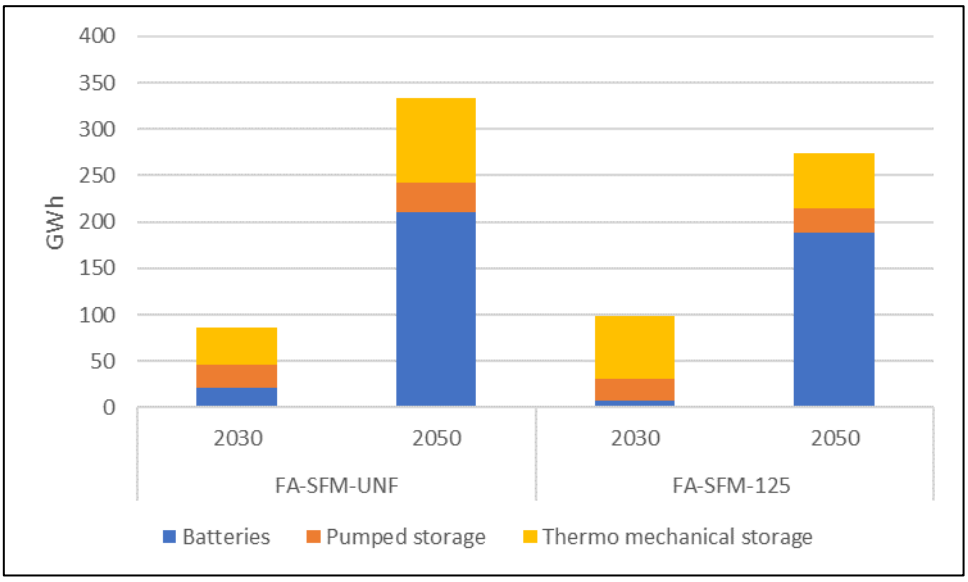

Figure 9: Electrical storage capacity

Table 4: Key storage techno-economic assumptions (in 2050)

Technology	Technology category	Energy cost[7] (£/kWh)	Power cost (£/kW)	Efficiency (%)
Lithium-ion batteries	Batteries	147	99	91%
NaS batteries	Batteries	229	333	75%
Flow batteries	Batteries	252	359	75%
Pumped heat storage	Thermo-mechanical storage	15	512	67%
CAES	Thermo-mechanical storage	10	518	60%
Pumped storage	Pumped storage	78	453	81%

Figures 10 and 11 overleaf show how electrical storage is dispatched for each scenario respectively in 2050, providing more detail on the role which each type of technology provides. For these two figures only, 72 hour periods (rather than 48 hour periods) are shown. 72 hours was required to show the full range of storage technologies dispatched during a given season. Each individual column represents 1 hour, with a vertical gridline every 12 hours.

These confirm that in both cases storage is mainly being dispatched for a few hours at a time (~5-6 hours) at peak periods (namely ~3-9pm and to a lesser extent 7-9am) and being charged at periods of low demand including overnight.

Across both scenarios the greatest storage demand is over the peak week. Due to the low renewable resource over this period, additional storage is required to help meet peak demands. Although the demand for storage during the peak week is similar for each scenario, the relative increase from winter to peak – which represents the additional storage dispatched only in the peak week – is much higher for FA-SFM-125 at 18GW compared to 7GW for FA-SFM-UNF. This is due to the higher storage requirement of FA-SFM-UNF during the winter (due to the three reasons discussed above) and the relative additional need for storage in the peak week under FA-SFM-125 due to the low level of nuclear. This again raises questions around the commercial viability of assets which are generating infrequently.

[7] Energy storage is quantified in terms of both its power (kW) and storage capacity (kWh). Energy and power costs refer to those components of the technology which relate to the power and energy respectively.

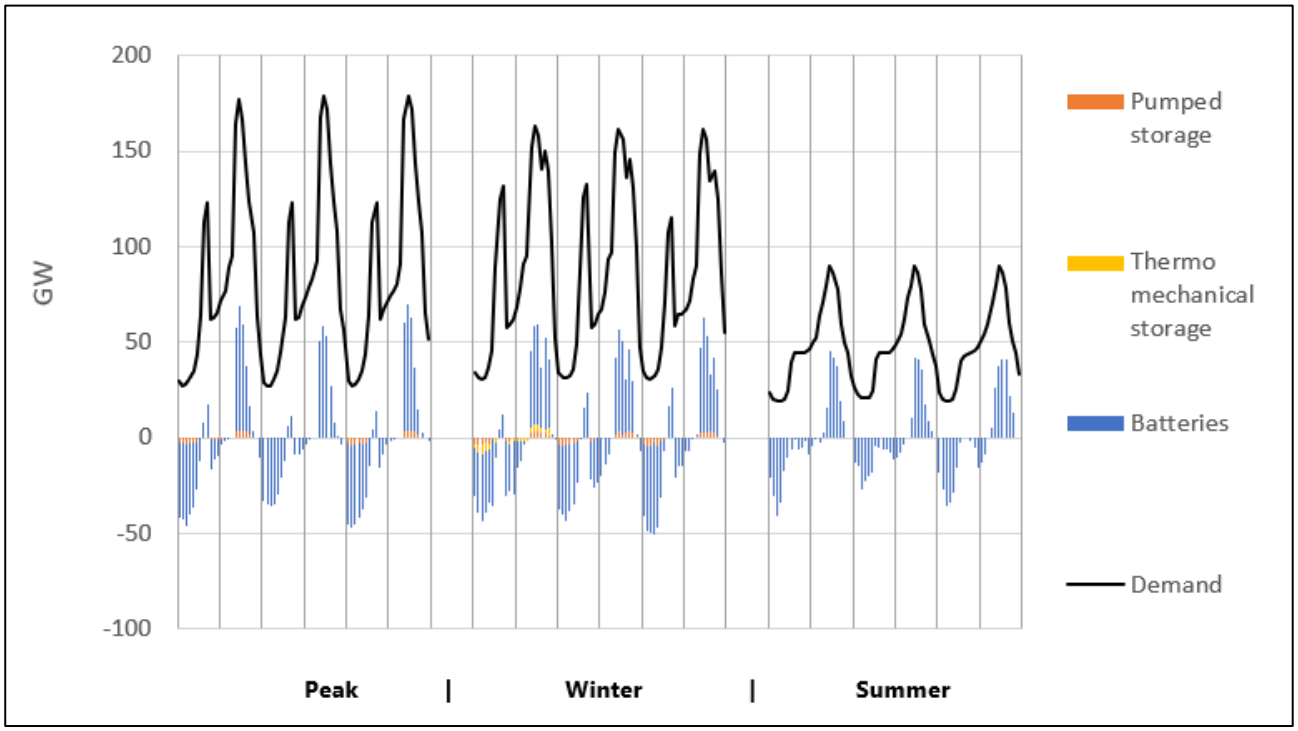

Figure 10: FA-SFM-UNF electrical storage dispatch (2050)[8]

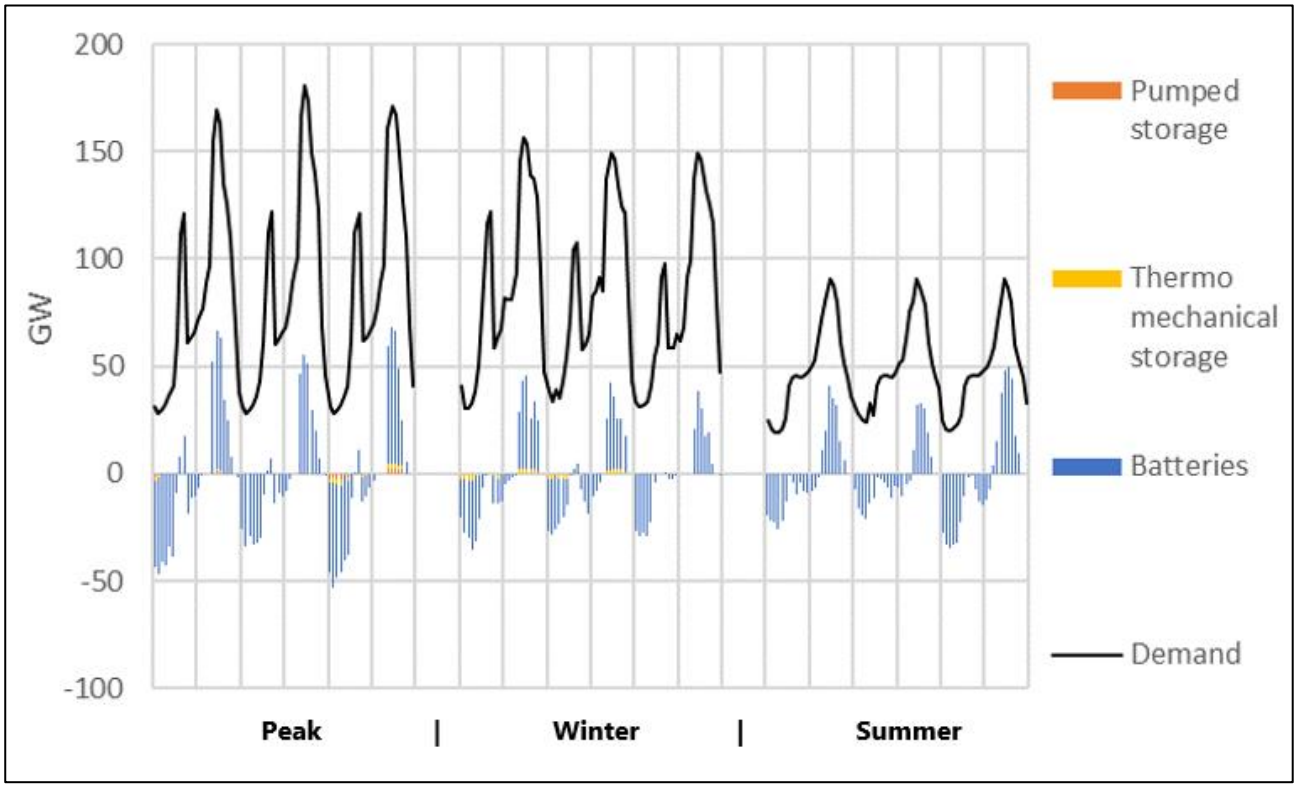

Figure 11: FA-SFM-125 electrical storage dispatch (2050)

[8] For these two figures 10 & 11 only, 72 hour periods (rather than 48 hour periods) are shown. 72 hours was required to show the full range of storage technologies dispatched during a given season. Each individual column represents 1 hour, with a vertical gridline every 12 hours.

4.5.3. Curtailment

When supply exceeds demand, and demand turn up (such as storage charging) is exhausted, renewable generation either needs to be stored, exported through an interconnector or curtailed. Figures 12 and 13 show the maximum electricity which could be produced from OSW according to hourly load factors, and compares it to the actual generation for FA-SFM-UNF and FA-SFM-125 respectively. The difference between maximum and actual generation reflects the capacity which is curtailed.

Under both scenarios there is almost no curtailment during the peak week due to the low level of OSW generation available and the high demand. During the winter, wind resource is high so there is curtailment during most periods except peak demand hours. During the summer wind resource is more variable and so curtailment tends to correspond to higher levels of wind generation. In general, curtailment is fluctuating in response to demand (given wind resource availability). However, it is likely that during times of lower demand net curtailment levels are reduced by interconnector exports, charging of storage and demand side response (i.e. charging EV's overnight).

The profile of curtailment across all three periods is similar for both scenarios and results in just over 30% of total OSW generation being curtailed in each, across a whole year including autumn and spring periods not shown. However, because there is significantly more OSW generation under FA-SFM-125, this corresponds to a greater level of total curtailed generation: ~190TWh/annum compared to 100TWh/annum under FA-SFM-UNF. As with the additional thermal capacity required, this may have commercial implications which need to be considered.

Section 4.6 includes a discussion on the possibility of using electrolysis to avoid curtailment. Workstream B has also explored this possibility. However, although both ESME and SFM models have options available to deploy hydrogen infrastructure and hydrogen demands in many ways, the results of Workstream A analysis show that there are cheaper ways of providing any back-up provision required – either by thermal generation or by producing hydrogen through other methods. Nevertheless, additional work is recommended in future to explore aspects of this further.

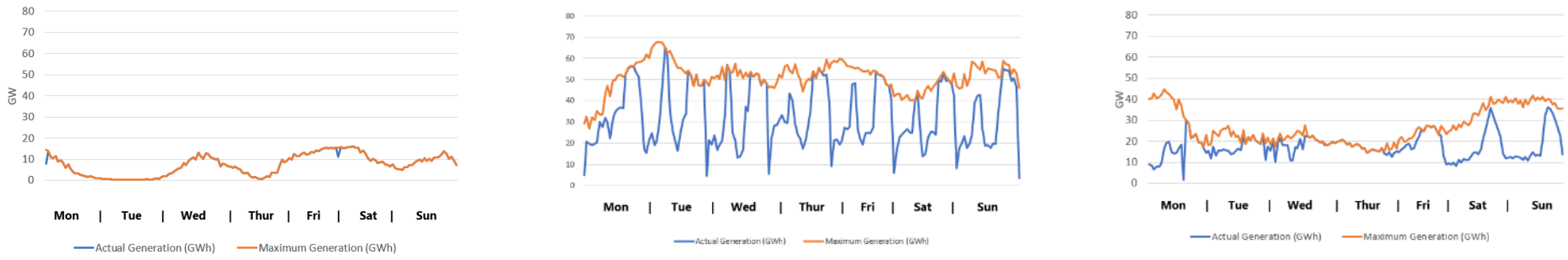

Figure 12: FA-SFM-UNF actual vs maximum available generation (2050) – peak (left), winter (centre), summer (right)[9]

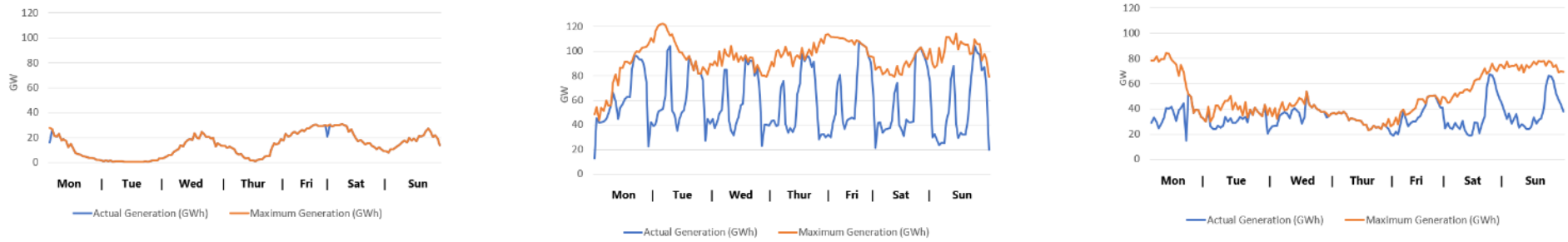

Figure 13: FA-SFM-125 actual vs maximum available generation (2050) – peak (left), winter (centre), summer (right)

[9] Except where stated otherwise, all dispatch charts show periods of 48 hours within each season, with each vertical gridline representing 12 hours.

4.5.4. System Services

Figure 14 shows the system service requirements for FA-SFM-UNF, and Figure 15 for FA-SFM-125. The formulae used to calculate them are provided in Appendix 1. However, to summarise:

- Frequency containment (primary frequency response) is the injection or withdrawal of power to maintain the frequency of the grid at 50Hz with very short response times (within 10s) to be sustained for up to 20 seconds.
- Frequency replacement (secondary frequency response) is the injection or withdrawal of power within 30 seconds to be sustained for up to 30 minutes.
- Reserve replacement is the injection of power for longer durations to balance forecast errors and power outages. Minimum response time is several minutes with a minimum duration of several hours.
- Headroom is the injection of power (or withdrawal of demand), required when demand outstrips supply.
- Historically footroom (withdrawal of power/injection of demand) has been easy to provide as load-following fossil fuel plants could just be turned down. With the increasing deployment of renewable generation this has now changed, although the SFM currently isn't capable of representing it. Work is ongoing to add this capability to future iterations of the model.

In both scenarios frequency containment and frequency replacement reduce from 2030 to 2050. This initially appears to be counterintuitive, as the significant increase in renewable generation reduces system inertia and so increases the need for these services. However, from 2030 to 2050 there is a significant increase in demand (see Figures 4 and 5) which counteracts the lack of inertia. The slightly lower levels under FA-SFM-UNF are likely to be in part due to the higher nuclear capacity which provides higher levels of inertia.

In both scenarios reserve replacement increases significantly by 2050, with a maximum reserve requirement of 28GW under FA-SFM-UNF and 34GW under FA-SFM-125. Reserve replacement is required to cover unforeseen plant shortages and renewable forecast error; therefore the higher deployment of OSW in FA-SFM-125 leads to the greater increase in need for reserve replacement.

Winter has the greatest requirement for reserve replacement under both scenarios as it has the highest levels of renewable dispatch. This highlights the value of continual improvements in forecasting, while a shortening of market timescales as discussed in Task 4 will also reduce forecast error. This also highlights that the calculation of system services is based on current arrangements, which may change as processes improve and/or the energy system develops. Future modelling analysis should account for these developments.

Figures 16 and 17 show the contribution that technologies make to providing headroom for all system services under FA-SFM-UNF and FA-SFM-125 in 2030 and 2050. In both scenarios thermal generation with support from batteries provide the bulk of system services. Thermo mechanical and pumped storage make small but reasonable contributions in 2030. By 2050 the high levels of thermal generation required on the system for the peak week result in little need for storage technologies to provide system services. The exception is batteries which contribute most in the peak week when much thermal generation is committed to providing bulk energy supply.

When calculating technology contributions to system services, SFM holds technologies in the required state to provide these short term services if required, rather than modelling the *utilisation* actions of technologies against, in the case of frequency response, these very short-term services.

This approach is taken to reduce the computational effort required to model these services. However, when modelling Net Zero systems this does result in a limitation that, because these technologies are only held and not utilised, their carbon emissions are not accounted for. System services are only used for short periods of time, and often with small capacities, so any emissions produced are likely to be small but it should nevertheless be recognised.

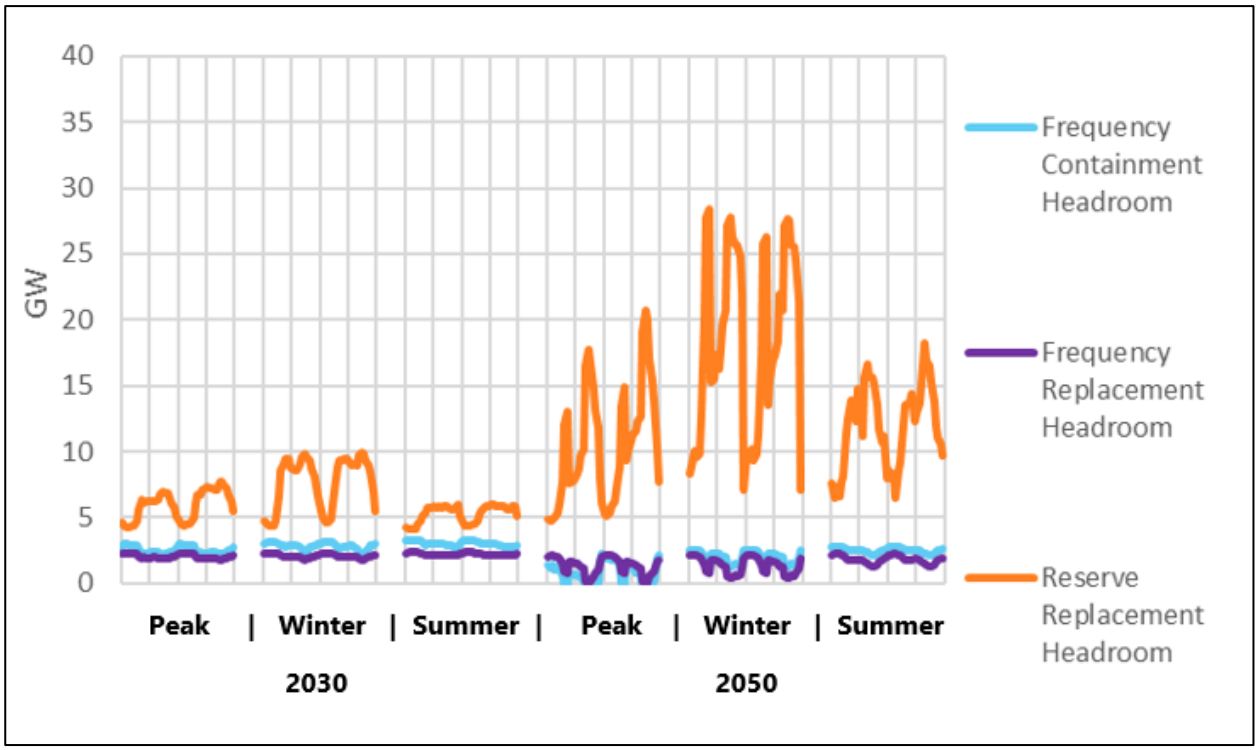

Figure 14: FA-SFM-UNF system service requirements

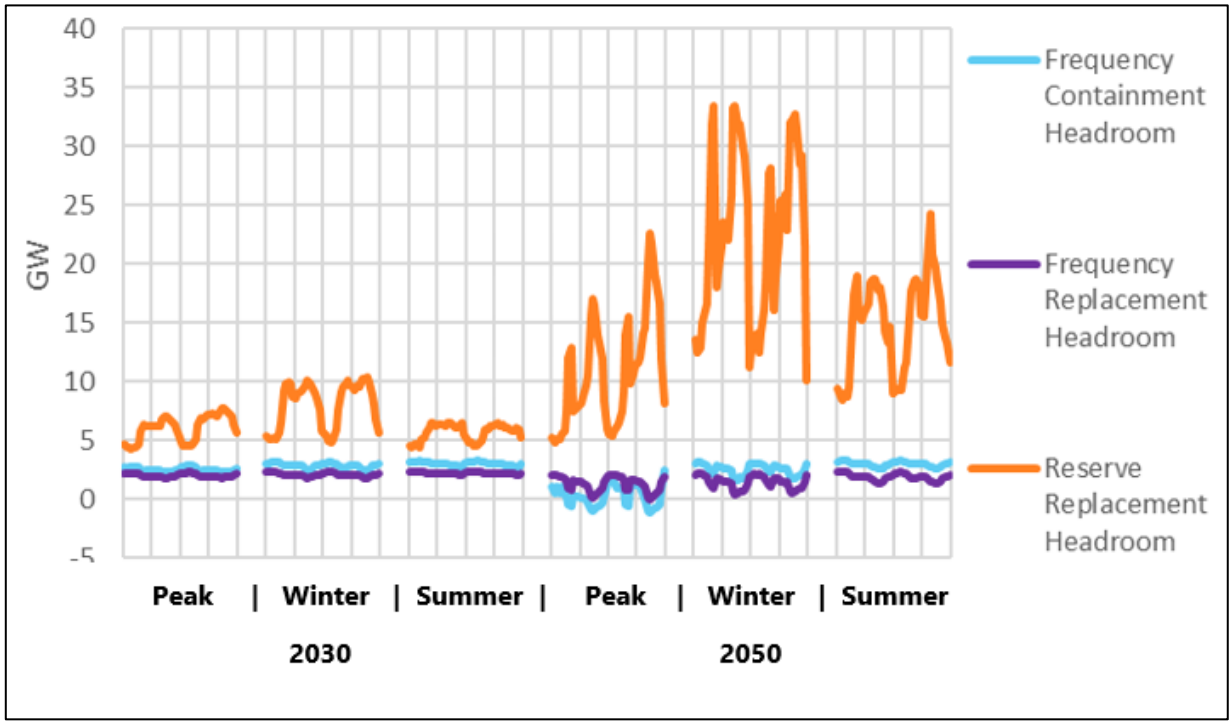

Figure 15: FA-SFM-125 system service requirements

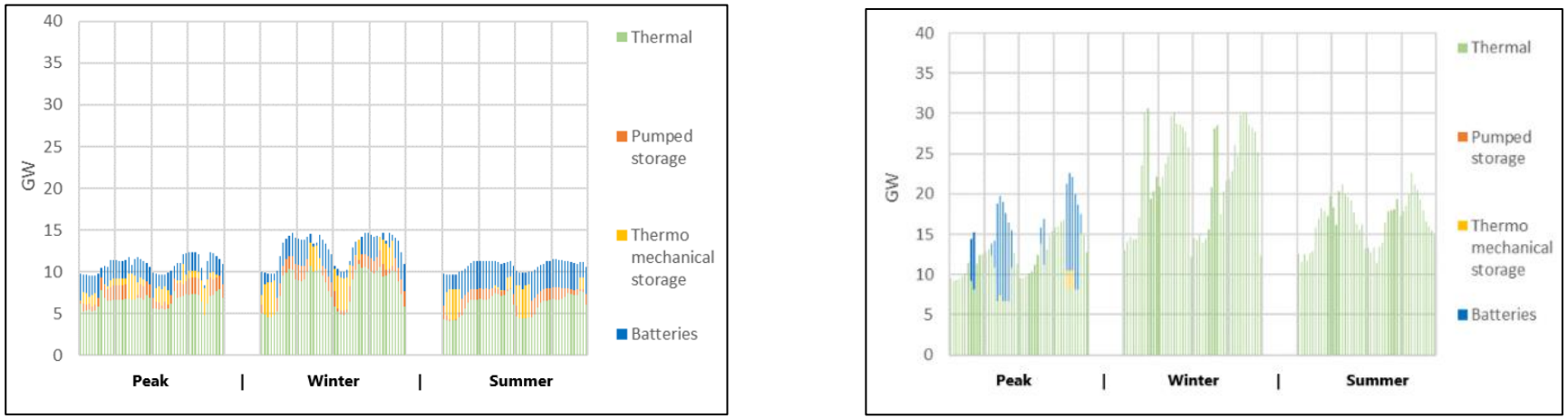

Figure 16: FA-SFM-UNF headroom contributions – 2030 (left) and 2050 (right)

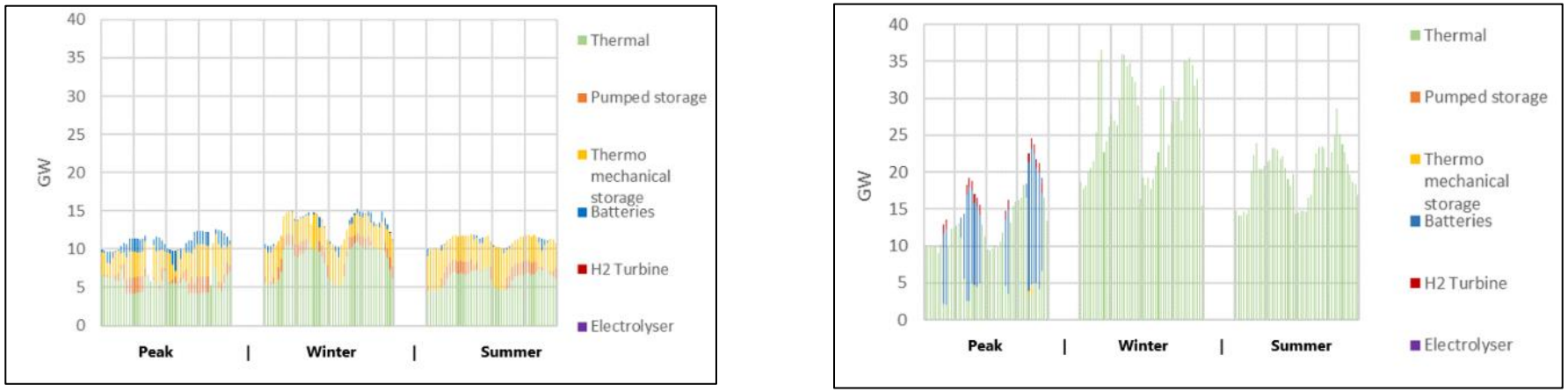

Figure 17: FA-SFM-125 headroom contributions – 2030 (left) and 2050 (right)

4.6. Results – Hydrogen and Natural Gas Production and Consumption

Key results:

- Under both scenarios natural gas production falls between 2030 and 2050, from 585TWh/annum to 90TWh/annum under FA-SFM-UNF and from 600TWh/annum to 186TWh/annum under FA-SFM-125. Production is higher under FA-SFM-125 due to the greater reliance on Steam Methane Reformation with CCS to produce hydrogen.
- Under both scenarios, as emissions constraints tighten, hydrogen production rises between 2030 and 2050, from 46TWh/annum to 227TWh/annum under FA-SFM-UNF and from 49TWh/annum to 234TWh/annum under FA-SFM-125.
- Natural gas storage decreases between 2030 and 2050 under FA-SFM-UNF, to around 400GWh by 2050. Natural gas storage increases under FA-SFM-125 between 2030 and 2050, to a total of 900GWh, due to increased thermal generation for rare low-wind weeks, and the use of Steam Methane Reformation with CCS to produce hydrogen. However, this is still small compared to current natural gas storage levels of ~27,000GWh[10].
- Long range natural gas storage, which makes up the vast majority of natural gas storage, follows a seasonal charging cycle which levels production seasonally and increases utilisation rates of gas production technologies.
- Natural gas linepack provides short term flexibility over peak periods only (shifting demand from morning and evening peaks to midday and overnight periods). In seasons where the system is less stressed (e.g. summer), the short-term flexibility available from long-range storage is sufficient to balance supply and demand, and linepack is not used.
- No seasonal hydrogen storage is used in either scenario. The variation in demand for hydrogen is relatively small and can be managed without the need for seasonal storage. There is still the need for hydrogen storage, in the form of linepack, to help meet the daily swings; 68GW and 75GW of hydrogen linepack are deployed by 2050 in FA-SFM-UNF and FA-SFM-125 respectively.

Figures 18 and 19 show the hydrogen and natural gas production for FA-SFM-UNF and FA-SFM-125 respectively for 2030 and 2050.

Due to the Net Zero emissions constraint, natural gas production drops (FA-SFM-UNF: 585TWh to 90TWh, FA-SFM-125: 600TWh to 186TWh) and hydrogen production increases (FA-SFM-UNF: 46TWh to 227TWh, FA-SFM-125: 49TWh to 234TWh). In 2030 the production methods are broadly similar between scenarios; however, by 2050 there is some variation, including almost twice the amount of natural gas imports under FA-SFM-125, most of which are used in the production of hydrogen through steam methane reformation with CCS (SMR CCS).

[10] IEA Experts' Group on R&D Priority Setting and Evaluation. 2019. https://iea.blob.core.windows.net/assets/imports/events/117/15_wilson_EGRD_Vienna2019_Grant_Wilson.pdf

In respect of hydrogen, although total production is very similar, FA-SFM-125 is more dependent on steam methane reformation with CCS, while FA-SFM-UNF utilises more electrolysis and coal gasification.

The trend in the UK is to move away from coal, and consequently coal gasification is generally not viewed favourably in the UK. However, previous internal studies undertaken by the ETI into the marginal cost difference of coal gasification and SMR have shown that they can broadly be seen as fulfilling very similar roles. Therefore if coal gasification was removed it would likely be replaced with SMR CCS. The key decision that the model makes between SMR CCS and coal gasification is the cost vs emissions trade-off. Coal gasification is cheaper but produces more emissions and so is only favoured when carbon targets are being met.

Under FA-SFM-125 there is 3GW of oil boiler capacity remaining in the system, partly to help reduce demand on the electricity network which is more stressed under FA-SFM-125 since the system is more vulnerable to any short term reduction in wind availability.

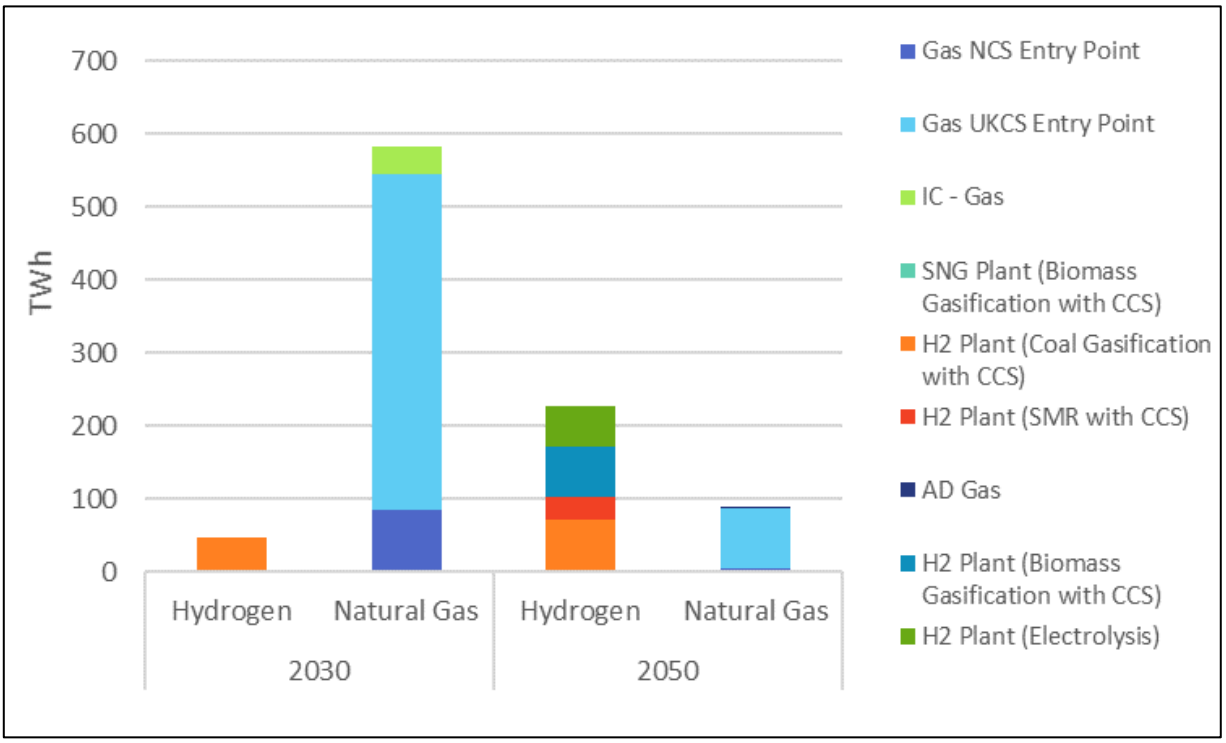

Figure 18: FA-SFM-UNF hydrogen and natural gas production

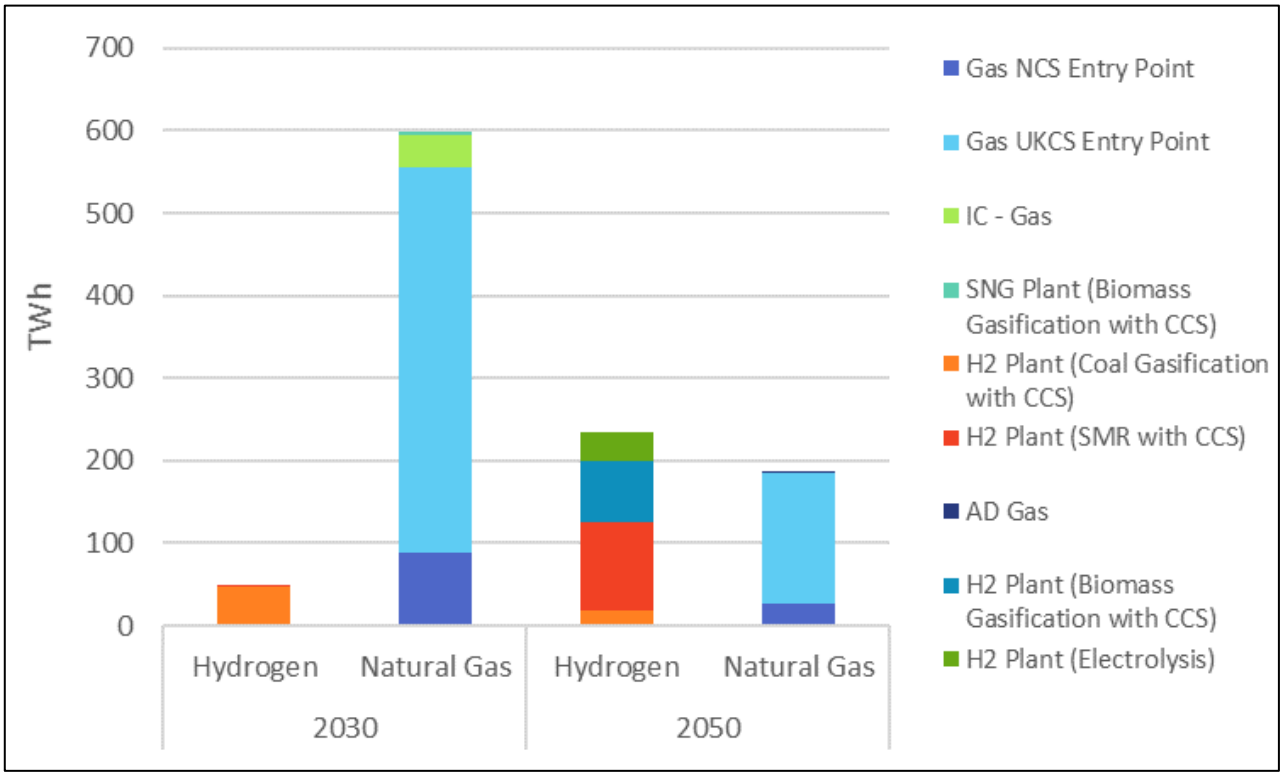

Figure 19: FA-SFM-125 hydrogen and natural gas production

Figures 20 and 21 show how hydrogen and natural gas are consumed for FA-SFM-UNF and FA-SFM-125 respectively. In 2030, hydrogen and natural gas consumption are similar across scenarios with gas boilers consuming the greatest levels of natural gas (FA-SFM-UNF: 270TWh, FA-SFM-125: 312TWh).

By 2050, gas boiler usage has been removed under both scenarios, whilst the additional natural gas consumption of FA-SFM-125 is due to the use of SMR CCS to produce hydrogen as identified above. Otherwise, natural gas and hydrogen consumption are similar across scenarios, with natural gas only being used for those areas with residual emissions that are difficult to remove – i.e. industry and maritime.

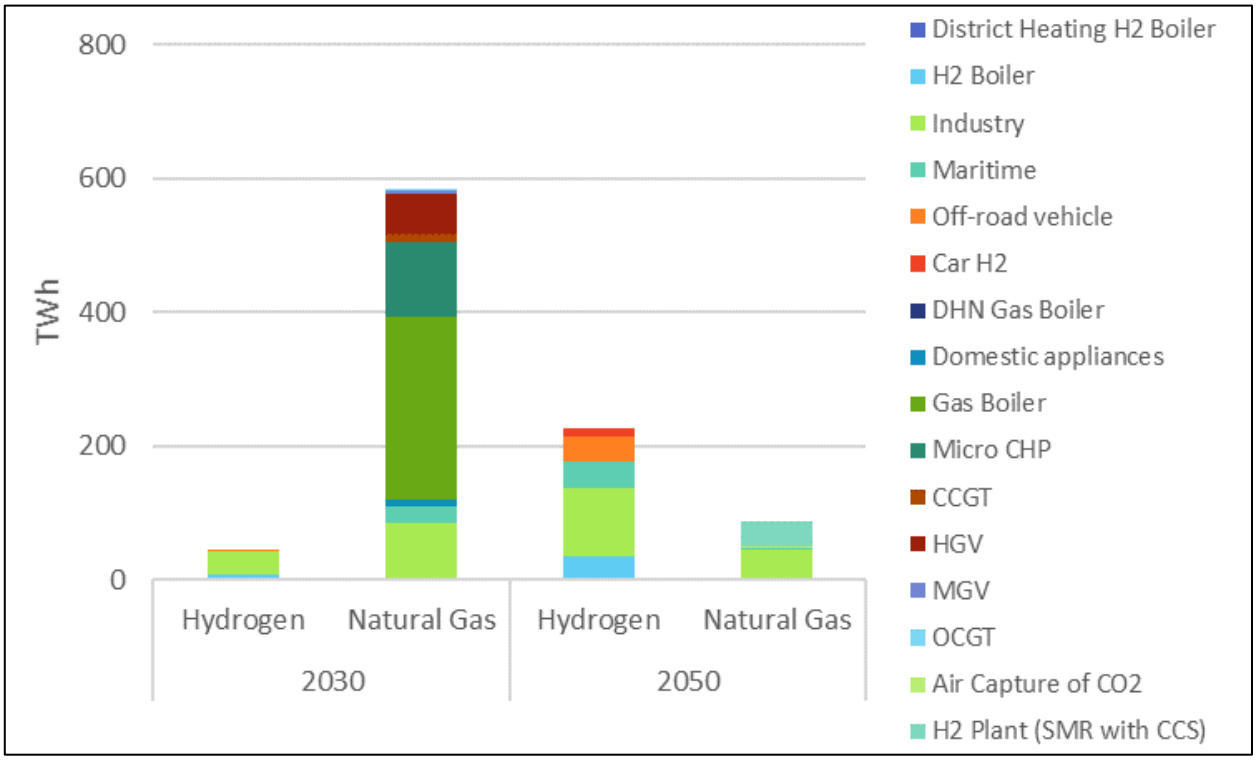

Figure 20: FA-SFM-UNF hydrogen and natural gas consumption

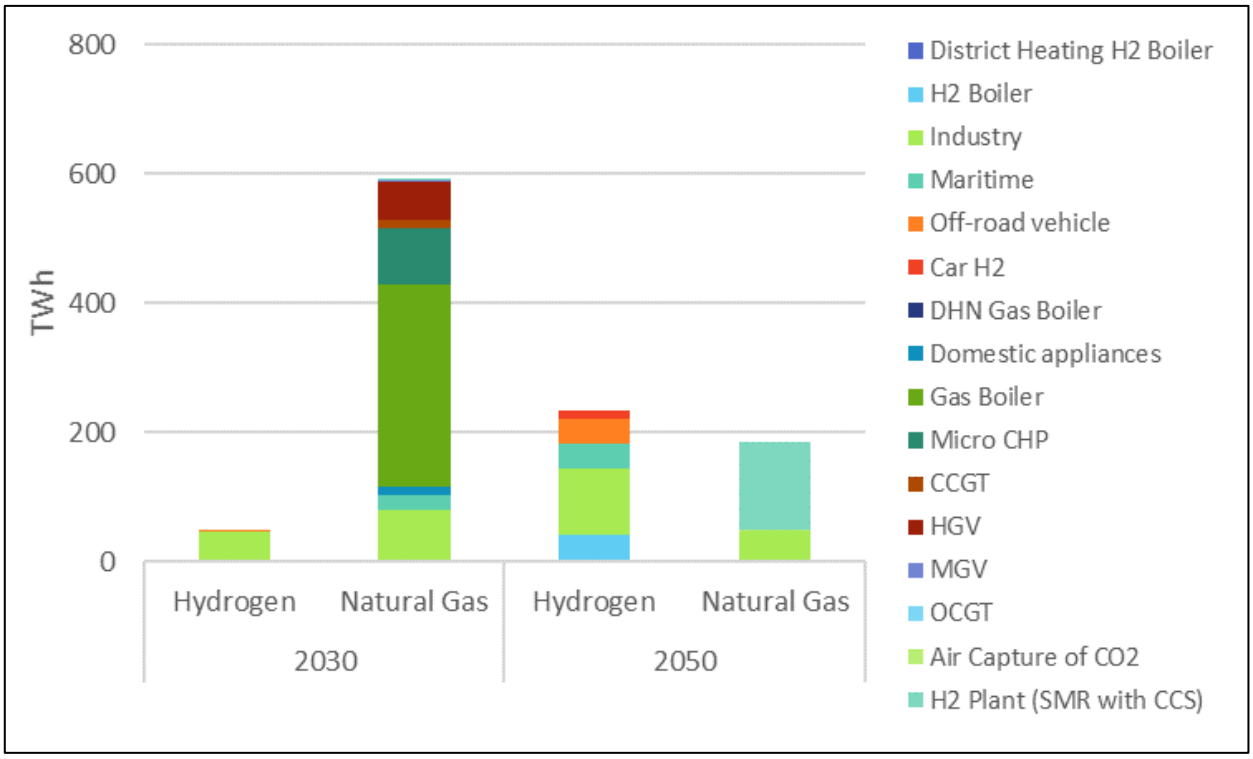

Figure 21: FA-SFM-125 hydrogen and natural gas consumption

4.6.1. Hydrogen and Natural Gas Production Dispatch

Figures 22 and 23 overleaf show the hydrogen and natural gas dispatch in 2050 for FA-SFM-UNF and FA-SFM-125. Total maximum dispatch is relatively similar between scenarios and occurs during the peak season, as this season experiences the highest demand for heat and gas-based electricity production. The summer season is much less 'peaky' than the other two periods because heat demand is relatively small – which means that hydrogen and natural gas are required less for meeting peak demands within both boilers and power plants; with most electricity demand balancing being met by renewables and electricity storage (see Figures 4, 5, 10 and 11).

It should also be noted that dispatch is less peaky in 2050 compared to 2030, this can be explained by Figures 20 and 21 above. In 2030 significant natural gas is consumed for heating which typically has large daily swings in demand. By 2050, as the heat sector electrifies, the majority of natural gas consumption is for applications with more constant demand such as industry.

It is also noted that, although Figures 18 and 19 include production of hydrogen from electrolysis (FA-SFM-UNF: 55TWh/annum, FA-SFM-125: 35TWh/annum), Figures 22 and 23 do not show any electrolysers being dispatched. The reason for this relates to the structure of SFM. To keep the model tractable it is actually two individual modules – the Long Term Module (LTM) which is responsible for long term capacity building, and the Short Term Module (STM) which dispatches this capacity (see section 1.1). The two modules feed information to each other through a series of iterations, and this iterative process is designed to create an equilibrium between the two modules.

However, there are rare instances when the assumptions used can lead to a difference between the two modules, this is not an error but rather can provide useful insights. In this instance the LTM produces some hydrogen from electrolysis because under the electricity mix in the scenarios tested it results in zero carbon hydrogen, which is required to meet demand and keep emissions low. However, the whole system operational costs of electrolysis are higher than those of fossil fuel gasification and SMR with CCS, and there is insufficient market signal to deploy electrolysis when lower marginal cost hydrogen production options are available.

Curtailment payments for OSW are considered to be a policy-based decision and so are not included in SFM; however, the cost saving of avoiding these could support the case for dispatching more electrolysis. Alternatively, excess electricity may also be exported via interconnector.

Taken as a whole, this results in the STM, which optimises by operational and resource cost, declining to dispatch the electrolysers.

This suggests that whilst under the FA scenarios tested electrolysis is essential to meet Net Zero targets, and so is selected to some extent by the LTM, further innovation and deployment is needed to lower the operational whole system costs of electrolysis. SFM is policy neutral, and there may be policy-based decisions which do not support coal gasification or Steam Methane Reformation, resulting in greater deployment of electrolysis which in turn would further drive the need to lower electrolysis costs.

The ability of electrolysis to produce zero-carbon hydrogen (recognised by SFM) makes it likely to be a key technology in meeting net zero targets, especially in the absence of high-capture-rate CCS. If the costs of green hydrogen (including total operational costs of the electrolysis and electricity generation) were considerably lower than the cost reduction curves already assumed in the modelling, then the whole system costs would be somewhat reduced – although the results are not strongly sensitive to electrolysis pricing, largely because of the system-wide implications of driving in more electricity generation). There is then potential for higher levels of deployment than

modelled. Task 5 discusses in more detail the need for innovation to reduce electrolysis costs. There is, of course, still competition in hydrogen production, with likely further innovation in blue hydrogen technologies.

Finally, it should be noted that, where there are differences in conclusions between the modelling undertaken in this Workstream A and that in Workstream B (such as choices between green and blude hydrogen), these differences are deliberate and are intended to be read as complementary perspectives. Workstream B has taken a perspective on the possibilities for hydrogen and electrolysis in particular, with certain modelling assumptions, whereas Workstream A has taken a more holistic system perspective (for example, electrification of demand as a lower whole-system cost than greater deployment of electrolysis), leading in some respects to more nuanced and complex conclusions. The reports from both Workstreams should be read together in order to understand the results informed by both sets of perspectives.

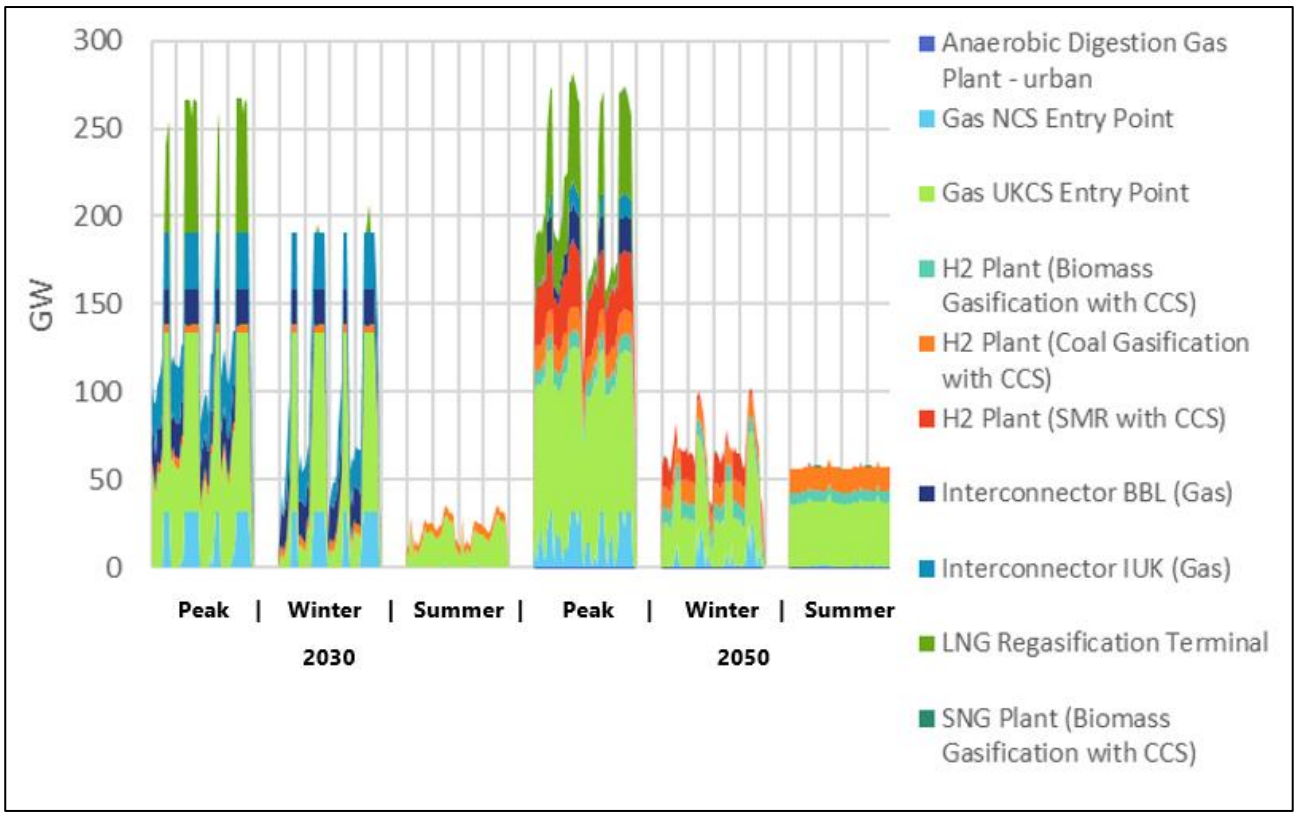

Figure 22: FA-SFM-UNF 2050 hydrogen and natural gas dispatch[11]

[11] Except where stated otherwise, all dispatch charts show periods of 48 hours within each season, with each vertical gridline representing 12 hours.

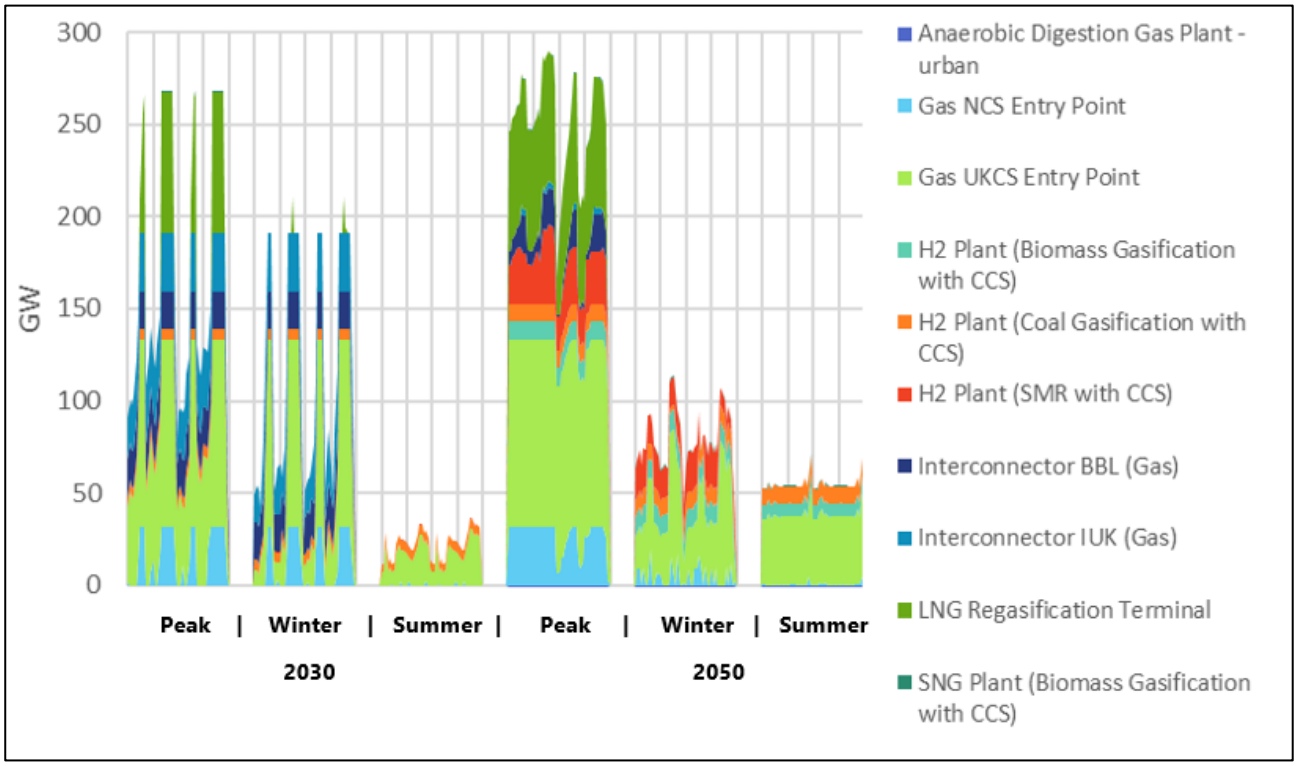

Figure 23: FA-SFM-125 2050 hydrogen and natural gas dispatch

4.6.2. Natural Gas and Hydrogen Storage

Figures 24 and 25 show the natural gas and hydrogen storage volume for FA-SFM-UNF and FA-SFM-125 respectively.

Total natural gas storage decreases between 2030 and 2050 under FA-SFM-UNF, which coincides with the reduction in natural gas consumption. Under FA-SFM-125, seasonal natural gas storage increases between 2030 and 2050, to just over 900GWh. However this is still small compared to the current level of ~27,000GWh[10] and reflects the reduction in natural gas consumption.

It can be seen that seasonal natural gas storage is used mostly during the peak week. Referring to Figure 5, there is a higher reliance on CCGT, OCGT and micro CHP during the peak week under FA-SFM-125 which leads to an increased demand for natural gas and increased need for natural gas storage compared to FA-SFM-UNF. During the winter week, the increased demand from SMR CCS is also partly responsible for the increased natural gas demand. The increased use of CCGT, OCGT and micro CHP during winter and peak week for system services may also contribute to the increase in natural gas demand, although this will be a relatively small contribution.

This increase in winter and peak natural gas demand leads to long-range natural gas storage following a seasonal charging cycle which levels out production seasonally and increases utilisation rates of natural gas production technologies. Natural gas linepack provides short term flexibility over peak periods only (shifting demand from morning and evening peaks to midday and overnight periods). In seasons where the system is less stressed (e.g. summer), the flexibility available from long-range storage is sufficient to balance supply and demand, and linepack is not used.

No seasonal hydrogen storage is used, although it is available as a technology option. Referring back to Figures 22 and 23, the variation in demand for hydrogen is relatively small, as the majority

of hydrogen is used for industry, shipping and off-road vehicles. The difference in maximum dispatch between the peak and summer weeks is 46GW and 42GW for FA-SFM-UNF and FA-SFM-125 respectively; (as a comparison it is 225GW and 180GW for natural gas). This is a much smaller variation and can be managed without the need for seasonal storage. If deployment of electrolysis was higher than modelled, perhaps for the reasons discussed in Section 4.6.1, then this may lead to an increased need for seasonal storage. However, for high deployments of seasonal hydrogen storage to occur it is likely that costs would have to reduce enough for hydrogen to displace electrification for significant levels of heating demand.

Therefore, further work is recommended to quantify the potential value of seasonal hydrogen storage (a) in the event that green hydrogen became available at costs considerably lower than the cost reduction curves already assumed in the modelling and (b) for the avoidance of curtailment payments (if such payments remained part of a future market structure) .

Despite this lack of need for seasonal storage, there is still the need for hydrogen storage in the form of linepack to help meet the daily swings highlighted in Figures 22 and 23, driven largely by hydrogen boilers. 68GWh and 75GWh of hydrogen linepack are deployed by 2050 in FA-SFM-UNF and FA-SFM-125 respectively.

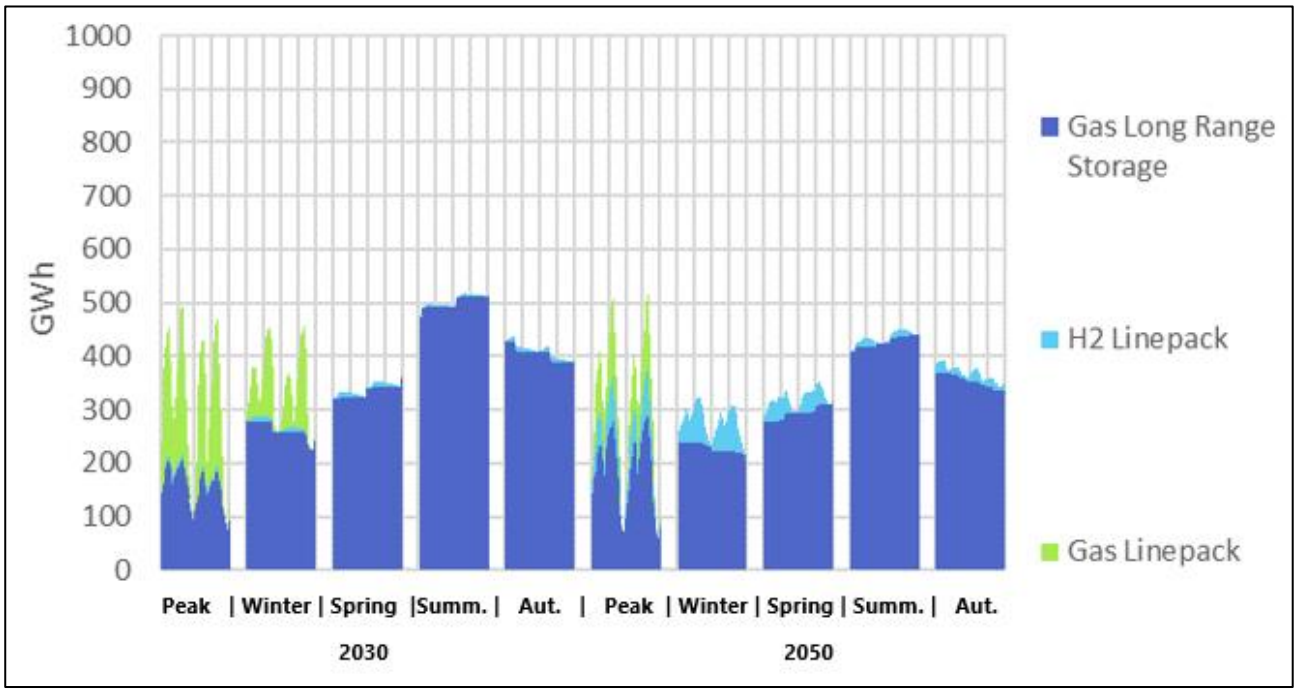

Figure 24: FA-SFM-UNF natural gas and hydrogen storage volume

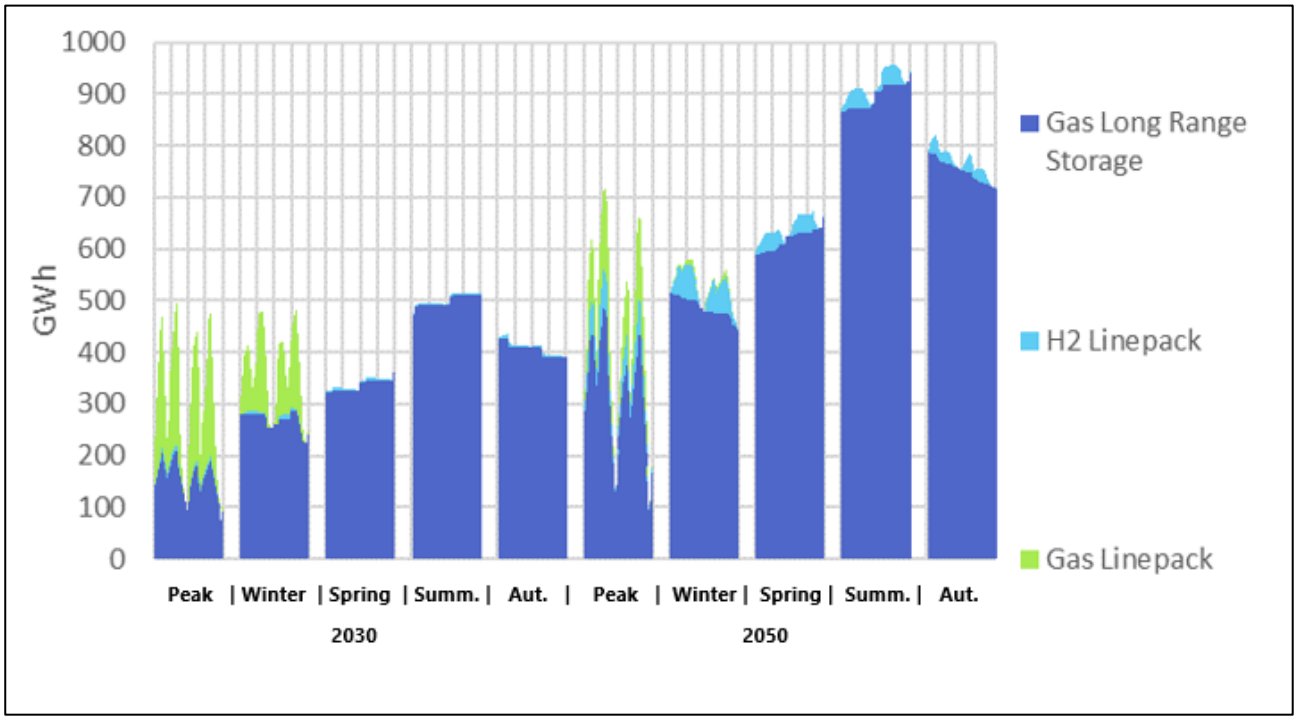

Figure 25: FA-SFM-125 natural gas and hydrogen storage volume

4.7. Results – Space Heat

Key results:

- Over 90% electrification of the heat sector is seen by 2050 under both scenarios.
- Building level thermal storage is similar between scenarios and increases significantly by 2050 to 276GW/552GWh for FA-SFM-UNF and 273GW/546GWh for FA-SFM-125.
- This increase in thermal storage is due to its role in smoothing electrified heat production and avoiding coupling of the electricity sector to high intra-day heat demand variation.

Figures 26 and 27 show the annual heat supply for FA-SFM-UNF and FA-SFM-125 respectively for 2030 and 2050. Under both scenarios heat supply increases slightly to meet increased demand from 2030 to 2050. While there is some limited scope for heat demand reductions (through building retro-fit options), this is offset by population and GDP-related growth.

Heat supply technologies are largely the same between scenarios. By 2050 the heat sector has undergone significant electrification with approximately 90% (396TWh) being provided by electric sources (air source, ground source and large scale marine heat pumps, plus resistive heating), with similar figures for both FA-SFM-UNF and FA-SFM-125. This electrification significantly increases electricity demand over the peak periods, especially during the peak and winter weeks.

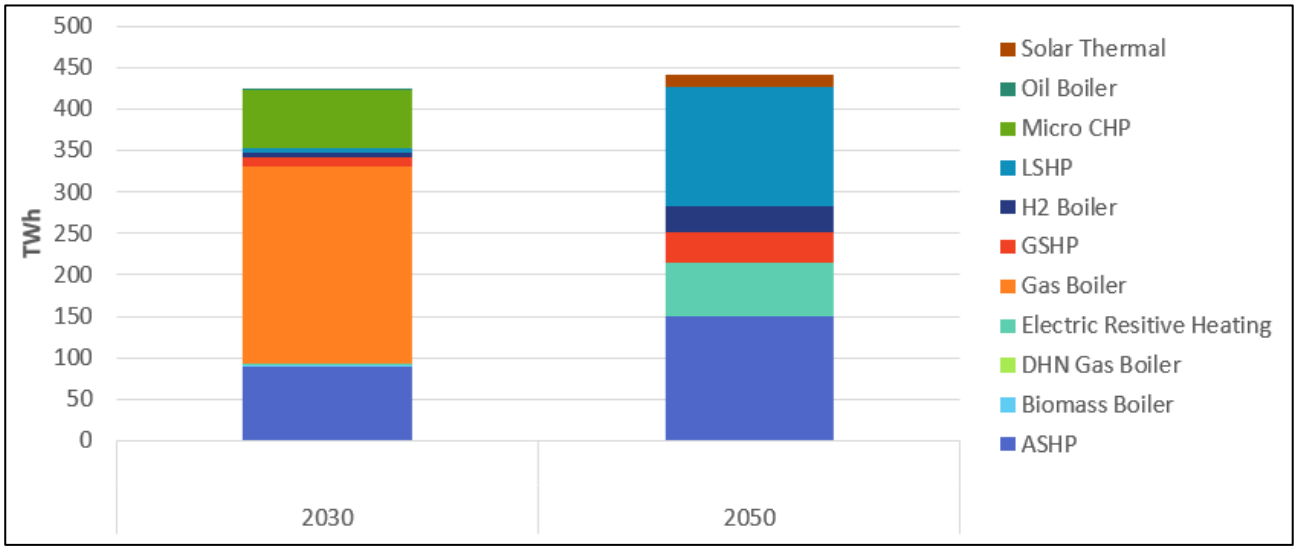

Figure 26: FA-SFM-UNF annual heat supply

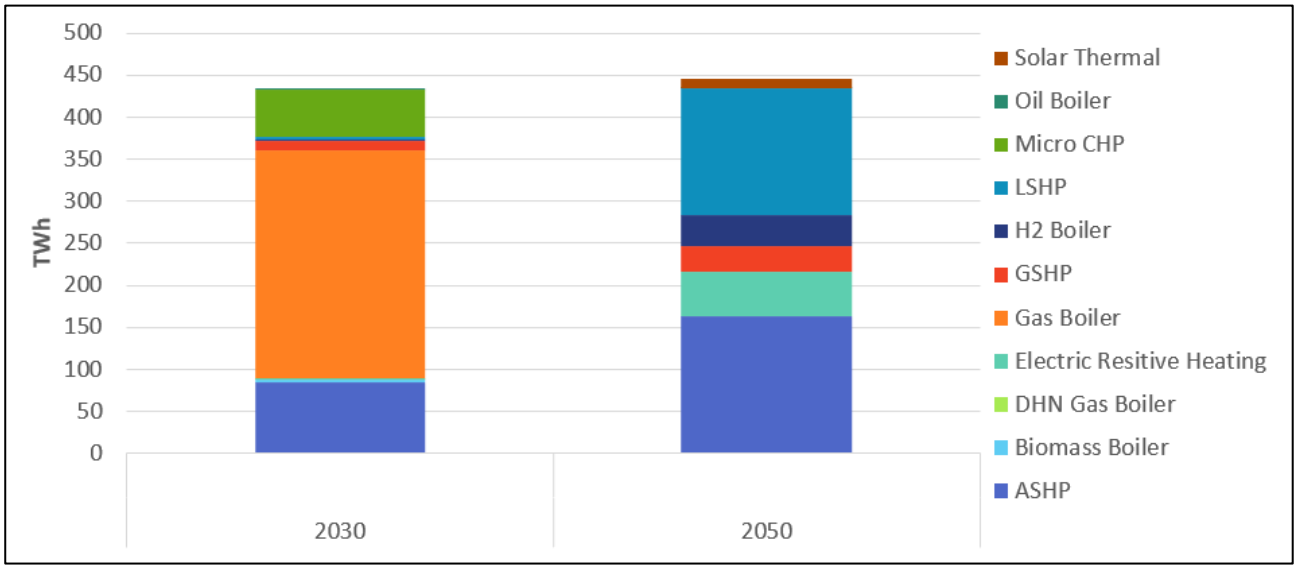

Figure 27: FA-SFM-125 annual heat supply

4.7.1. Dispatch

Figures 28 and 29 show the heat dispatch respectively for the two scenarios in 2030 and 2050. In both scenarios ASHPs run at close to baseload operation (at least during winter and peak seasons), despite the highly variable shape of heat demand. It is building-level heat storage, alongside complimentary technologies such as electric resistive heating running within hybrid systems, that allows ASHPs to run in this way. The building-level heat storage soaks up heat in periods of low heat demand and supplies it again in high demand periods, which increases the load factor (and therefore lowers the LCoE) of ASHPs.

Other technologies have to ramp up and down to meet large daily variations in demand, especially in winter and peak weeks. Even with this ramping, dispatch still fails to meet demand during the morning and evening peaks over the winter and peak weeks. This results in the need for substantial levels of thermal storage (primarily hot water tanks). This storage is charged both overnight and during the day between peaks (when dispatch is greater than demand).

Note that there are some constraints caused by the physical size of domestic thermal storage technologies (primarily hot water tanks), which may limit the properties into which they can be deployed; however, these are taken into account in the modelling above. This is discussed further in section 4.7.2 and in Task 5 (Innovation Requirements).

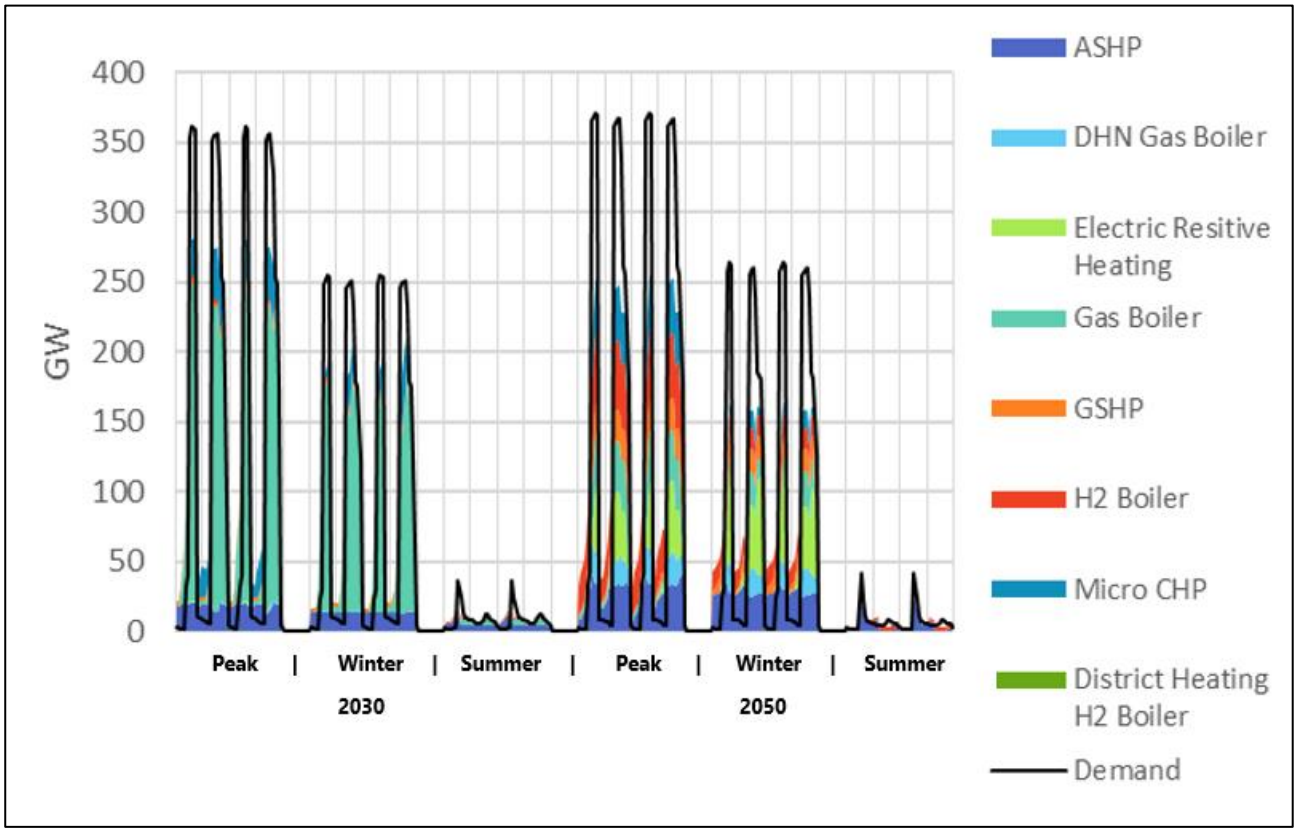

Figure 28: FA-SFM-UNF heat dispatch[12]

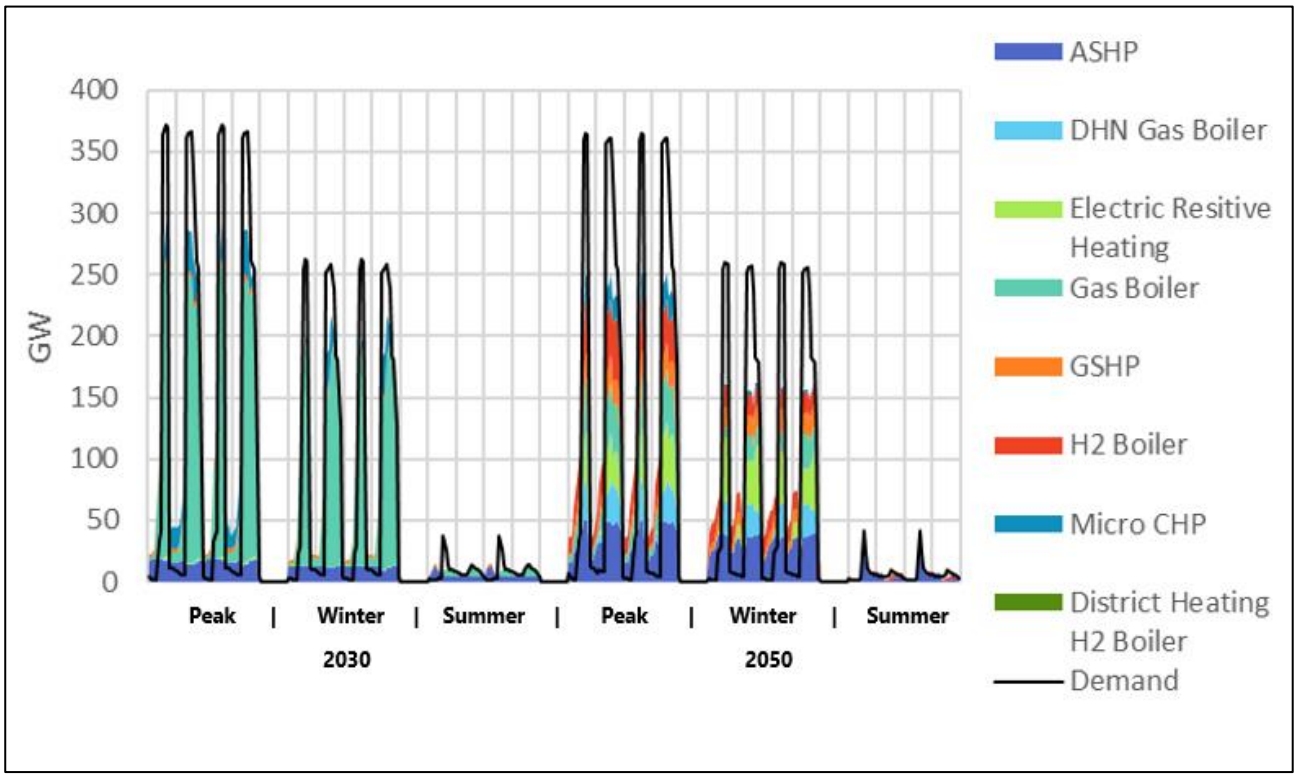

Figure 29: FA-SFM-125GW heat dispatch

[12] Note LSHP's have a similar occurrence in the STM as electrolysis, LSHP's will have less of a direct effect on OSW and flexibility and therefore is not focused on in this report.

4.7.2. Thermal Storage

Figures 30 and 31 show the thermal storage power rating and capacity respectively for both scenarios. The balance of technologies is broadly the same between FA-SFM-UNF and FA-SFM-125, with an increase of 239GWh and 228GWh between 2030 and 2050 respectively. This is driven by the high electrification of the heat sector.

The high variability of output of gas boilers in peak periods (see Figures 28 and 29) 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. However, fluctuations in the electricity network due to electrified heat technologies are far more challenging to manage, particularly in this case with such large levels of electrification. Thermal storage is used, for example by running heat pumps in baseload operation, to smooth electrified heat production and avoid coupling the electricity sector to high intra-day heat demand variation.

Although similar, FA-SFM-UNF has a slightly higher level of total thermal storage at 276GW/552GWh, compared to FA-SFM-125 at 273GW/546GWh. In a similar trend to electricity storage, although the additional wind in FA-SFM-125 is inflexible and cannot follow demand, the higher deployment of nuclear generation that replaces much of the additional wind capacity in FA-SFM-UNF is also inflexible and also requires substantial levels of thermal storage.

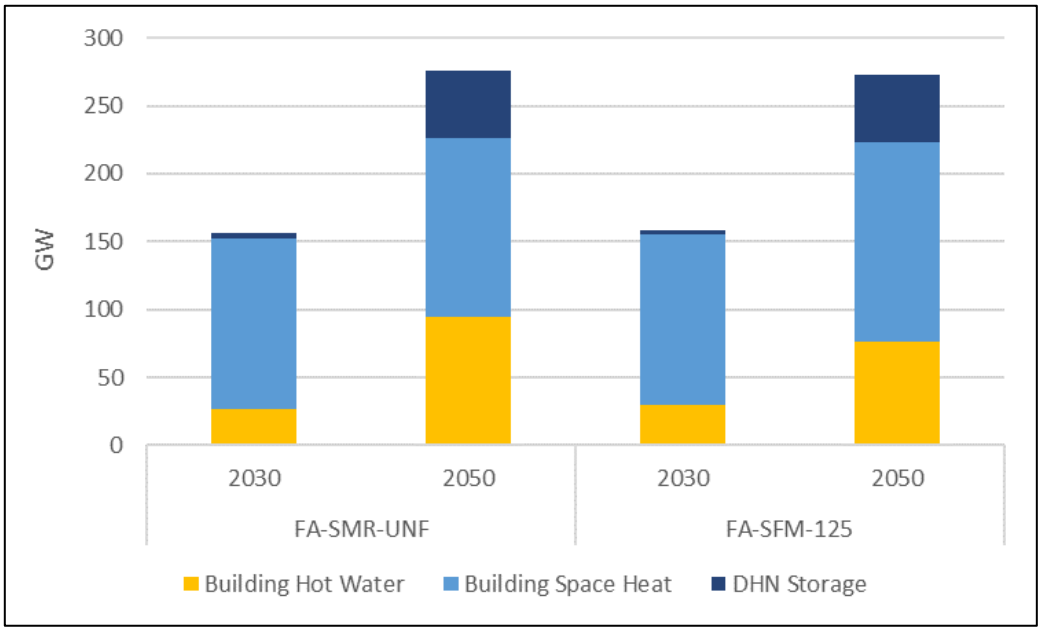

Figure 30: Thermal storage power rating, both scenarios

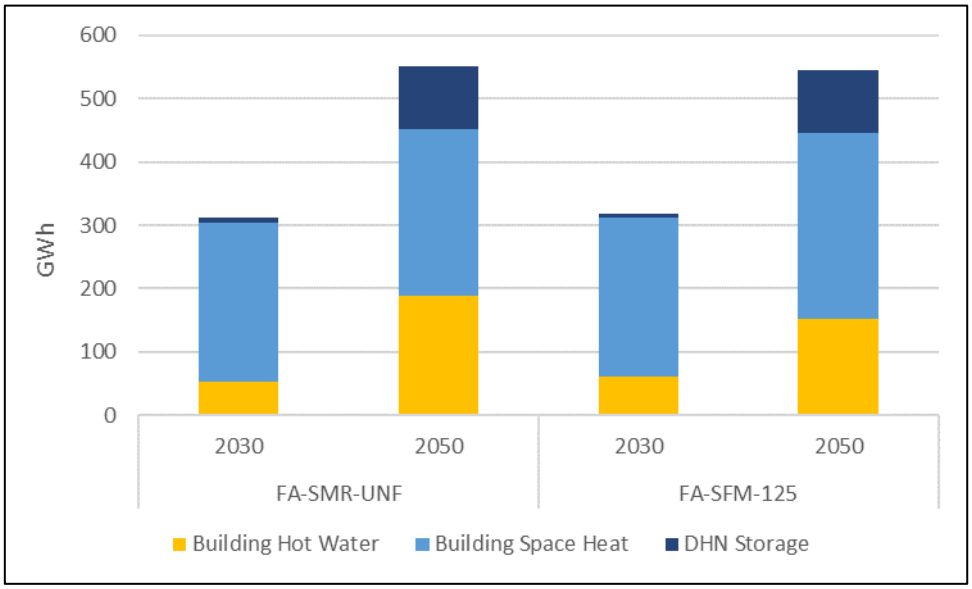

Figure 31: Thermal storage capacity, both scenarios

Figures 32 and 33 show the thermal storage dispatch for each scenario. During the peak and winter weeks these technologies are being used close to their full storage volume – fully charging and discharging on at least daily basis to meet daily cycles in heat demand. As suggested in section 4.7.1, storage is being charged during times of low demand (i.e. overnight and mid-day) to be discharged during the morning and evening peaks.

SFM could choose to use heat storage to shift energy from one day to another. However, this mode is not favoured – due to the relatively high losses incurred when storing heat, and to the constraints on the size of storage tank that can be fitted per building (limiting the volume of the storage technology, compared with its output capacity).

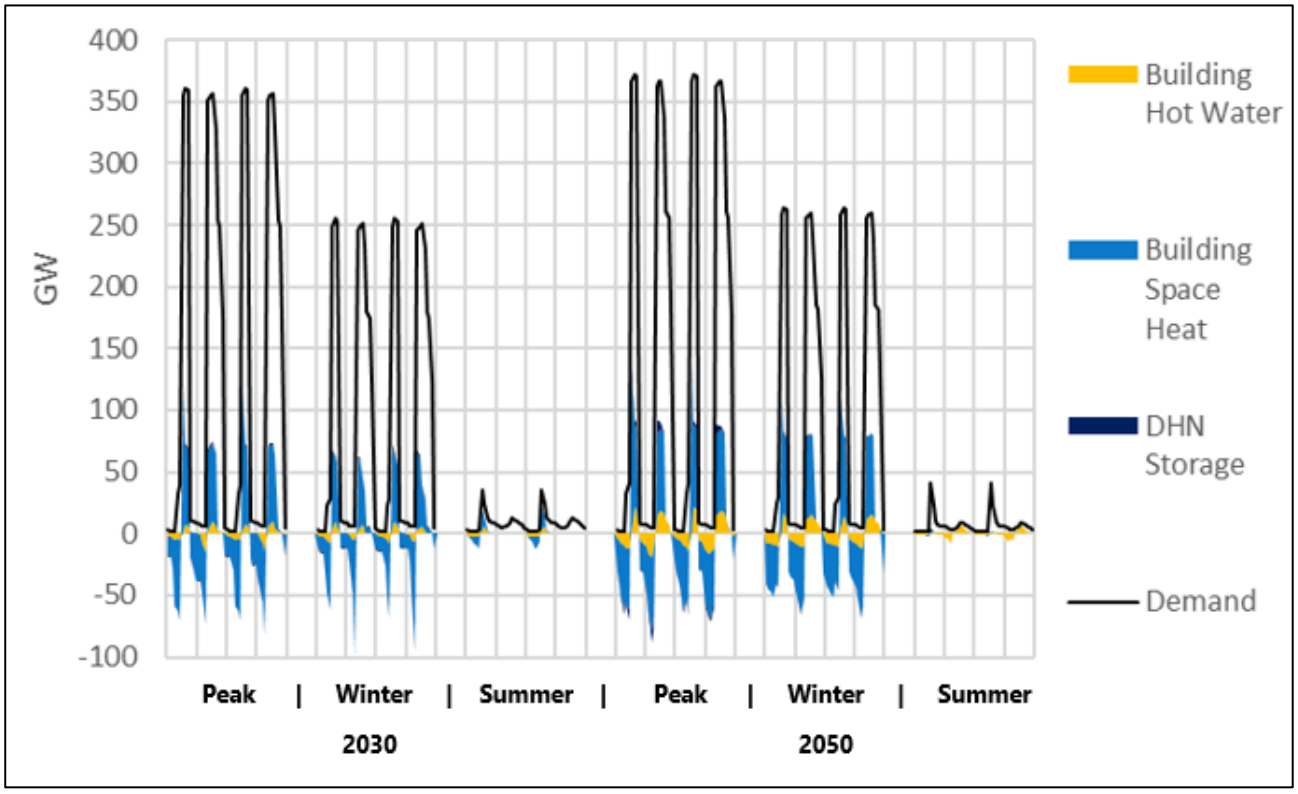

Figure 32: FA-SFM-UNF thermal storage dispatch

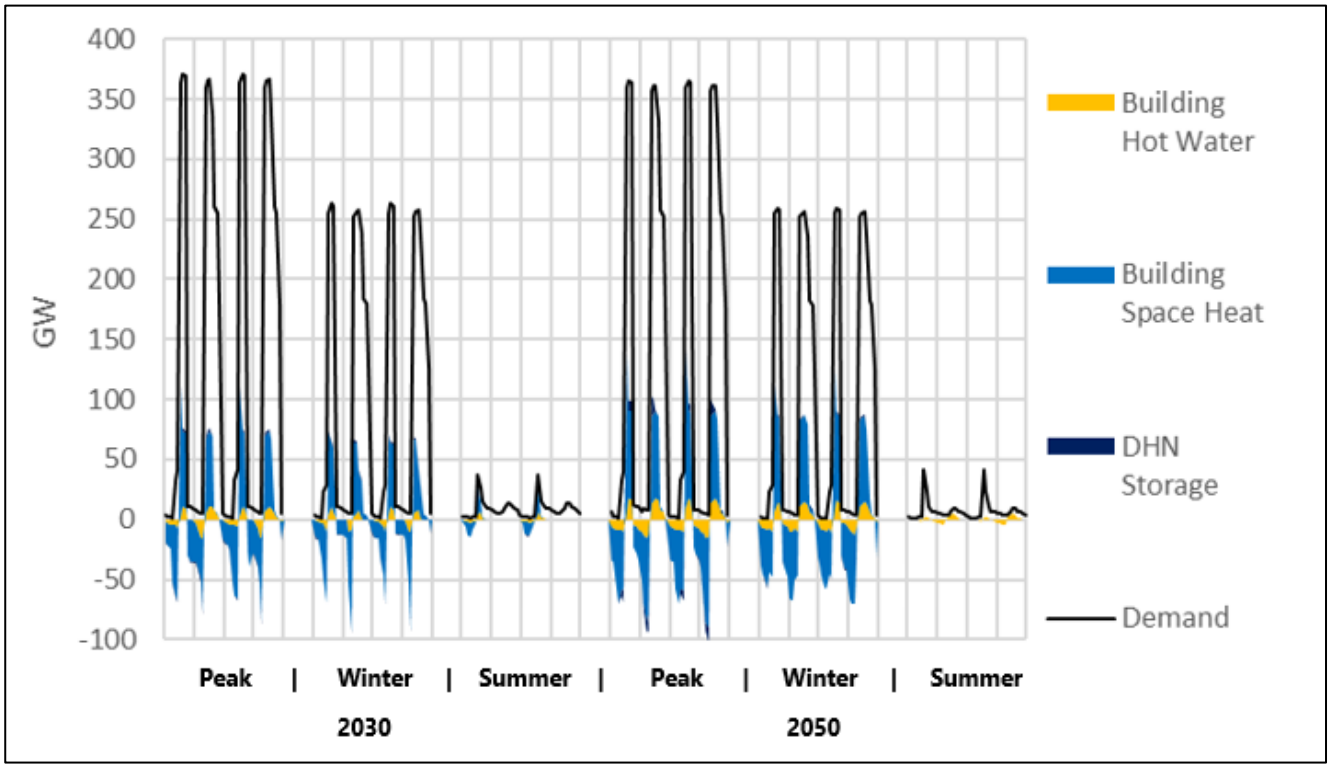

Figure 33: FA-SFM-125 thermal storage dispatch

4.8. Results – Cost Comparison

Key results:

- A whole system cost increase of £9bn/3% was found when comparing FA-SFM-125 with FA-SFM-UNF.
- This is a relatively small increase when comparing total system cost between two scenarios with radically different electricity system designs.
- Further work could provide additional benefit by carrying out more model runs to explore sensitivities – including how small variations in cost and performance of key technologies might affect the overall system cost impact of offshore wind, as well as how this cost differential might change across a range of offshore wind deployment levels.

Table 5 shows the annualised total system costs in 2030 and 2050 associated with each scenario. This includes the cost of all raw fuels, new investment, retrofit, and running costs. The definitions of each of the cost categories are given in Table 6. These costs are undiscounted and are in 2010 pounds.

In 2030 the costs of the two scenarios are almost identical. For both scenarios there is then a large increase to 2050, reflecting the effort required to meet Net Zero. Whilst there is a large increase under both scenarios by 2050, FA-SFM-125 adds an additional £9bn, or 3%, to the system cost.

Most of this increase is related to technology investment, adding £6bn, whilst transmission investment costs and resource costs also add £1.8bn and £1.3bn respectively. As a whole system model, variations in one area (in this case additional OSW) can have an impact on all parts of the system, and this makes it difficult to identify all of the exact causes for the increase in technology investment. Nevertheless, likely sources of this cost include the additional thermal generation required for the peak week, and the added long range natural gas storage. Although nuclear has a higher capital cost per GW than offshore wind, the higher load factor – particularly during peak periods – complements the characteristics of OSW, resulting in the optimum mix of higher and lower cost and load factor plant, at least overall system cost.

The increase in transmission cost is easier to identify and is due to the additional OSW deployment, which requires greater investment in costly offshore transmission network.

The higher deployment of OSW under FA-SFM-125 should reduce the resource cost as no 'fuel' is required. However, any value gained here is outweighed by the substantially greater natural gas consumption (notably for Steam Methane Reformation with CCS).

The cost difference found here of £9bn/3% is relatively small when comparing total system cost between two scenarios with radically different electricity system designs. Further work could provide additional benefit by carrying out more model runs to explore sensitivities – including how small variations in cost and performance of key technologies might affect the overall system cost impact of offshore wind, as well as how this cost differential might change across a range of offshore wind deployment levels.

Table 5: System Cost per scenario (£bns)

	2030		2050	
	FA-SFM-UNF	**FA-SFM-125**	**FA-SFM-UNF**	**FA-SFM-125**
Technology Investment	128.09	128.85	259	265
Storage Investment	2.62	2.30	11.52	11.14
Transmission Investment	0.53	0.78	5.42	7.22
Technology Retrofit	3.88	2.03	15.15	15.1
Technology Fixed	25.77	25.63	37.93	39.07
Storage Fixed	0.04	0.08	0.33	0.09
Storage Variable	0.12	0.14	0.39	0.34
Resource	44.95	45.03	17.62	18.92
TOTAL	**206**	**205**	**348**	**357**

Table 6: Cost category definitions

Cost category	Definition
Technology Investment	Capital cost of technologies deployed. 'Technologies' here means all assets represented in the model except those which are storage assets, part of the transmission networks, or retrofit costs. 'Technologies' thus includes electricity and heat generation, gas production, industry and transport.
Storage Investment	Capital cost of electric, thermal and gaseous storage technologies.
Transmission Investment	Capital cost of electric, natural gas and hydrogen transmission and distribution networks, except retrofit/repurposing costs.
Technology Retrofit	The capital cost of retrofitting technologies, and includes retrofitting dwellings, generation plants to include CCS, and repurposing the gas network to distribute hydrogen.
Technology Fixed	Fixed operational costs relating to technologies.
Storage Fixed	Fixed operational costs relating to storage technologies.
Storage Variable	Variable operational costs relating to storage technologies.
Resource	Cost of all resources consumed in SFM, e.g. natural gas, coal etc.

4.9. Conclusion and Recommendations

The key findings from the modelling and supporting analysis are outlined below. When considering these, it should be remembered that the results of SFM are least-cost energy system designs for given scenarios, rather than forecasts of what the energy system will look like (see Section 4.3). Important notes regarding interpretation of both the ESME and SFM modelling undertaken can also be found in section 3.1 of chapter 3 (Whole System Analysis).

<u>OSW Deployment, Curtailment and Nuclear Deployment</u>

- OSW plays a significant role out to 2050 under both scenarios. The relatively low cost of OSW, combined with its low carbon credentials, results in 70GW being deployed in the FA-SFM-UNF scenario (as a result of optimisation without any specified deployment level).
- In both scenarios just over 30% of wind generation is curtailed.
- By forcing an increased (125GW) deployment of offshore wind, the baseload provided by nuclear is displaced by wind across most seasons, with some support from solar PV. With this increased OSW deployment, nuclear deployment is reduced significantly under FA-SFM-125 to 8GW producing 37.3TWh annually by 2050, down from 37.4GW/290TWh. Nevertheless, the remaining nuclear generation provides benefit to the system – even at higher OSW deployment levels – by being available during periods of low renewable generation (peak week), thus reducing the need for thermal generation backup.

<u>System Services</u>

- The need for frequency response reduces in 2050 under both scenarios. For FA-SFM-UNF this is partly due to the 37GW of high inertia nuclear generation deployed, although for both scenarios it is largely because of the significant increase in electric demand which counteracts the lack of inertia provided by OSW (see section 4.5.4).
- However, the requirement for reserve replacement increases substantially under both scenarios; by 28GW under FA-SFM-UNF and 34GW under FA-SFM-125. Reserve replacement is required to cover unforeseen plant shortages and renewable forecast error; therefore the higher deployment of OSW in FA-SFM-125 leads to the greater increase in need for reserve replacement. Winter has the greatest requirement for reserve replacement under both scenarios as it has the highest levels of renewable dispatch. The calculations for reserve replacement are based on the way the System Operator currently calculates the need for reserve; As more renewable generation is added into the system this approach should be reviewed and revised as required.

<u>Interconnectors</u>

- In 2050, interconnectors are almost continuously importing energy during the peak and winter weeks. During the peak week this is due to the low availability of OSW (and solar PV). However, this is not the case during the winter week; interconnectors are assumed to import carbon free electricity (excess renewables and nuclear) and so are used during winter to help meet Net Zero. During the summer, high levels of solar PV generation combined with lower demand and wind result in significant exporting of electricity, although there is some importing under FA-SFM-125 during the evening peak. This is likely to be due to the reduction in solar PV during evening, low nuclear and relatively low wind.

- Interconnector deployment is an exogenous assumption in SFM. Under both scenarios it is assumed that 12GW are deployed by 2050. During the peak and winter weeks the interconnectors are used to import up to 12GW to meet demand, even though interconnector prices are assumed to be high during these periods. Given the high utilisation of interconnectors, it is suggested, although not proven, that greater interconnector capacity would be used if available. Therefore, further analysis is needed to investigate the benefits of interconnectors.
- Crucially, this further work should also examine the assumption that there will be sufficient carbon free electricity available to import, and demand to export, as required. Other European countries may be facing similar conditions (demand and available renewable resource) as the UK at the same time and so struggle to export low carbon electricity or to import electricity when the UK requires it. On the other hand, the larger geographical area of Europe and its interconnected nature may reduce this risk.

Electrical and Thermal Storage

- Electrical storage is high by 2050 under both scenarios, although FA-SFM-UNF sees a fractionally higher deployment of 78GW/333GWh compared to 72GW/275GWh under FA-SFM-125. Storage capacity is higher under FA-SFM-UNF despite the lower deployment of OSW due to the high level of nuclear generation and the use of other vectors to provide additional flexibility under FA-SFM-125.
- Electrical storage is used to balance supply and demand predominantly over the course of a day, with battery storage by far the most preferred technology. Under the higher deployment of OSW there is a significant level of storage which is only required during the peak season (~18GW).
- Building-level thermal storage is similar in both scenarios and increases significantly by 2050. This is due the electrification of the heat sector and the role of thermal storage to smooth electrified heat production and avoid coupling the electricity sector with high intra-day heat demand variation.

Natural Gas Storage

- Natural gas storage decreases between 2030 and 2050 under FA-SFM-UNF to around 400GWh by 2050. Natural gas storage increases under FA-SFM-125 between 2030 and 2050 to a total of 900GWh due to increased thermal generation for rare low-wind weeks, and the use of Steam Methane Reformation with CCS to produce hydrogen. However this is still low compared to the current level of ~27,000GWh[8]. Long range natural gas storage, which makes up the vast majority of natural gas storage, follows a seasonal charging cycle which levels out production seasonally and increases utilisation rates of natural gas production technologies.
- Natural gas linepack provides short term flexibility over peak periods only (shifting demand from morning and evening peaks to midday and overnight periods). In seasons where the system is less stressed (e.g. summer), the short-term flexibility available from long-range storage is sufficient to balance supply and demand, and linepack is not used.

Hydrogen Production and Storage

- Hydrogen production in 2050 is similar across both scenarios at 227TWh/annum and 234TWh/annum under FA-SFM-UNF and FA-SFM-125 respectively. Biomass and fossil fuel gasification + CCS, SMR + CCS, and electrolysis all contribute to hydrogen production under both scenarios.
- Large quantities of electrolysis result in relatively high whole system costs (when considering options for whole system designs), which alongside competition from interconnection leads to a modest contribution form electrolysis, producing 55TWh/annum and 35TWh/annum of hydrogen for FA-SFM-UNF and FA-SFM-125 respectively.
- The ability of electrolysis to produce zero-carbon hydrogen (recognised by SFM) makes it likely to be a key technology in meeting net zero targets, especially in the absence of high-capture-rate CCS. If the costs of green hydrogen (including total operational costs of the electrolysis and electricity generation) were considerably lower than the cost reduction curves already assumed in the modelling, then the whole system costs would be somewhat reduced – although the results are not strongly sensitive to electrolysis pricing, largely because of the system-wide implications of driving in more electricity generation). There is then potential for higher levels of deployment than modelled.
- No seasonal hydrogen storage is used in either scenario, although it is available as a technology option. The variation in demand for hydrogen is relatively small. This small variation can be managed without the need for seasonal storage. However, there is still the need for hydrogen storage, in the form of linepack, to help meet the daily swings; 68GW and 75GW of hydrogen linepack are deployed by 2050 FA-SFM-UNF and FA-SFM-125 respectively.
- If deployment of electrolysis was higher than modelled, perhaps for the reasons discussed in Section 4.6.1, then this may lead to an increased need for seasonal storage. However, for high deployments of seasonal hydrogen storage to occur it is likely that costs would have to reduce enough for hydrogen to displace electrification for significant levels of heating demand. Therefore, further work is recommended to quantify the potential value of seasonal hydrogen storage (a) in the event that green hydrogen became available at costs considerably lower than the cost reduction curves already assumed in the modelling and (b) for the avoidance of curtailment payments (if such payments remained part of a future market structure).

Overall System Cost

- The overall energy system cost increase found here of £9bn (3%) for the FA-SFM-125 scenario over the cost of the FA-SFM-UNF scenario is relatively small when comparing total system cost between two scenarios with radically different electricity system designs.
- Further work could provide additional benefit by carrying out more runs to explore sensitivities – including how small variations in cost and performance of key technologies might affect the overall system cost impact of offshore wind, as well as how this cost differential might change across a range of offshore wind deployment levels.

Impact of Peak Weeks

- The key trend which has occurred throughout this analysis is the stress put on the system during the peak season which is exacerbated in the high OSW scenario. The peak season roughly corresponds to a one in ten year event and is identified as a week where demand and interconnector prices are high, and wind and solar resource are low. This results in considerable generation and storage assets being built, across multiple vectors, just to cope with this period.
- The high OSW scenario has the greatest level of renewable generation and lowest level of nuclear generation, and so has the highest level of assets used only in this season – for example 100GW of thermal generation[13] and 18GW of electrical storage. Whilst from a system perspective this delivers the lowest cost energy system, it results in a significant number of assets which are highly unlikely to be commercially viable and so require policy support (see Task 4). Therefore, further analysis is needed to quantify what support would be required for these assets, and whether this negates the system benefits which these assets provide (see Task 5).

Summary of Conclusions

In summary, the modelling analysis reported in this chapter finds that significant levels of OSW (~70GW) provide value in a Net Zero system as part of a balanced energy mix. In this balanced system substantial flexibility measures (e.g. batteries, longer duration electric storage, thermal storage, peaking plant, and interconnectors) are required to balance renewable supply and maintain grid stability.

If OSW deployment is substantially higher than this (125GW) then additional flexibility measures (e.g. natural gas storage and peaking plant) are needed. Alongside higher transmission costs, this results in a modest increase in system cost of 3% by 2050. This cost difference is based upon current assumptions of performance and cost. Innovation, along with policy and regulation measures, have the potential to reduce many of the barriers to higher deployments of OSW, but are not represented in the modelling analysis. A number of these measures are discussed in subsequent chapters which report the analyses from Tasks 3, 4 and 5.

[13] Around 50GW of this capacity is also used to provide systems services, particularly reserve replacement which is discussed further in section 4.5.4. However, even in these cases this generation is used sparingly, either for short periods at a time (less than 1 hour) or in a backup capacity only to be used to cover forecast error or plant outages.

4.10. Appendix A: System Service Formulae

The following formulae are used in SFM to calculate systems service requirements and are taken from the ETI's Storage and Flexibility Model final project report[1].

Service	Formula
Frequency Containment	FC_req = **1.8** * Largest-in-feed-loss (MW) + **-0.0025** * Demand (MW) + **-4.5** * System Inertia (GVAs)
Frequency Replacement	FR_req = **1.3** * Largest-in-feed-loss (MW) + **-0.013** * Demand (MW) + **-0.34** * System Inertia (GVAs)
Reserve Replacement	RR_req = **19.25%** * Wind (MW) + **24.9%** * Solar (MW) + **4.5%** * Demand (MW) + Largest-in-feed-loss (MW)

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