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Coordinated Operational Methodology for Managing and Accessing Network Distributed Energy Resources (COMMANDER)

Workstream 2 Report - Techno-Economic Assessment of Alternative ESO-DSO Coordination Schemes

A report for National Grid ESO and National Grid Electricity Distribution

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# Executive Summary

Increased Distributed Flexibility Resources (DFRs) from small and medium-scale generators, energy storage, and demand response technologies connected at various distribution network voltage levels create opportunities and challenges for the ongoing energy system transformation. Coordination between the electricity system operator and distribution system operator is critical for grid stability, demand-supply balancing, integration of renewable energy, grid planning and investment, outage management, and efficient market operation. It enables effective grid management, ensuring a reliable and secure consumer electricity supply. Coordinating DERs to provide grid-flexibility services to both transmission and distribution networks will require significant data exchange and synergic decision-making processes between ESO and DSO that can be challenging given the different objectives those entities may have while trying to minimise the overall cost from the whole-system perspective.

In this context, this report aims to analyse the techno-economic assessment and system implications of alternative ESO-DSO coordination approaches on Great Britain's future energy system under different conditions to understand the value of improving ESO-DSO coordination. A range of case studies has been conducted to analyse the techno-economic performance of three different ESO-DSO coordination approaches: (i) ESO-led Business-as-Usual (BaU), (ii) Scheme 1: Enhanced Coordination, and (iii) Distributed Flexibility Coordinator. The studies aim to identify the enduring solutions for managing DFRs, and therefore, the studies were conducted on the 2050 net zero-emission system to ensure the effectiveness of the approaches on future sustainable energy systems. Flexibility from all technologies, including sector-coupling flexibility in electricity, gas and heating/cooling systems, has been considered.

The key findings can be summarized as follows:

**Distributed flexibility should be facilitated to minimise the system costs**

* Harnessing and utilising distributed flexibility resources saves the annual system costs between 7.4- 7.8 £bn/year in H2 and 9-11.3 £bn/year in ELEC.
* Electrification is one of the major drivers for utilising distributed flexibility resources. Therefore, the benefits of distributed flexibility are higher in deep electrification. Therefore, it requires a more holistic approach to coordinating distributed flexibility resources. It is worth noting that electrification occurs in both hydrogen and deep electrification pathways in different magnitudes; hence, deploying distributed flexibility resources is relevant in both scenarios.
* The savings can be achieved if there is some investment in flexibility sources such as heat storage, electricity storage, and demand response technologies. Given the cost assumptions used in the study, the cost of procuring and utilising distributed flexibility is much lower than its benefits.
* The main savings attributed to distributed flexibility are in the mitigation cost of investment in low-carbon power generation and distribution networks. Customers' flexibility also reduces end-users' appliance costs, such as heat pumps. Heat storage can reduce the size of heat pumps needed. Moreover, the savings happen not only in the electricity sector but also in other system costs, such as the reduced investment needed in electrolysers and hydrogen storage.

**Benefits of improving ESO – DSO coordination schemes**

* Improving the ESO-DSO coordination approach from the BaU to Scheme 1 and 2 will reduce the cost of the future system by 0.3 – 0.9 £bn/year in the hydrogen scenario and 1.1 – 4.3 £bn/year in the deep electrification scenario. If the future system is moving towards full electrification of heat and transport, the case for improving ESO-DSO coordination would be stronger than the one with hydrogen heating. The performance of Scheme 1 and 2 would be relatively similar if all the coordination processes could be carried out smoothly. However, Scheme 1 may pose a higher risk for suboptimal conditions such as a lack of ESO's ability to incorporate small-scale DFR providers to its control centre, exposure of stricter primacy rules to DSOs to provide sufficient headroom to deal with uncertainty in the provision of services and network capacity, higher cost of DFRs and lower number of service providers due to lack of market competition and transparency. These suboptimality conditions may increase the system costs by up to £4.28bn/year. Therefore, Scheme 2 could be an option to derisk these conditions.
* While the cost of improving the coordination has not been considered, the cost is likely to be lower than the benefits. Further detailed studies are recommended to understand what needs to be provided to enable such coordination and the associated costs.
* Different coordination schemes will affect the energy system's investment and operational costs. The impacts are beyond the electrical transmission and distribution systems; therefore, it is crucial to decide carefully as it has long-term effects.
* The benefits of Schemes 1 and 2 are also higher in the FES 2022 "System Transformation" scenario (note: the core scenario used in the study is based on "Leading the Way"), which has a higher energy demand and without demand response. Without demand response, the amount of electricity storage needed in the system to provide flexibility increases substantially, and most of them will be located at distribution as it can also be used to manage distribution network constraints. Hence, this increased distributed electricity storage will also increase ESO and DSO's operational challenges; therefore, stronger coordination will be needed.
* Other conditions, such as the lower cost of wind, may also increase the need for coordination but not always occur in all cases we simulated. As the wind is already very dominant in the core scenarios, increasing slightly more wind due to its lower cost will not affect the system performance so much and the need for flexibility.
* Higher distributed flexibility costs may slightly reduce the case for improving coordination, but the impact is marginal, and the savings are still positive.

The studies also demonstrate that DFRs will be distributed across the GB system. Higher penetration of electricity storage can occur in the Northern GB due to high capacity factors of offshore wind in those areas but in general, both energy storage and demand response technologies will be spread across the GB. Therefore, ESO – DSO coordination will be required across the GB system.

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# Abbreviations

|  |  |
| --- | --- |
| ATR | Auto Thermal Reformer that produces hydrogen from natural gas |
| BaU  BECCS | Business-as-Usual, i.e. ESO led coordination scheme  BioEnergy plants with CCS. BECCS produces hydrogen or power |
| BEIS | Department for Business, Energy and Industrial Strategy |
| CCGT | Combined Cycle Gas Turbine (natural gas) |
| CCS | Carbon Capture and Storage. In power generation, it refers to CCGT with CCS |
| CE | Continental Europe |
| DACCS | Direct Air Carbon Capture and Storage |
| DER  DFR  DSO | Distributed Energy Resources  Distributed Flexibility Resources  Distribution System Operators |
| DR | Demand Response |
| DH | District Heating |
| ELEC  H2 | Deep electrification heat decarbonisation pathway  Hydrogen heat decarbonisation pathway |
| HP | Heat Pumps |
| IE | Ireland |
| IWES | Integrated Whole Energy System model |
| LCoE | Levelised Cost of electricity |
| PV  S1  S2 | Photovoltaic  Scheme 1: Enhanced ESO and DSO coordination using a two-stage system optimisation  Scheme 2: Distributed Flexibility Coordinator as an integrated approach |

# Introduction

## Background

Increased Distributed Flexibility Resources (DFRs) from small and medium-scale generators, energy storage, and demand response technologies connected at various distribution network voltage levels create opportunities and challenges for the ongoing energy system transformation. Coordination between the Electricity System Operator (ESO) and the Distribution System Operator (DSO) is crucial for the efficient and reliable operation of the overall electricity grid. Here are several reasons why their coordination is important:

1. Grid Security and Stability: The ESO is responsible for maintaining the security and stability of the high-voltage national transmission system, while the DSO manages the lower-voltage regional distribution network that connects directly to consumers. *These two parts of the grid are interconnected, and any imbalances or disruptions in one can affect the other.* Effective coordination between the ESO and DSO ensures the grid operates within safe limits and prevents cascading failures.
2. Demand and Supply Balancing: The ESO manages and balances the bulk electricity supply with the overall demand. On the other hand, the DSO handles the local distribution network and manages the electricity flows at a smaller scale. By coordinating their efforts, the ESO and DSO can optimize the utilization of generation resources, avoid congestion in the grid, and ensure that supply matches demand in real-time.
3. Integration of Renewable Energy: As renewable energy sources like wind and solar power become more prevalent, the coordination between the ESO and DSO becomes even more crucial. Some renewable energy generation is decentralized and connected to the distribution grid, requiring the DSO to manage the intermittent and variable power flows. At the same time, remote renewable sources such as offshore wind in the North Sea require sufficient balancing sources from distributed loads. The ESO and DSOs must monitor these distributed resources and balance their generation with the grid demand. Close coordination ensures smooth integration and maximizes the utilization of renewable energy sources.
4. Grid Planning and Investment: The ESO and DSO should collaborate on grid planning and investment decisions. The ESO considers the long-term development of the high-voltage transmission system, including new interconnections and large-scale generation projects. The DSO focuses on the local distribution network and considers factors like load growth, decentralized generation, and infrastructure upgrades. Coordination between the two ensures that the grid infrastructure is developed in a coordinated and cost-effective manner, avoiding duplication of efforts and unnecessary investments.
5. Outage Management and Restoration: During grid disturbances or outages, the ESO and DSO must work together to identify the source of the problem, isolate affected areas, and restore power as quickly as possible. Effective coordination enables efficient communication, rapid response, and optimal utilization of resources, minimizing the duration and impact of outages on consumers.
6. Market Operation: Stronger ESO and DSO coordination is vital for market operations in deregulated electricity markets, where multiple entities generate and supply electricity or energy arbitrages and flexibility as ancillary services. The ESO manages the wholesale market and ensures fair competition, while the DSO facilitates the connection of new market participants, manages grid access, and enables efficient retail competition. Seamless coordination between the two promotes market efficiency and enhances the overall functioning of the electricity market.

Coordinating DERs to provide grid-flexibility services to both transmission and distribution networks will require significant data exchange and synergic decision-making processes between ESO and DSO that can be challenging given the different objectives those entities may have while trying to minimise the overall cost from the whole-system perspective.

## Objectives

In this context, this report aims to analyse the techno-economic assessment and system implications of alternative ESO-DSCO coordination approaches on Great Britain's future energy system under different conditions to understand the value of improving ESO-DSO coordination. Some works have been carried out to enable this type of analysis, including:

* Enhancement of the Integrated Whole Energy System (IWES) model to represent the developed ESO/DSO coordination schemes;
* Defining the simulation scenarios to reflect the use cases for assessing the coordination schemes. The system used for the studies considers particular geographic locations of the networks, specific types of flexibility services, and different technology types of flexibility services;
* Mapping the use cases onto the model developed to quantify and assess the costs and benefits associated with the techno-economic performance of the different ESO/DSO coordination schemes;
* Quantifying and assessing the technical costs and benefits of different ESO/DSO coordination schemes.

## Summary of case studies

A range of case studies has been analysed to analyse the techno-economic performance of different ESO-DSO coordination approaches, focusing on the 2050 net zero-emission system to ensure the effectiveness of the approaches for a future sustainable energy system. It is envisaged that all flexibility resources would be facilitated, including sector coupling flexibility between electricity, gas and heating/cooling systems. Three different coordination approaches have been investigated, i.e.:

* Business as usual as the Counterfactual
* Scheme 1: Enhanced Coordination
* Scheme 2: Distributed Flexibility Coordinator

The approaches are described in more detail as follows.

### Business-as-Usual as the Counterfactual

Currently, the ESO has a central role in procuring and dispatching the flexibility sources for balancing and supporting the operational integrity of the national grid system. Some of the ESO's flexibility sources are connected to distribution networks. While the current arrangement dictates a certain minimum size of providers, in future, small-scale flexibility providers can be aggregated to participate in the flexibility market run for the ESO. As the Counterfactual scenario, we assume that the current mechanism will continue with some refinement and that aggregation of small-scale resources will happen to facilitate access and some control to those small grid-service providers.

Figure **1**‑**1** shows the interaction between ESO, DSO and flexibility providers in the Business as Usual Scheme. While the ESO objective is to minimise the overall system cost, ESO may not sufficiently capture the impact of using flexibility resources on the distribution network leading to a suboptimal balance of using distributed flexibility resources to reduce the cost of national energy systems and regional or local distribution networks.

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Figure 1‑1 Interactions among different system actors in the Business as Usual Scheme based on ENA Open Networks' Future World D

In this scheme, DSO will ensure that the application of DFR to support transmission system operation can be accommodated by sufficiently strong distribution networks.

### Scheme 1: Enhanced Coordination

Scheme 1 is developed based on the This scheme supports greater operational coordination than would be the case under a single entity-led scheme. DFR resources will be optimised using two key stages.

* + The first stage is for the DSO to use DFR to manage distribution network operation, minimise distribution network reinforcement, aggregate the available DFR resources that ESO can use considering local distribution network constraints and inform that information to the ESO.
  + Based on that information, the ESO will optimise and allocate the DFR services in all DSO regions in coordination with large-scale flexibility resources at transmission in the second stage to support the national transmission system at minimum cost.
  + Key design principles underpinning Scheme 1 are:
  + DSO will act as a local energy and ancillary service market facilitator for all DFRs.
  + DSO provide dynamic regional operational boundaries of DFR services that ESO can use after considering the local network constraints and the distribution network reinforcements. The operational boundaries vary depending on the availability of resources, load levels, and network conditions.
  + ESO will maintain visibility and control access to DFR directly or through aggregators and operate within the boundaries given by the DSO in advance.
  + ESO and DSO will exchange information regarding the volume of services being procured and activated, and DSOs will include those in their investment and operational planning.

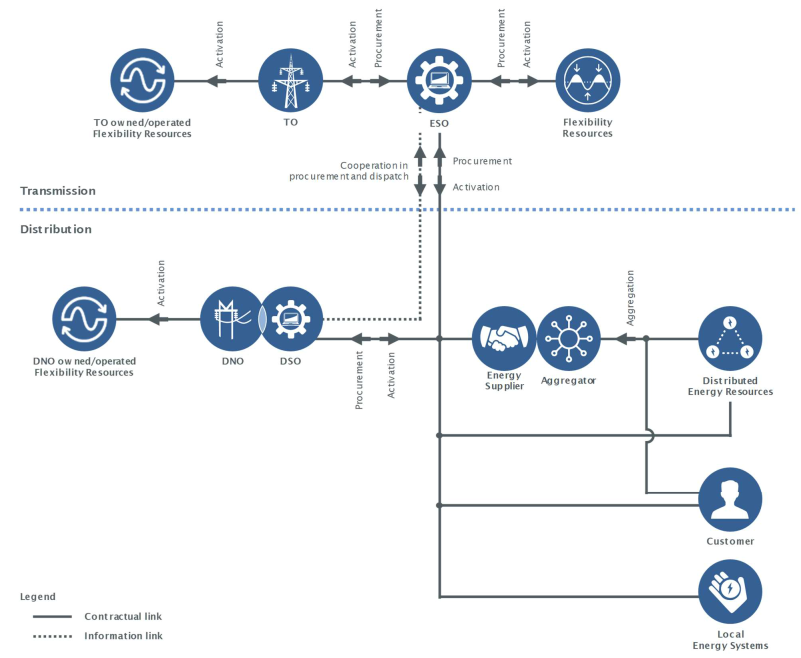


Figure 1‑1 Interactions among different system actors in Scheme 1 based on ENA Open Networks' Future World B

### Scheme 2: Distributed Flexibility Coordinator

Under this scheme, both the ESO and DSO have full access to DSR flexibility services, with decisions about access to services determined on an operational basis by a Distributed Flexibility Coordinator (DFC). Key design principles underpinning Scheme 2 are:

* + DFC acts as a neutral market facilitator for all distributed flexibility sources, ESO and DSOs. ESO and DSOs can access the full potential of distributed flexibility capacities.
  + DFC is responsible for collecting service requirements from ESO and DSOs and volumes and costs associated with distributed flexibility services, optimising those across all timescales and identifying procurement solutions for ESO and DSOs.
  + There is a joint flexibility procurement platform as part of an integrated system with visibility and managed access for all relevant stakeholders.

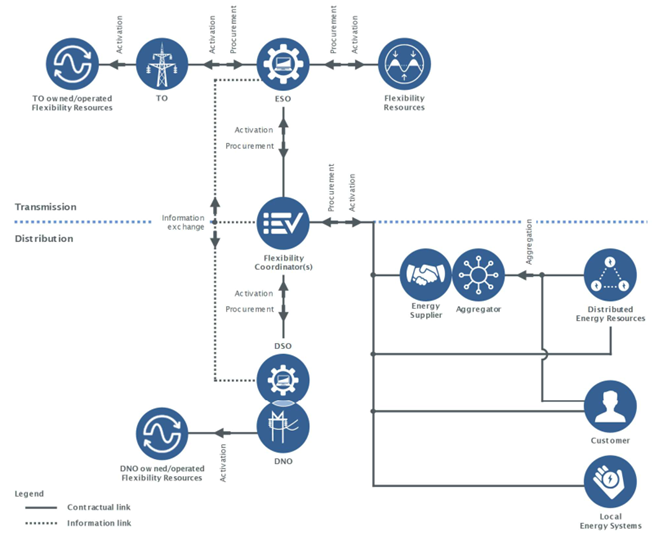


Figure 1‑2 Interactions among different system actors in Scheme 2 based on ENA Open Networks' Future World E

We recognise that significant complexity would need to be addressed to achieve coordination in operational timescales, including addressing multiple current barriers that are not driven by the independence of the coordinating body. Some examples of this include managing competing timescales when a party becomes aware they need a service and when delivery is required, access to sufficiently granular data and systems to store and process it, and the trade-off between security of supply and local constraints with priority potentially differing, depending on alternative options that are available at each location.

### Core study scenarios

In addition to the three coordination approaches, another counterfactual scenario ("0") is evaluated in which low-distributed flexibility resources are not used in the system. The objective is to quantify the system benefits of using DFRs. The core study scenarios are summarised in Table 1‑1.

Table 1‑1 List of core study scenarios being studied

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **0: Low-distributed flexibility services** | **Business-as-Usual (BaU)** | **Scheme 1: Enhanced Coordination** | **Scheme 2: Distributed Flexibility Coordinator** |
| ESO-DSO access coordination | Not coordinated | ESO-led | Sequential  2-stages | Integrated by DFC |
| Availability of distributed flexibility services | No DSR  Limited distributed storage (3GW at current level) | High | High | High |
| Sector-coupling flexibility | Yes | Yes | Yes | Yes |

As the flexibility requirements are system specific, we analyse two main scenarios of future energy systems where the heating demand is decarbonised through hydrogen ("H2") as the first scenario and through electrification ("ELEC") using electric heating ( a combination of heat pumps and resistive heating) as the second scenario. Details of the energy system backgrounds and assumptions used in the studies can be found in Appendix A.

## Summary of the approach

An integrated whole energy systems model (IWES) was used to quantify the system impacts of different scenarios. IWES is a least-cost optimisation model that minimises long-term investment and short-term operating costs across multi-energy systems (electricity, heating, hydrogen) from the supply side, and energy network to the end-customers while meeting the required carbon targets and system security constraints. IWES also optimises the deployment of flexibility technologies such as energy storage (thermal, electricity, hydrogen), demand response technologies (e.g. smart electric vehicle charging system with and without vehicle-to-grid capability, industrial and commercial sector demand response), interconnection with Europe, electrolysers, and generation flexibility to ensure adequate generation capacity during the peak demand with low renewable outputs.

Figure 1‑2 illustrates the interactions across different system components considered in IWES. Figure 1‑3 shows that the model considers the energy system from the local district level to a national system and the UK and European energy systems' interactions. IWES also considers the system's operational requirements, such as frequency response and reserves (which has a timeframe of milliseconds to minutes), dispatch problems (hours, days or seasons), and long-term investment problems (years) simultaneously.

Diagram, schematic

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Figure 1‑2 Integrated whole-energy system model

Diagram

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Figure 1‑3 Temporal and spatial aspects considered in IWES

Annual system costs and the energy system infrastructure proposed by the model in different scenarios can be compared to analyse the factors influencing the techno-economic performance of different ESO-DSO coordination approaches. A more detailed description of the model can be found in Appendix B.

# System Benefits of Alternative ESO-DSO Coordination Schemes

The benefits of improving ESO and DSO coordination were analysed qualitatively with a lack of quantitative evidence and comprehensive insight into how different coordination schemes may impact future energy system development. Hence, the importance of improving ESO-DSO coordination becomes unclear, which does not motivate faster progress in this area. In that context, our studies aim to provide more insight through quantitative studies to understand better how different coordination schemes would affect system development and system costs.

## Annual system cost performance

Figure 2‑1 shows the annual system costs[[1]](#footnote-2) of different cases in two heat decarbonisation scenarios, i.e. H2 (hydrogen) and ELEC (deep electrification).

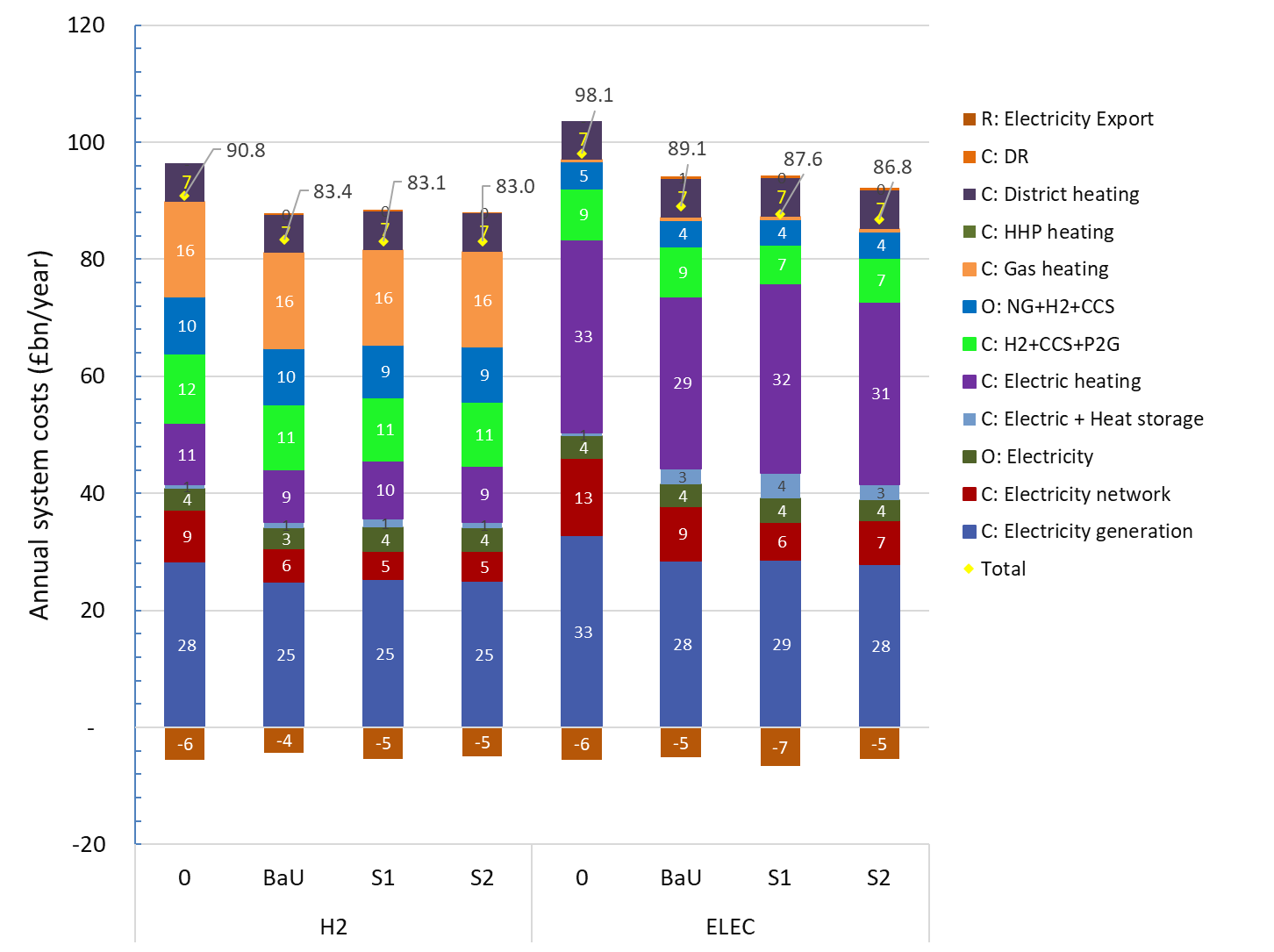


Figure 2‑1 Annual system cost performance of various cases

The annual system costs include the CAPEX investment (C:) of electricity generation, electricity network (transmission, distribution, interconnection), energy storage, heating appliances (electric, gas), district heating system, hydrogen supply, network, storage, and Carbon Capture and Storage (CCS) infrastructure, and demand response (DR) flexibility resources, OPEX (O:) of electricity, hydrogen and CCS systems. As the model suggests that Great Britain will be the net exporter of electricity in future, the cost of energy being exported will need to be offset from the annual system costs (R: Electricity export). All CAPEX are presented in annual costs considering different lifetimes and financing costs of different technologies in the model. This approach allows the costs to be summed up with the annual OPEX to enable direct comparison with the costs of different systems proposed by the model influenced by the selected coordination schemes.

The modelling results demonstrate:

* Harnessing and utilising distributed flexibility resources saves the annual system costs between 7.4- 7.8 £bn/year in H2 and 9-11.3 £bn/year in ELEC. Business-as-Usual approach already captures 80% - 95% of the economic benefits of distributed flexibility resources. *It is worth noting that the analysis does not include the costs of implementing the schemes, and therefore, the savings are gross.*
* Electrification is one of major drivers for utilising distributed flexibility resources. Electrification occurs in both hydrogen and deep electrification pathways in different magnitudes. Therefore, deep electrification requires a more holistic approach to coordinating distributed flexibility resources.
* Different coordination schemes will affect the energy system's investment and operational costs; therefore, it is crucial to decide it carefully as it has long-term effects.
* Figure 2‑2 shows the savings (negative changes) and additional costs (positive changes) in different cases (BaU, Scheme 1[S1], Scheme 2[S2]) against the counterfactual scenario ("0"). The main savings attributed to distributed flexibility are in the mitigation cost of investment in low-carbon power generation and distribution networks. Customers' flexibility also reduces end-users' appliance costs, such as heat pumps. Heat storage can reduce the size of heat pumps needed. Moreover, the savings happen not only in the electricity sector but also in other system costs, such as the reduced investment needed in electrolysers and hydrogen storage.
* The savings can be achieved if there is some investment in flexibility sources such as heat storage, electricity storage, and demand response technologies. There are also some additional costs offsetting the savings coming from alternative lower-cost technologies to supply heat (e.g. resistive heating [RH]) and hydrogen production technologies such as Auto Thermal Reformers (ATRs). The cost of procuring and utilising distributed flexibility is much lower than its benefits.

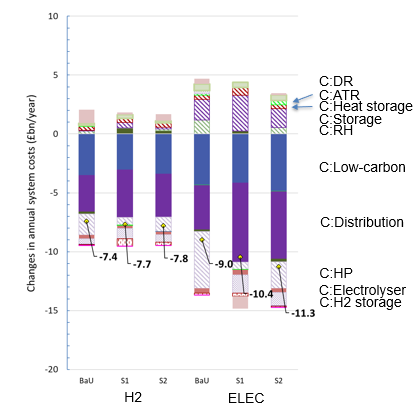


Figure 2‑2 Changes in annual systems costs due to distributed flexibility sources with different coordination schemes

## System benefits of improving coordination schemes

Focusing on the benefits of improving ESO-DSO coordination, we use the results of BaU scheme as the counterfactual and analysed the changes in the system cost attributed to the application of Scheme 1 (S1) and Scheme 2 (S2) against the BaU case. Although the BaU approach captures 80% - 95% of the economic benefits of distributed flexibility resources, improving the coordination can save a further 0.4 – 2.3 £bn/year, which is still a substantial cost saving. The results are shown in Figure 2‑3.

The results indicate the following:

* Compared with the BaU approach, which is ESO-led coordination, Schemes 1 and 2 savings are mainly in distribution network costs and flexibility provided by the hydrogen system, which can be substituted by distributed flexibility (electricity, heat storage and demand response). There are increased requirements for more efficient electric heating as the investment in heat pumps increases (compensated by the reduction in resistive heating cost).

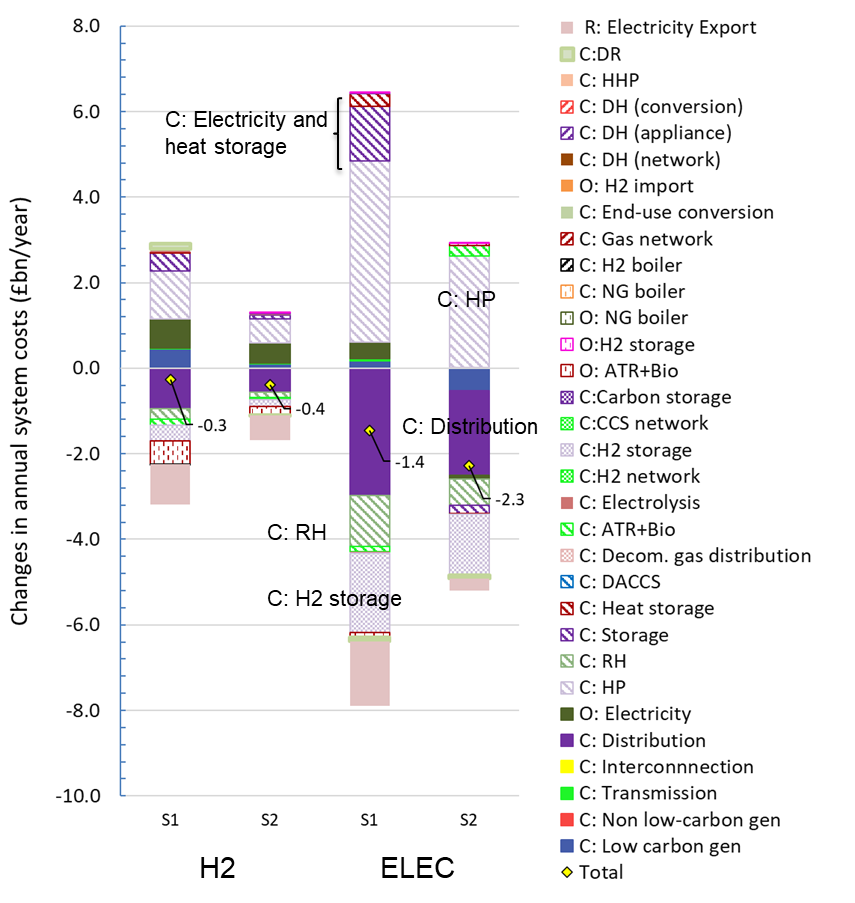


Figure 2‑3 Changes in annual system costs due to the shift from BaU to Scheme 1 and 2

* The benefits of S1 and S2 in H2 are lower than those in deep electrification. Again, this highlights the need for moving to S2, especially in the deep electrification scenario. However, if the future system relies on hydrogen for decarbonising heating, the business case for improving the BaU approach becomes less.
* The total magnitude of changes in S2 compared to BaU is less than in S1. The results suggest that the transition from BaU to S2 relatively involves fewer changes than the transition to S2.

## Impact of alternative coordination schemes on distribution electricity peak demand

One of the key challenges in coordinating ESO – DSO usage of distributed flexibility resources is finding the economic balance when applying those resources may create conflicts. As wind power is expected to be the dominant energy source in future, a scenario where demand needs to increase following wind output becomes more likely. However, shifting demand to follow wind may increase electricity peak demand, and therefore, it requires a sufficiently strong distribution network to allow that flexibility to happen. The modelling results illustrated in Figure 2‑4 provide insight into the impact of different cases on the electricity peak demand at distribution.

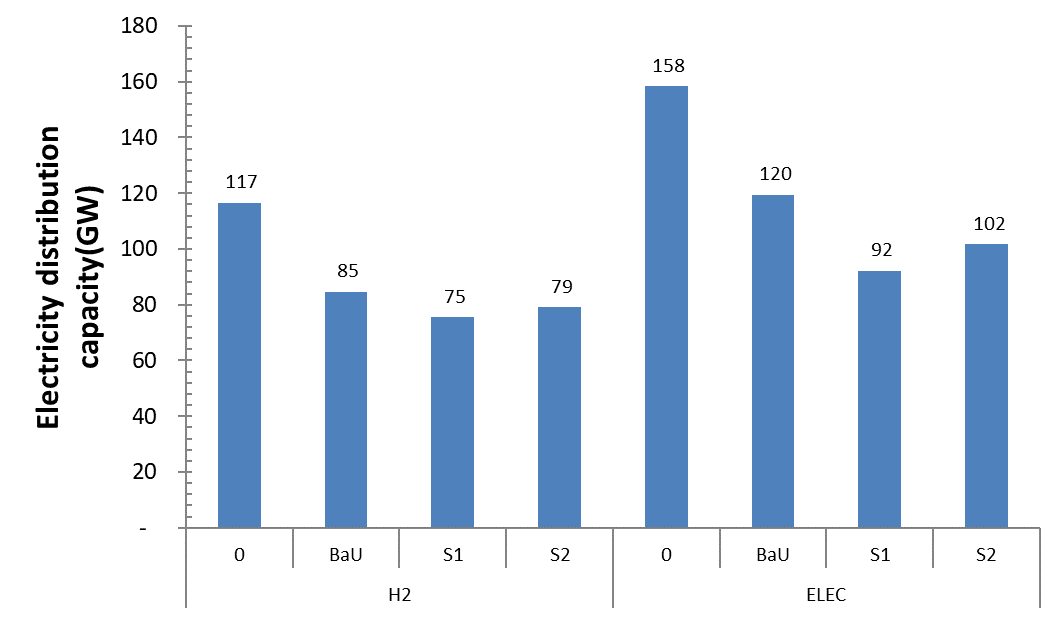


Figure 2‑4 Electricity distribution capacity under different coordination schemes

The modelling results demonstrate:

* Electrification will drive substantial distribution network reinforcement in H2 and ELEC scenarios without harnessing and utilising distributed flexibility resources. As a reference, currently, the electricity peak demand is around 60 GW which reflects the ability of distribution to meet that peak demand while providing a certain headroom for security. Electrification will drive the peak demand up to 158 GW (in deep electrification), 2.5 times the current peak demand. Even when some heating demand is decarbonised through hydrogen heating, the peak demand will increase about two times.
* Harnessing and utilising distributed flexibility resources, even in BaU, can reduce the required electricity distribution network capacity. However, across three coordination schemes, BaU requires the highest capacity as the impact of using DER services on distribution is less considered forcing distribution to be stronger.
* A better coordination scheme reduces further distribution capacity requirements. S1 is more DSO oriented, leading to the lowest requirement of distribution network capacity.
* S2 incentivises a higher distribution capacity than S1 (but less than BaU), enabling more flexibility from DER to be harnessed to support the system operation.

It is worth noting that having a strategy to minimise distribution network reinforcement cost is not the best strategy as it constrains the flexibility of distributed resources to support national energy systems.

## Impact of different coordination schemes on annual electricity demand

Distributed flexibility resources work in tandem with the flexibility provided at the transmission level. One of the technologies providing flexibility at transmission is large-scale electrolysers[[2]](#footnote-3). Our analysis shows that larger electrolyser activities (shown by a higher annual electricity load of electrolysers) occur when there is low availability or constraints of distributed flexibility. The annual electricity load of different system components are shown in Figure 2‑5.

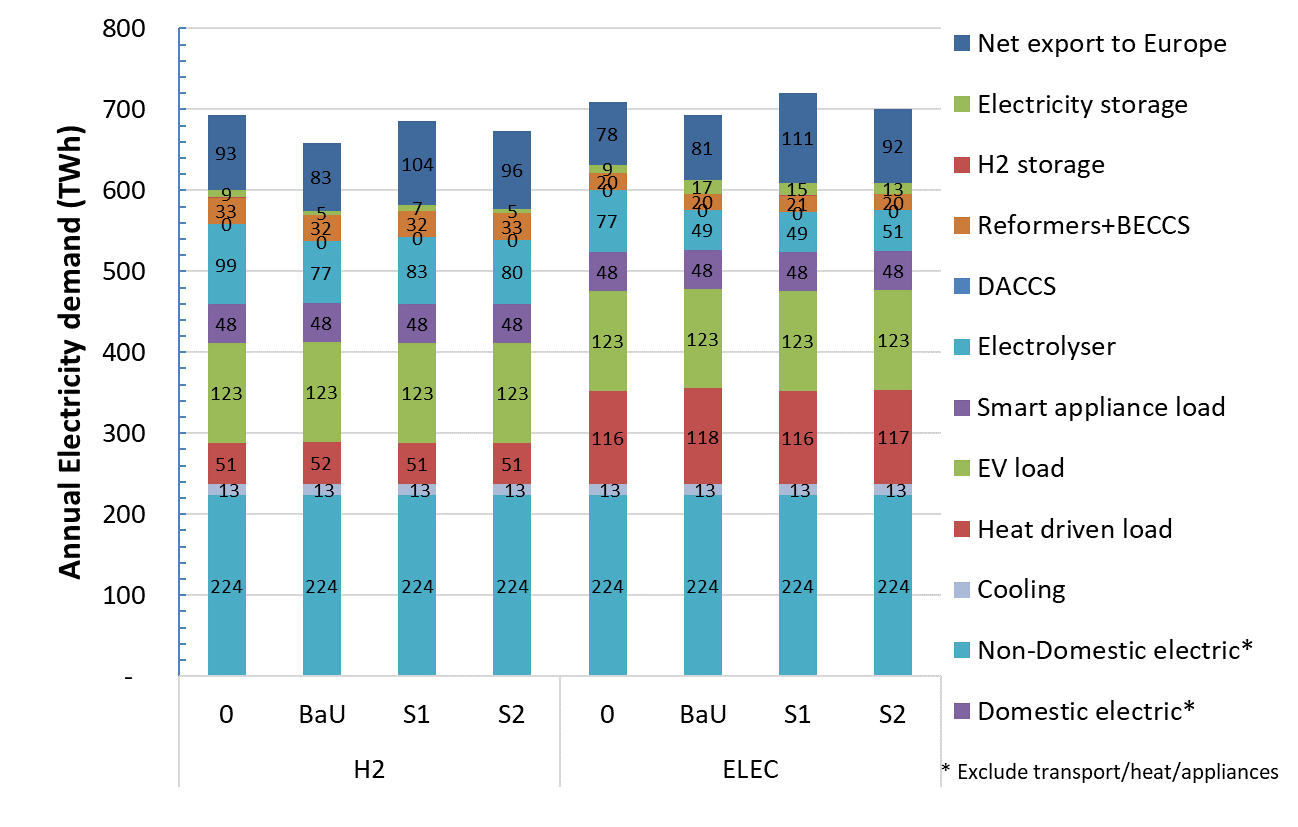


Figure 2‑5 Annual electricity demand in different cases

Excluding the electricity exported to Europe, the application of distributed flexibility resources can reduce GB's annual electricity demand consumption due to the reduction in the electrolyser's load mainly. Different coordination schemes do not substantially affect the annual load. While distributed electricity storage load increases in ELEC. The results demonstrate synergy between flexibility sources at different levels, which will increase the complexity and responsibility of the ESO to ensure that those resources are coordinated effectively.

## Impact of different coordination schemes on optimal generation mixes and electricity production

Another interesting modelling result is the impact of different approaches on optimal generation mixes. The optimal power generation portfolios of different cases are shown in Figure 2‑6. While the key issue addressed in this study is about different ESO-DSO coordination schemes, the importance of this issue exceeds the transmission and distribution development. As shown previously in Figure 2‑2, one of the main savings attributed to distribution flexibility resources is the reduction in the low-carbon generation investment.

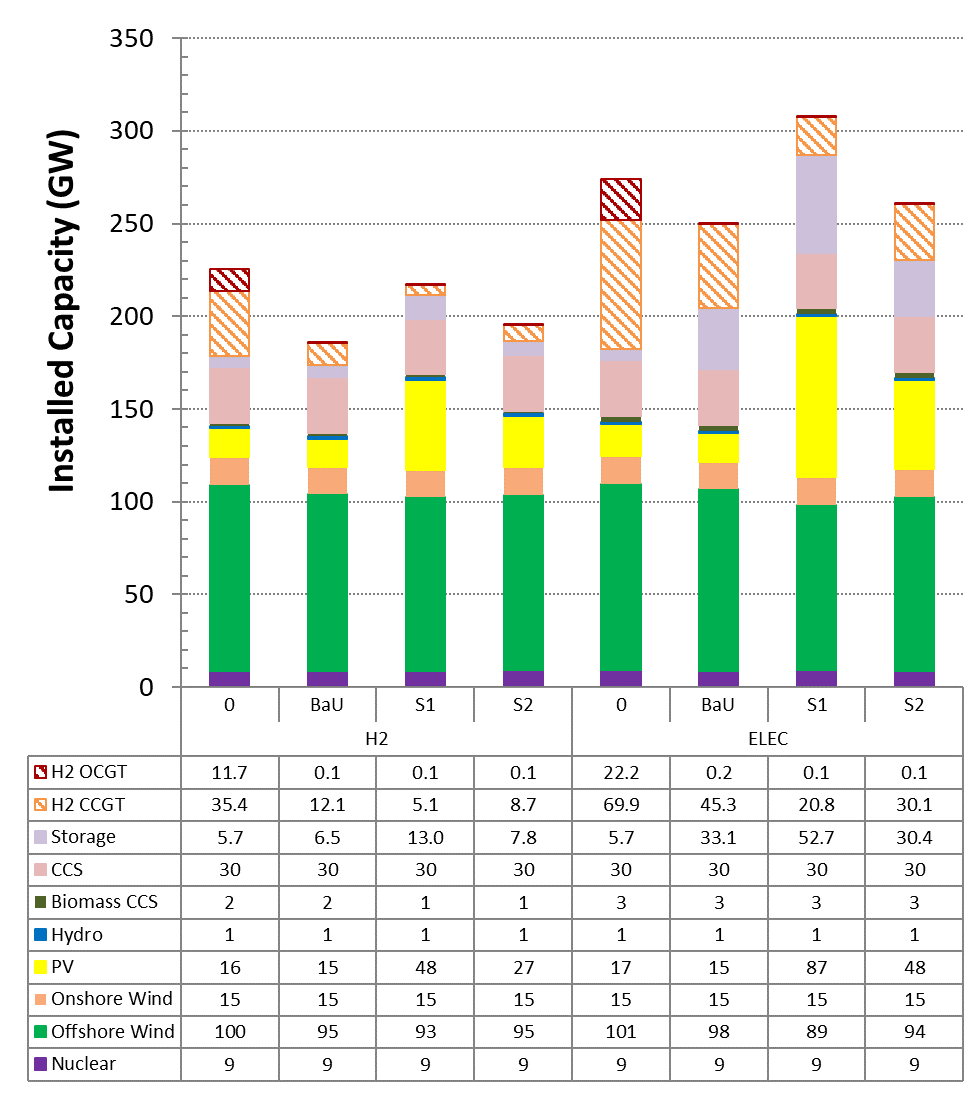


Figure 2‑6 Impact of different coordination schemes on optimal generation mixes

There are some insights we learned from the modelling result, i.e.

* Reiterating the synergy between transmission and distribution flexibility resources discussed earlier, we observe the higher capacity of hydrogen-fired power generation, i.e. hydrogen combined cycle gas turbine (H2 CCGT) and open cycle gas turbine (H2 OCGT) as transmission-connected flexibility providers in a system with low distributed flexibility services. The role of hydrogen generation is to provide balancing and other ancillary services and firm capacity to meet the peak demand. Distributed flexibility resources substitute the capacity of those hydrogen generators.
* The lowest total generation and electricity storage capacity is found in BaU, primarily driven by less solar PV and electricity storage capacity compared to the other Schemes (S1 and S2).
* S1 incentivises the development of more PV and distributed storage to deal with distribution congestion due to increased electrification.
* S2 provides a more balanced mix between BaU and S1.

All electricity supply will come from low or zero-carbon technologies to meet the net-zero emissions. However, more than 75% will come from variable renewable sources, increasing demand for system flexibility for balancing and dealing with variability, uncertainty and intermittency in generation output. Figure 2‑7 shows the optimal electricity production mixes from different technologies in different cases.

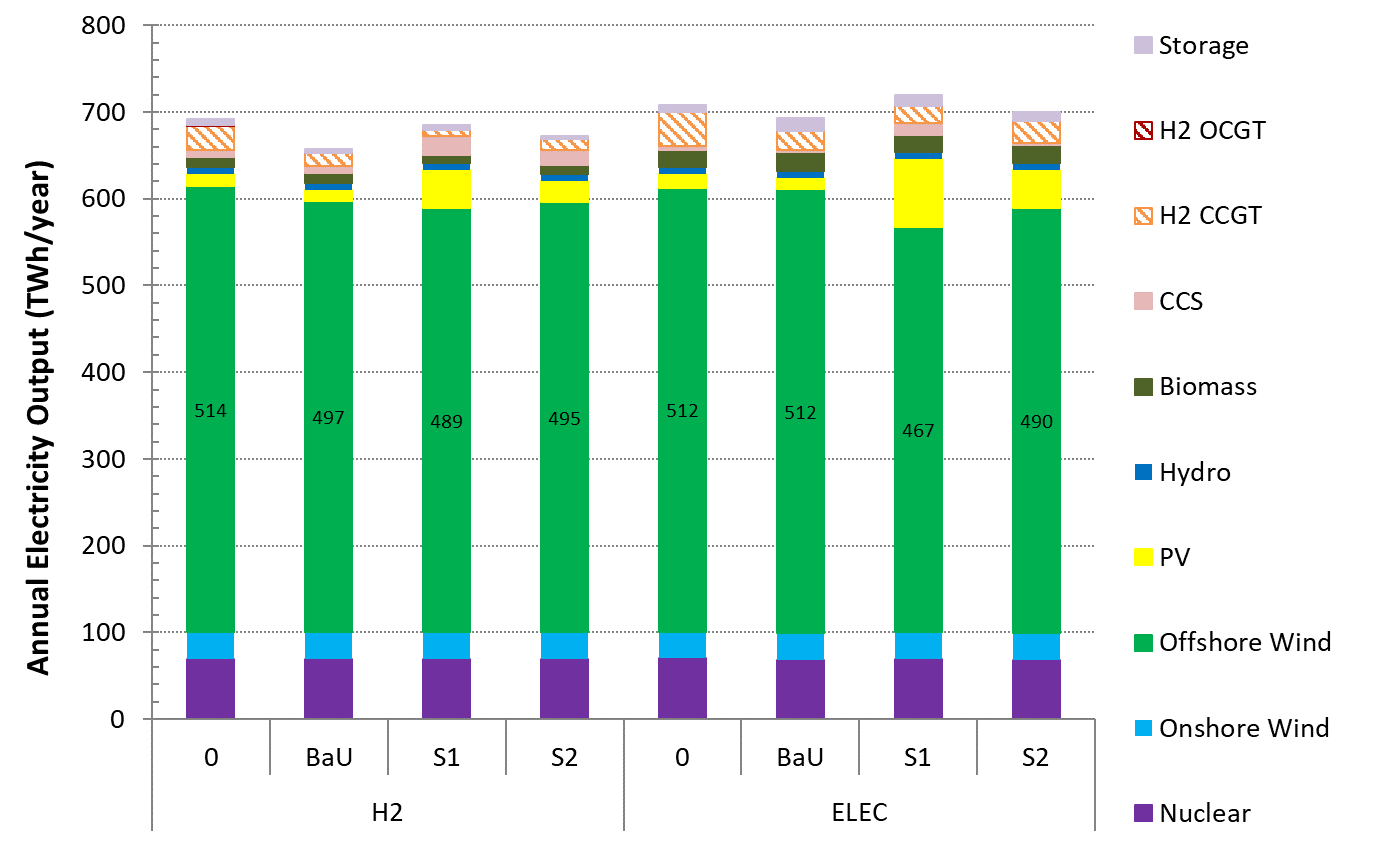


Figure 2‑7 Impact of different coordination schemes on optimal electricity production

Consistent with the previous findings, distributed flexibility resources substitute flexibility provided by hydrogen CCGT, reducing the electricity production from that generation. Coordinating the dispatches of those technologies through market mechanisms may become a challenge that should be addressed in the subsequent Workstream.

## Impact of different coordination schemes on optimal distributed flexibility resources

Different coordination schemes will also lead to different portfolios of distributed flexibility sources. Figure 2‑8 shows different cases' optimal portfolios of distributed flexibility resources. From electricity demand response technologies, the largest source comes from smart electric vehicle charging; some of them could be vehicle-to-grid technology. It allows the electric vehicle's battery to inject the power back into the grid to provide balancing or ancillary services.

Other demand response technologies include smart appliances and flexibility services from industrial and commercial customers. Another technology is distributed electricity storage and thermal storage. As thermal storage costs are quite low compared to other technologies, increasing thermal storage will be beneficial as it allows shifting the electric heating loads to consume during low-cost electricity periods.

In the H2 scenario, most distributed flexibility resources are demand response technologies compared to electricity storage. However, this ratio changes in the deep electrification scenario where the ratio of electricity storage and demand response technologies can be around 1:1 (e.g. in Scheme 1, ELEC). Up to 53 GW of electricity storage will be needed in S1, around 75% higher than in BaU and S2, due to the need to minimise distribution network reinforcement.

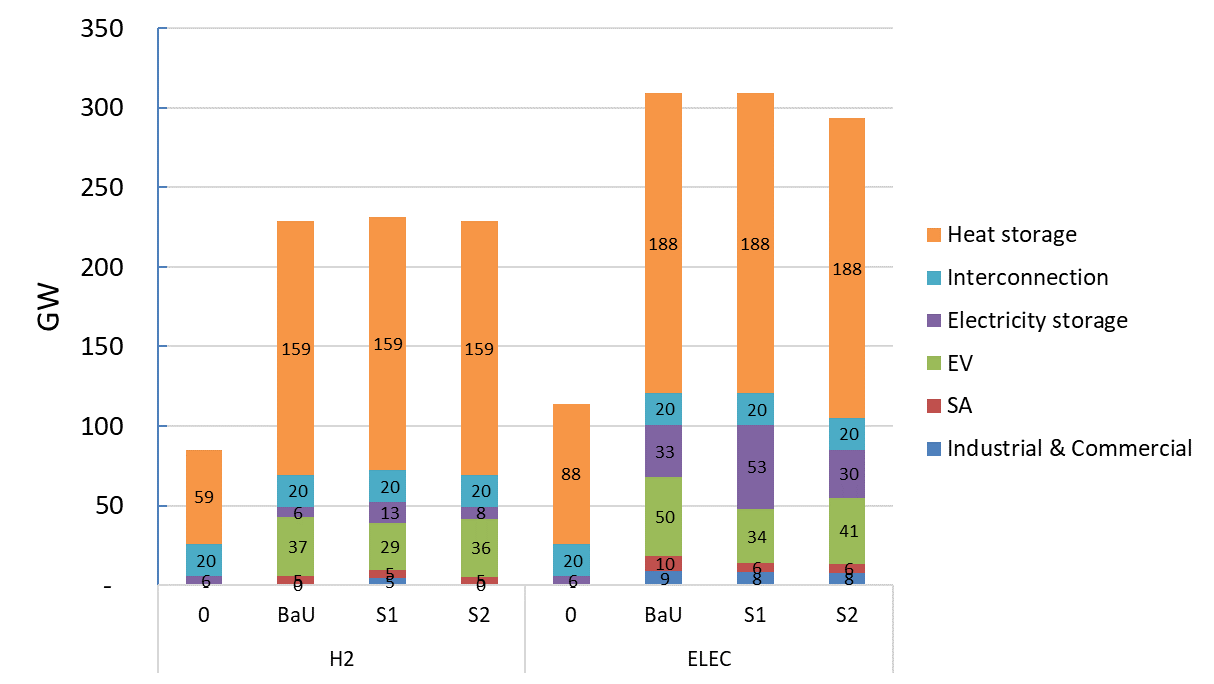


Figure 2‑8 Impact of different coordination schemes on optimal distributed flexibility resources

The studies demonstrate *a substantial volume (50 – 100 GW) of demand response and electricity storage in addition to tens of GW of smart heat-led electricity load that must be managed and utilised efficiently to maximise their benefits to local and national energy systems*. This aspect highlights the need for strong ESO-DSO coordination and appropriate market frameworks to facilitate the cost-effective management of those resources. The total capacity of demand response and electricity storage volume is double in the deep electrification scenario than in H2, driven by a higher system benefit of distributed flexibility resources in ELEC than in H2.

### Regional distribution of energy storage and demand response capability

In general, the electricity storage would be optimally deployed across the system though the magnitude should be optimised from the system needs considering the geographical spread of different power generation technologies, regional loads, and transmission network capacity. In the hydrogen scenario, most electricity storage should be allocated to the Northern GB. In the deep electrification scenario, electricity storage distribution is more balanced across the North (North of England and Scotland) against the rest (Midlands, South and Wales) except in Scheme 1, where significant electricity storage (32 GW out of 53 GW) is allocated in the North. The locations of storage are driven by the locations of high capacity factors offshore wind farms in the North.

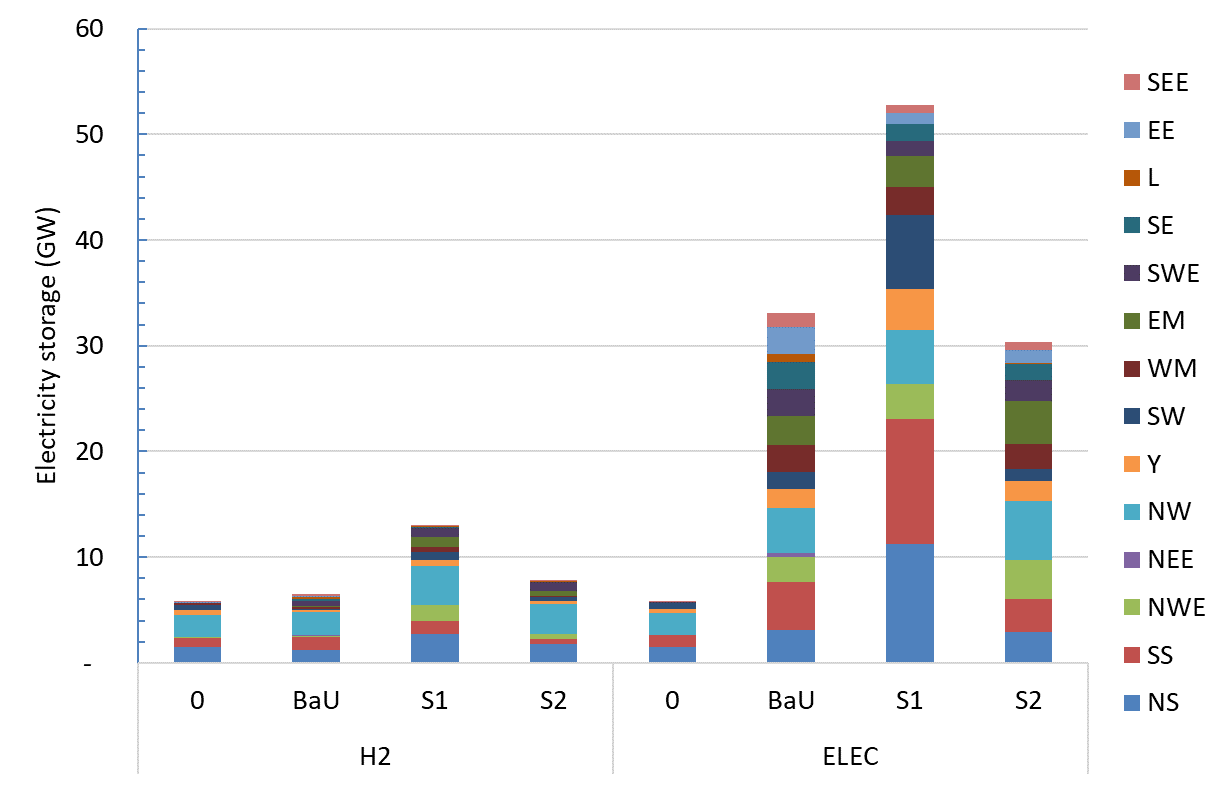


Figure 2‑9 Regional distribution of electricity storage capacity

Demand response capacity should also be deployed, like electricity storage, across the system. Figure 2‑10 shows the modelling results of the regional deployment of demand response flexibility services. Considering that the available demand response is a function of the energy demand, the demand response capacity is distributed more proportionally to the demand size in this area. It is worth noting that ESO and DSO must manage a substantial volume of demand response, i.e. around 40 GW in H2 and between 46 – 66 GW in ELEC. BaU requires more demand response capability, followed by Schemes 2 and 1. While how this could be achieved in practice is out of the scope of this work, it gives an insight into the scale of the demand flexibility that must be dealt with in future.

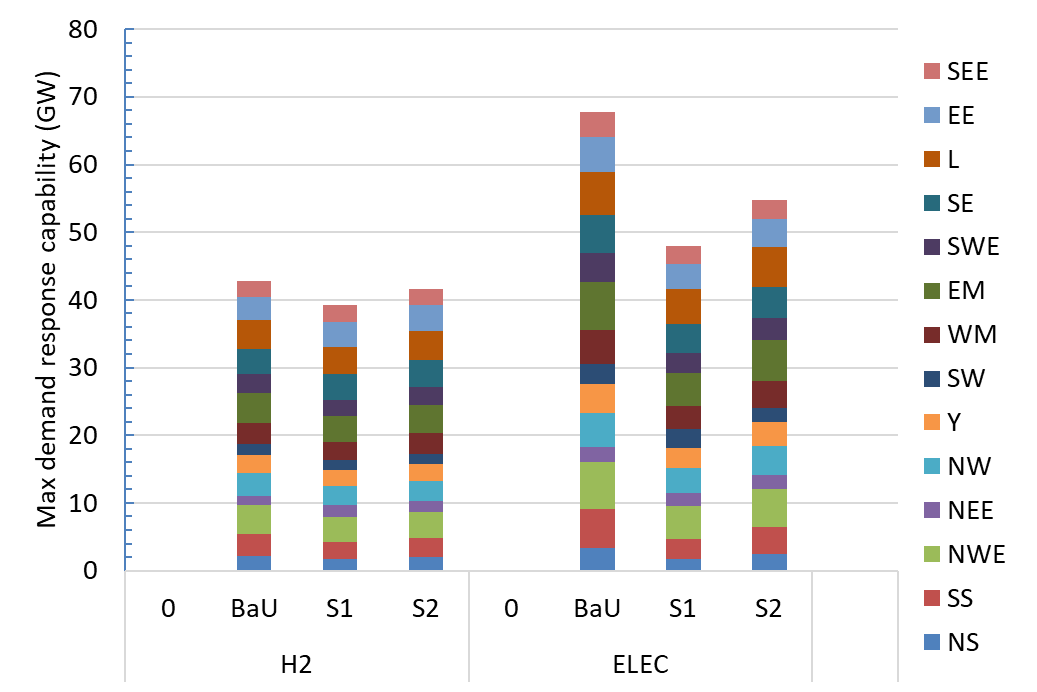


Figure 2‑10 Regional distribution of demand response capability

## Incremental costs of suboptimality that may occur in Scheme 1

The coordination between ESO and DSO in Scheme 1 is prone to be suboptimal in practice due to:

* The lack of ability of ESO to incorporate small-scale distributed flexibility providers, which leads the ESO to prioritise larger-scale sources, e.g. connected at high voltage rather than small-scale low-voltage connected resources;
* Exposure of stricter primacy rules to DSOs to provide sufficient headroom to deal with uncertainty in the provision of services and distribution network capacity to accommodate that;
* Higher cost of distributed flexibility services – we assume the cost could increase up to 20%;
* A lower number of service providers – we assume only 75% of potential distributed flexibility sources could be accessed.

The study aims to assess quantitatively the impact of the suboptimality, if it happens, on the system costs. The incremental costs associated with each suboptimality are shown in Figure 2‑12. The last column shows the additional costs if all suboptimality conditions occur. The annual system costs of Scheme 1 are, therefore, in the range of 87.64 – 91.92 £bn/year. The study uses the deep electrification scenario as the difference between Scheme 1 and 2 is more visible than in the H2 scenario.

The most important factor that increases the total annual system cost is the inability of ESO to incorporate services from small-scale providers through aggregators. It will cost £2.9bn/year to the system as substantial flexibility could be provided by low-voltage connected customers. The second factor is the exposure to stricter primacy rules through providing extra distribution capacity headroom and over-procurement of services to deal with uncertainty in the deliverability of the flexible services due to various reasons (e.g. network constraints, temporal unavailability of some service providers). The impact of the higher cost of distributed flexibility services and lower availability is not high as the cost of flexibility services is very small compared to the total system cost. Using all potential maximum flexibility resources is unnecessary, as the maximum volume of demand response and energy storage is sufficiently large. Having 75% of them is sufficient to meet the system's needs; therefore, the impact on cost is modest. Combining all suboptimality conditions will increase the total system cost by £4.28bn/year, similar to the sum of all incremental costs of each suboptimality condition being studied.

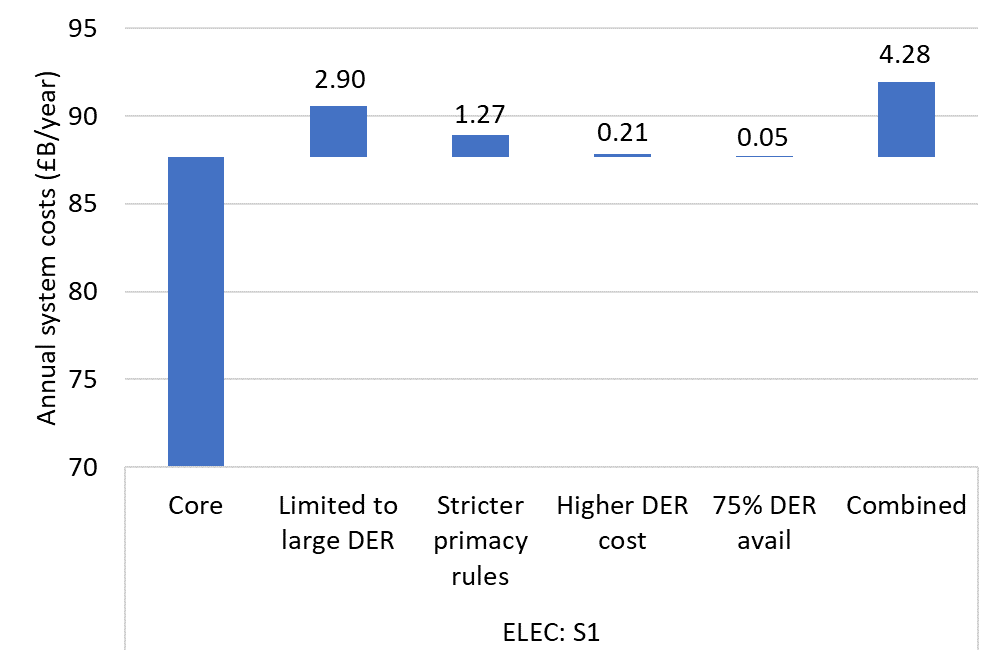


Figure 2‑12 Incremental costs associated with the suboptimality possibly occurred in scheme 1

Perhaps some words here around what the options/way forward may be to enable visibility of DER’s etc. it would be good to point to the fact that the worlds will help some of the challenges above.

# Sensitivity studies

The results of techno-economic studies discussed in the previous section may be sensitive to different conditions. Therefore, it is important to investigate whether the findings found previously are changed or consistent if different system conditions are used in the studies. Therefore, various sensitivity studies have been conducted to understand the previous findings' robustness and identify the main drivers for improving the ESO-DSO coordination approach.

## Sensitivity scenarios

In that context, we performed sensitivity studies to assess the impact of having the following parameters:

* A higher energy demand – this is achieved by increasing the domestic heat demand from 222 TWh/year (based on FES 2022 "Leading the Way") to 277 TWh/year (based on FES 2022 "System Transformation").
* A higher cost distributed flexibility resources – the cost of demand response technologies and energy storage is increased by 20% in the high-cost scenario.
* A 10% higher distribution network cost
* A lower levelised cost of wind generation – this study aims to increase wind penetration in the system and therefore increases the system flexibility requirements.
* Lack of demand response services may trigger other distributed flexibility technologies, such as energy storage, and may affect the need for stronger ESO and DSO coordination.

The altered parameters in the sensitivity studies are compared with those in the core scenarios. The comparison of those parameters is shown in Table 3‑1.

Table 3‑1 List of sensitivity study scenarios being studied

|  |  |  |
| --- | --- | --- |
| **Factors** | **Core** | **Sensitivity** |
| Level of domestic heat demand (TWh/year) | 222 (Leading the Way) | 277 (System transformation) |
| Cost of distributed flexibility resources | Low-cost scenario | High-cost scenario (+20%) |
| Cost of distribution network | Central | High (+10%) |
| Cost of wind | £35/MWh | £25/MWh |
| Demand side flexibility | Yes (Consumer Transformation and Leading the Way) | No (System transformation) |

## System benefits of Scheme 1 (Enhanced Coordination) and Scheme 2 (Distributed Flexibility Coordinator) against Business-as-Usual approach

The system benefits of improving ESO-DSO coordination by moving from BaU to Scheme 1 and Scheme 2 are derived by calculating the difference between the annual system costs of those scenarios under different system conditions as defined in Table 3‑1. The results for Scheme 1 and 2 are shown in Figure 3‑1 and Figure 3‑2, respectively.

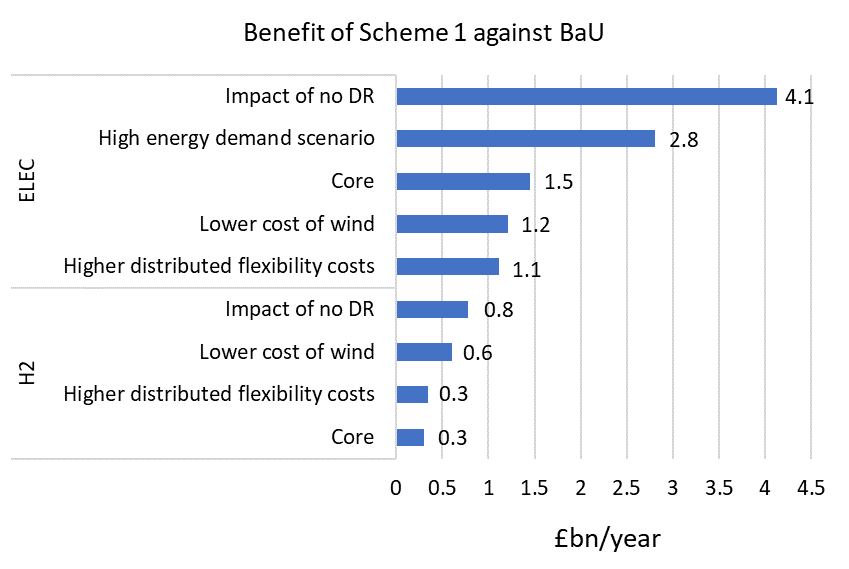


Figure 3‑1 System benefits of Scheme 1 (Enhanced ESO-DSO coordination) against the Business-as-Usual approach

Figure 3‑2 System benefits of Scheme 2 (Enhanced ESO-DSO coordination) against the Business-as-Usual approach

The modelling results of the sensitivity studies demonstrate the following:

* Improving the ESO-DSO coordination approach from the BaU to Scheme 1 and 2 will reduce the cost of the future system by 0.3 – 0.9 £bn/year in the hydrogen scenario and 1.1 – 4.3 £bn/year in the deep electrification scenario.
* While the cost of improving the coordination has not been considered, the cost is likely to be lower than the benefits. Further detailed studies are recommended to understand what needs to be provided to enable such coordination and the associated costs.
* If the future system is moving towards full electrification of heat and transport, the case for improving ESO-DSO coordination would be stronger than the one with hydrogen heating.
* The benefits of Schemes 1 and 2 are also higher in the system with higher energy demand and without demand response. Without demand response, the amount of electricity storage needed in the system to provide flexibility increases substantially, and most of them will be located at distribution as it can also be used to manage distribution network constraints. Hence, this increased distributed electricity storage will also increase ESO and DSO's operational challenges; therefore, stronger coordination will be needed.
* Other conditions, such as the lower cost of wind, may also increase the need for coordination but not always occur in all cases we simulated. As wind is already very dominant in the core scenarios, increasing more wind due to its lower cost will not affect the system performance so much and the need for flexibility.
* Higher distributed flexibility costs may reduce the case for improving coordination slightly, but the impact is marginal, and the savings are still positive.

# Use Cases

## Objective

We have defined a range of use cases that will be used, in Workstream 3, to analyse and benchmark the performance of Scheme 1 and Scheme 2. The use cases consider the worst case scenarios for the operation of the networks, adequately applied to prototype networks. For each of the use cases, we will associate a stressed situation with an illustrative example of a dummy network diagram, reflecting a network location where the stressed situation would be particulary serious. For each use case, we will define the situation, summarise the expected impact and briefly discuss the required flexibility services by DERs.

## Definition of stressed situations

We have identified specific operational use cases, with a focus on stressed situations for network operation and where coordination ESO-DSO will be essential. These are aligned with the scenarios mentioned above. The stressed situations that we considered were:

* High offshore wind energy generation
* High heat pump consumption
* High demand for transport
* High embedded generation, namely solar PV

### High offshore wind energy generation

Offshore wind will play a critical role in UK energy system transition to Net Zero. The UK Government target for wind offshore installed capacity in 2030 is 50 GW[[3]](#footnote-4). In line with the ESO Future Energy Scenarios ("FES"), we assume an offshore wind installed capacity of 95GW by 2050, as considered in the System Transformation scenario[[4]](#footnote-5). The high amount of wind energy will require a high level of flexibility at both distribution and transmission level. This is due to the intermittent pattern of wind energy: as peak generation may occur at times of low demand (week days overnight, weekends), there will be a significant need for storing the surplus of wind energy generated or exporting it via interconnections with neighbouring countries.

### High heat pump consumption (likely over Winter Peak)

4 in 5 homes will be using a primary heat source other than a natural gas boiler by 2045, according to all FES except Falling Short. The wider electrification of heat, as seen before in Chapter 3, will increase the electricity peak demand, as forecasted in the FES. This network situation will be exacerbated namely over evening peaks at Winter, when renewable generation at Distribution level will be limited. These periods are likely to require a significant amount of long duration flexibility, over hours or even days, assuming a lower level of renewable energy generation.

### High demand for transport

With high penetration of Electric Vehicles (EVs) due to growing needs for electrification of transport, there is a likely increase in EVs demand, particularly in the mornings and evenings. The EV demand spikes could impact electricity network at both national and distribution levels.

At the national level, the peak demand could occur during cloudy winter days with low wind production or loss of sunshine together with peak demand in the evening. At the distribution level, EV peak demand in individual areas could be uneven due to personal EVs penetration levels. Distribution network in certain areas might experience significant overloading, particularly during peak demand in the evenings.

Potential national mitigation solutions could be utilising battery storage to harness the surplus of high solar generation during the day and discharge it during the evenings to smooth the output of traditional power generations. At the distribution level, battery storage can also be used to shave EV charging peaks. Other potential non-wire mitigations could be investment in smart power flow management devices, coordination/flexible with Distribution Energy Resources (DERs), limit charging rating, delay charging and increase distribution generation. The wire solutions such as upgrading transformer and feeder capacity and connection to higher voltage could help.

### High embedded generation (solar PV)

High penetration of embedded generations/DERs might impact both distribution and transmission networks. The impact could be on losses, voltage profile, fault level and distribution transformer and feeder capacity. In a moderate to high DERs output, transmission lines could be lightly overloaded and that could increase voltage level at the transmission network. Combined with high wind and solar generation output connected to transmission network, it could cause generation surplus which could be absorbed by battery storage or exported through interconnectors.

Considering the worst case scenario, there could be a significant reverse power flow across distribution networks which requires both non-wire and wire solutions to manage flow and mitigate the impact on the system. Additionally, the embedded generation output could be uneven because of different levels of penetration across the network.

## Definition of use cases

Building on the stressed situations mentioned above, we will consider the priority use cases that were investigated in the ENA Open Networks Programme. The use cases that will be investigated in our work include:

* 1. STOR (ESO) and generation-led ANM (DSO) on different assets in the same area;
  2. Transmission constraint management service (ESO) and DNO services (DSO) on different assets in the same area;
  3. The BM and generation-led ANM on different assets in the same area;

Given the increase of intermittent renewable generation and thus the importance of the capacity market, we will also consider

* 1. Capacity Market and generation-led ANM on different assets in the same area

During Workstream 3 we will be assessing the impact of Scheme 1 and Scheme 2 in specific use cases, under a specific stressed situation. This will provide both the local and the national impact of each coordination Scheme. We will utilise a network model with two Distribution substations (DS) and three Transmission substations (TS), including a Grid Supply Point (GSP). We will identify the key players and required information exchanges across the roles and responsibilities of the access to DFR (Qualification, Procurement, Dispatch, Settlement and Compliance, as shown in Workstream 1 report Section 6.2.2.), verify information exchanges (as shown above) and specify the main technical variables to serve as an example (e.g. active power, type of constraint, indicative prices).

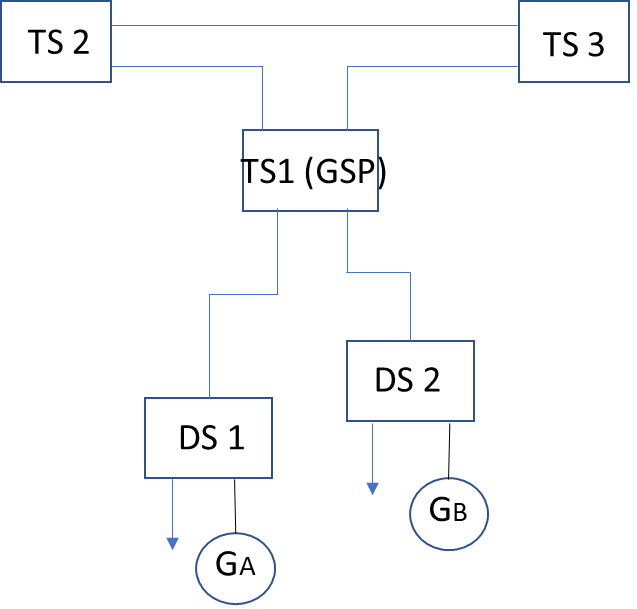


Figure 33: Illustrative Network Model

# Conclusions

A range of case studies has been analysed to analyse the techno-economic performance of different ESO-DSO coordination approaches, focusing on the 2050 net zero-emission system to ensure the effectiveness of the approaches on future sustainable energy systems. Flexibility from all technologies, including sector-coupling flexibility in electricity, gas and heating/cooling systems, has been considered. The key findings can be summarized as follows:

**Distributed flexibility should be facilitated to minimise the system costs**

* Harnessing and utilising distributed flexibility resources saves the annual system costs between 7.4- 7.8 £bn/year in H2 and 9-11.3 £bn/year in ELEC.
* Electrification is one of the major drivers for utilising distributed flexibility resources. Therefore, the benefits of distributed flexibility are higher in deep electrification. Therefore, it requires a more holistic approach to coordinating distributed flexibility resources. It is worth noting that electrification occurs in both hydrogen and deep electrification pathways in different magnitudes; hence, deploying distributed flexibility resources is relevant in both scenarios.
* The savings can be achieved if there is some investment in flexibility sources such as heat storage, electricity storage, and demand response technologies. Given the cost assumptions used in the study, the cost of procuring and utilising distributed flexibility is much lower than its benefits.
* The main savings attributed to distributed flexibility are in the mitigation cost of investment in low-carbon power generation and distribution networks. Customers' flexibility also reduces end-users' appliance costs, such as heat pumps. Heat storage can reduce the size of heat pumps needed. Moreover, the savings happen not only in the electricity sector but also in other system costs, such as the reduced investment needed in electrolysers and hydrogen storage.

**Benefits of improving ESO – DSO coordination schemes**

* Improving the ESO-DSO coordination approach from the BaU to Scheme 1 and 2 will reduce the cost of the future system by 0.3 – 0.9 £bn/year in the hydrogen scenario and 1.1 – 4.3 £bn/year in the deep electrification scenario. If the future system is moving towards full electrification of heat and transport, the case for improving ESO-DSO coordination would be stronger than the one with hydrogen heating. The performance of Scheme 1 and 2 would be relatively similar if all the coordination processes could be carried out smoothly. However, Scheme 1 may pose a higher risk for suboptimal conditions such as a lack of ESO's ability to incorporate small-scale DFR providers to its control centre, exposure of stricter primacy rules to DSOs to provide sufficient headroom to deal with uncertainty in the provision of services and network capacity, higher cost of DFRs and lower number of service providers due to lack of market competition and transparency. These suboptimality conditions may increase the system costs by up to £4.28bn/year. Therefore, Scheme 2 could be an option to derisk these conditions.
* While the cost of improving the coordination has not been considered, the cost is likely to be lower than the benefits. Further detailed studies are recommended to understand what needs to be provided to enable such coordination and the associated costs.
* Different coordination schemes will affect the energy system's investment and operational costs. The impacts are beyond the electrical transmission and distribution systems; therefore, it is crucial to decide carefully as it has long-term effects.
* The benefits of Schemes 1 and 2 are also higher in the FES 2022 "System Transformation" scenario (note: the core scenario used in the study is based on "Leading the Way"), which has a higher energy demand and without demand response. Without demand response, the amount of electricity storage needed in the system to provide flexibility increases substantially, and most of them will be located at distribution as it can also be used to manage distribution network constraints. Hence, this increased distributed electricity storage will also increase ESO and DSO's operational challenges; therefore, stronger coordination will be needed.
* Other conditions, such as the lower cost of wind, may also increase the need for coordination but not always occur in all cases we simulated. As the wind is already very dominant in the core scenarios, increasing slightly more wind due to its lower cost will not affect the system performance so much and the need for flexibility.
* Higher distributed flexibility costs may slightly reduce the case for improving coordination, but the impact is marginal, and the savings are still positive.

The studies also demonstrate that DFRs will be distributed across the GB system. Higher penetration of electricity storage can occur in the Northern GB due to high capacity factors of offshore wind in those areas but in general, both energy storage and demand response technologies will be spread across the GB. Therefore, ESO – DSO coordination will be required across the GB system.

## Next steps

In Workstream 3, we will run a qualitative and quantative impact assessment of Schemes 1 and 2 performances in stressed situations for the network, namely:

* Develop a wide-ranging criteria to underpin the qualitative impact assessment. The criteria may cover the strategic case, commercial case, financial case, etc. including aspects such as customer experience, market viability sustainability, environmental sustainability, regulatory frameworks, industry structure and organisation, etc.
* Execute the qualitative impact assessment and conduct stakeholder engagement activities within the ESO to support with scoring across the criteria;
* Enhance the current whole electricity system model to represent the developed ESO/DSO coordination schemes at planning timescales;
* Quantitative assessment (i.e. economic case criterion) of the relative costs and benefits for the impact assessment. Application of the model to quantify and assess the different ESO/DSO coordination schemes against the costs incurred from investing in traditional electricity infrastructure and balancing the whole electricity system and the benefits brough by flexibility energy resources;
* Combine the quantitative and qualitative assessments to form the overall impact assessment. Select the preferred ESO/DSO coordination scheme for roadmap development.

1. Energy system background and key assumptions

The data below are intended for the 2050 system studies. Most of the data are taken from established studies, including:

1. CCC studies (2018) – "Analysis of Alternative UK Heat Decarbonisation Pathways", available at: <https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf>
2. Carbon Trust (2021) – Flexibility in GB, available at: <https://publications.carbontrust.com/flex-gb/analysis/>
3. National Grid ESO (2022) – <https://www.nationalgrideso.com/future-energy/future-energy-scenarios>

Data from the above studies were usually the results of consultations with key industry stakeholders, CCC, BEIS and research organisations.

The key input data and assumptions are summarised in the following table.

| Category | Key input data and assumptions for central scenarios |
| --- | --- |
| Carbon emissions | Net-zero on an annual basis (GB system)  Need to offset emissions from "hard to decarbonise" sectors: 50 MtCO2/year  Include emissions from electricity and hydrogen systems |
| Energy demand | All figures are in TWh/year\*  7% losses are included in the electricity demand to account for transmission and distribution losses.  Domestic   * heat demand: 228 TWh (heat) [[5]](#footnote-6) * appliances: 48 TWh (electricity)   Road transport: 123 TWh (electricity)  HGV, shipping, aviation, non-heat industrial hydrogen process: 88 TWh (hydrogen)  Non-domestic   * electricity (non-transport/heat): 224 TWh * space and water heating: 81 TWh (heat) * industry low-temperature heating: 57 TWh (heat) * industry high-temperature heating: 37 TWh (hydrogen)   Cooling (electricity): 12 TWh (electricity)  Electricity demand from electrolysis, hydrogen production, energy storage, DACCS, and interconnectors is excluded in this table. Those will be calculated in the model directly.  The energy system infrastructure and operation in IWES are optimised to meet the annual energy demand and net-zero emissions requirements. The GB is assumed to be energy positive at the annual level (total annual demand is less or equal to annual production), and the interconnectors are used for short-term energy/power exchanges with adjacent countries. |
| Bioenergy | 151 TWh (biomass input) |
| Negative emission technologies | BECCS for power, hydrogen, methane  DACCS with electricity and hydrogen heating |
| CCUS | Carbon storage and CCUS network are available and optimised by the model  Cost of storing carbon: £15/tCO2  All CCUS technologies (except BECCS) are developed in regions with carbon storage terminals (Scotland, North East England, North Wales, East Midlands, East England) |
| LCoE of power generation in 2050 | Renewable and nuclear technologies   |  |  |  | | --- | --- | --- | | **Technology** | **LCOE (£/MWh)** | **Max. capacity by 2050 (GW)\*** | | Offshore | 35 | 110 | | Onshore | 30 | 50 | | Solar PV | 44 | 100 | | Nuclear | 60 | 20 |   \*rounding up to the nearest 10GW from FES 2022 capacity  Other technologies   |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | | **Technology** | **CAPEX £/kW (2050)** | **Fixed Cost (£/kW) (2050)** | **Hurdle rate** | **Lifetime** | **Annuitised cost (£/kW p.a.)** | | H2 CCGT | 611 | 31 | 7.50% | 25 | 82.44 | | H2 OCGT | 578 | 31 | 7.50% | 25 | 79.73 | | Gas CCS - CCGT | 1,203 | 61 | 13.80% | 25 | 212.39 | | Nuclear - Large | 3,870 | 78 | 9.50% | 40 | 423.29 | | Biomass with CCS | 3,308 | 33 | 10% | 25 | 364.67 |   No unabated natural gas-fired power generation in 2050 |
| Electricity interconnectors to Europe | Baseline capacity: 11.7 GW   |  |  | | --- | --- | | Countries | GW | | France | 5.4 | | Ireland | 1.5 | | Netherlands | 1 | | Norway | 1.4 | | Belgium | 1 | | Denmark | 1.4 |   The Maximum additional capacity that can be built by 2050 is 8.3 GW bringing the maximum potential capacity to 20 GW. |
| Distributed storage | Technology: Li-Ion (grid scale >50MW). CAPEX: £55/kWh (in 2050). WACC:6.5%, Lifetime: 10 years |
| Heat decarbonisation | Few possible pathways for on-gas-grid customers:   1. Electrification (a combination between ASHP and resistive heating) 2. Hydrogen boiler   District heating networks (DHNs) supply 20% of heat demand.  DHNs are in urban areas only and supplied by G/WSHP with a flat COP (3).  The heat demand of off-gas-grid customers is supplied by electric heating.  ASHP needs at least 2kWh thermal storage. DHN storage is around 20kWh/household.  The model optimises additional thermal storage. |
| Hydrogen technologies | Three main hydrogen production technologies:   * Auto Thermal Reformers with CCUS * Electrolysis (Proton Exchange Membrane, Alkaline, and Solid Oxide) * BECCS (gasification)     Unless otherwise stated, the study also assumes that hydrogen production in the GB should be sufficient to meet the hydrogen demand. |
| Hydrogen storage | Two technologies:   * Underground storage (Cheshire Basin, East Yorkshire, East Irish Sea and Wessex) * Overground storage – around 350 GWh distributed storage is needed to enable meeting hydrogen peak demand |
| Hydrogen network | The natural gas National Transmission System will be repurposed and hydrogen compatible.  Gas distribution will be hydrogen compatible in 2050 |
| Gas price | £23.67/MWh |
| Demand flexibility | Maximum potential flexibility:   * 20% of Industrial and Commercial customers * 40% of smart appliances * 80% of smart EV   Heat storage is used to modulate the heat-led electricity demand.  Flexibility services include load-shifting for arbitrage, capacity, network congestion, and ancillary services (frequency response and reserves) |
| Optimisation approach | Whole-system approach – all system components are optimised to reduce the system costs. |
| Distribution network cost | The cost function is derived using representative fractal networks considering GB distribution network characteristics for urban and rural systems with different customer densities. 14 DNO regions are modelled. |

1. Modelling approach

To study the interaction between multi-energy vectors and analyse the impacts of alternative decarbonisation strategies on the UK energy infrastructure in 2050, a range of scenarios can be simulated and optimised using Imperial's Integrated Whole-Energy System (IWES) model. The IWES model incorporates detailed modelling of the electricity system and heating options, including district heating, heat network, heat pumps (air/ground source, Hybrid), and hydrogen infrastructure. IWES models the complex interactions across those energy vectors, as shown in Figure B- 1.

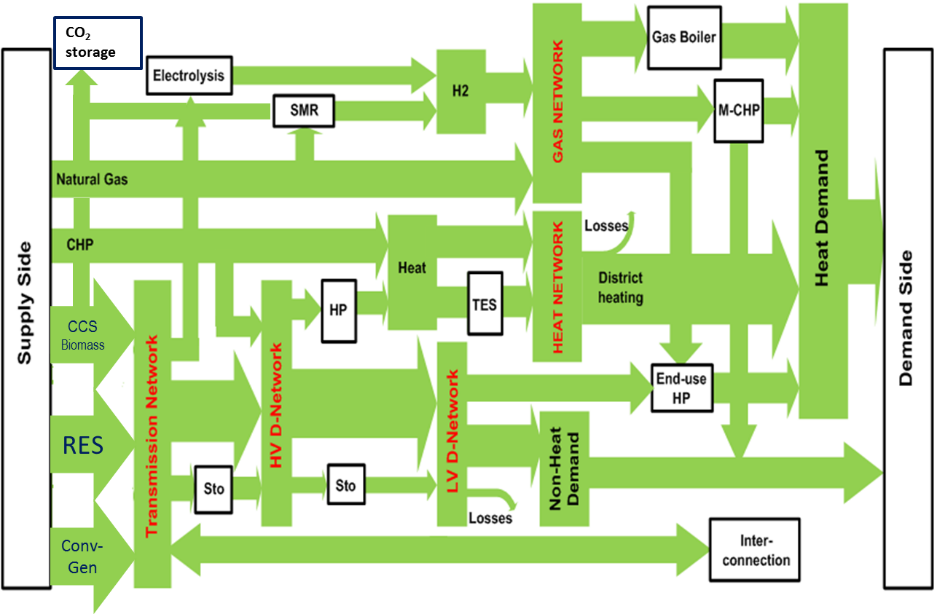


Figure B- 1 Interaction between gas, heat, and electricity systems

In IWES, the multi-energy system's short-term operation and long-term investment decisions are optimised simultaneously to minimise the overall system costs by maximising synergies in system expansion planning and operation within agreed constraints, such as a specified carbon target. The model covers both local district and national/international level energy infrastructure details, including energy-flow interactions with mainland Europe via interconnectors, as illustrated in Figure B- 2. This functionality is essential since those aspects are complexly intertwined and must be analysed simultaneously in the whole-energy system context.

The GB energy system is divided into 14 regions following the distribution network areas to provide sufficient spatial granularity to capture the regional characteristics. Each region has two (or more) different representative district characteristics (e.g. urban and rural systems). IWES also considers the interactions between the GB energy system, Ireland, and continental Europe, cross-border energy exchange, and sharing capacity and flexibility.

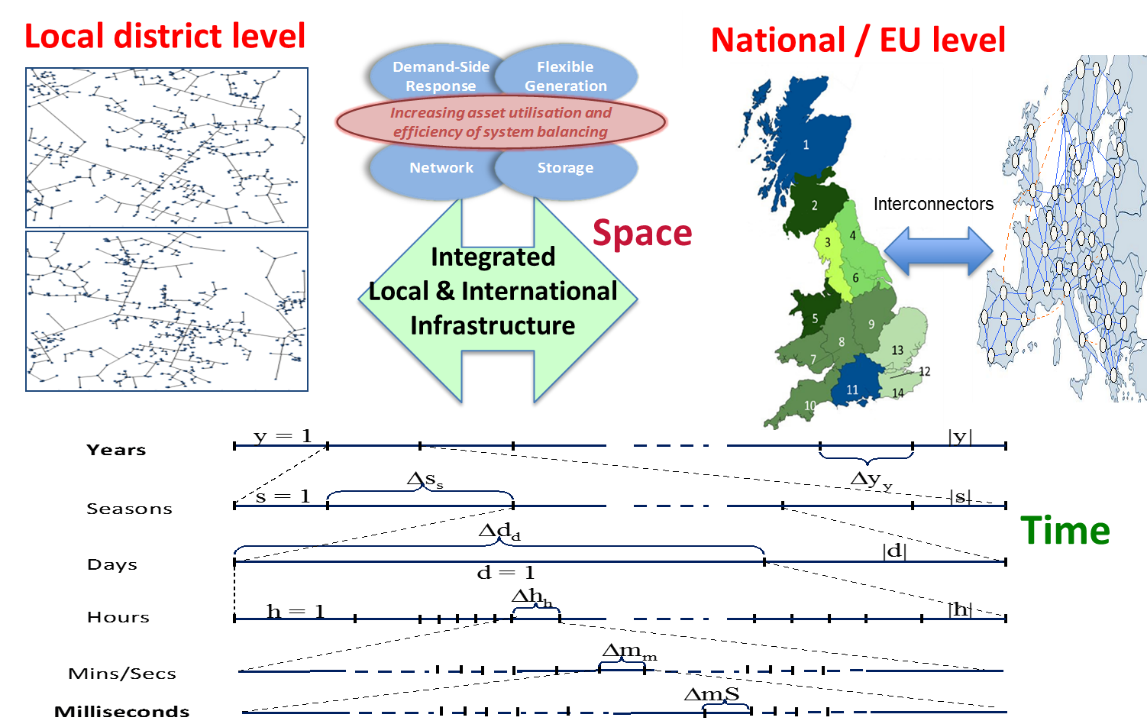


Figure B- 2 Coordinated decisions across various timeframes and location interactions in the integrated modelling of low-carbon systems

IWES optimises the energy supply portfolio, transmission and distribution infrastructure, and energy storage simultaneously to capture system components' interactions. For example, a more extensive distribution capacity may be needed to enable end-users' flexibility to follow renewable output. IWES also optimises the technical needs for real-time supply and demand balancing, including frequency regulation and balancing reserve (seconds and minutes timescale) while considering critically essential changes in the system inertia (which is vital for zero-carbon energy system) while reflecting on the dynamic parameters and technical limitations of the selected portfolio of energy sources and flexibility technologies. The benefits of system flexibility provision can be analysed across various energy vectors.

IWES model has been applied to investigate the value of system flexibility[[6]](#footnote-7), evaluate the performance and system implications of different heat decarbonisation pathways[[7]](#footnote-8), quantify the benefits of hydrogen and electricity integration involving electrolysers and hydrogen-fuelled power generation, identify the role of carbon removal technology for net-zero, understand the impact of local versus whole-system optimisation and the importance of ESO-DSO coordination, identify the system integration cost of renewables[[8]](#footnote-9), and the value of long-duration energy storage[[9]](#footnote-10).

The IWES model considers more than 30 different cost categories. However, for simplicity, the annual system costs are presented and grouped into fewer high-level cost categories, including eleven Capital expenditure (C), two Operating costs (O) and one Revenue (R) categories described as follows:

Table B-1 Detailed and higher-level cost categories

| Detailed cost category | Higher-level cost mapping | Description (all capital costs are annuitized[[10]](#footnote-11) , and operating costs are annual) |
| --- | --- | --- |
| C: Low carbon gen | C: Electricity  generation | Capital cost of wind, PV, hydro, nuclear, gas CCS, power BECCS, and H2-based generation. |
| C: Non-low-carbon  gen | C: Electricity  generation | Capital cost of traditional fossil-fuel-based generation such as CCGT, OCGT and CHP |
| C: Transmission | C: Transmission and interconnection | Capital cost of the GB transmission network, including onshore and offshore (but not interconnection) |
| C: Interconnection | C: Transmission and interconnection | Capital cost of GB interconnectors |
| C: Distribution | C: Distribution  networks | Capital cost of reinforcing electricity distribution network |
| O: Electricity | O: Electricity | Fuel cost, no-load cost and start-up cost of power generation. The cost of hydrogen as a fuel is excluded here[[11]](#footnote-12) but included in the Capex and Opex of hydrogen. |
| C: HP | C: Electric heating | Capital cost of heat pump devices, installation cost and the annual fixed operating and maintenance cost |
| C: RH | C: Electric heating | Capital cost of resistive heating devices, installation cost and the annual fixed operating and maintenance cost. RH is not used in this study but is part of the IWES model. |
| C: Storage | C: Electricity and thermal storage | Capital cost of electricity storage in the system; it includes the cost of pumped hydro and battery energy storage system |
| C: Heat storage | C: Electricity and thermal storage | Capital cost of domestic and district heating thermal energy storage |
| C: DACCS | C: Hydrogen and CCS | Capital cost of DACCS[[12]](#footnote-13) |
| C: Decom. gas  distribution | C: Electric heating | this cost occurs only in the Electric scenario as most of the gas distribution network is no longer used, and therefore, it should be decommissioned. The cost is estimated at £1bn/year. A small proportion of gas distribution connected to large customers (e.g. industry) and BECCS to hydrogen is maintained. |
| C: ATR+Bio | C: Hydrogen and CCS | Capital cost of building ATR with CCS and the biomass gasification with CCS for hydrogen production |
| C: Electrolysis | C: Hydrogen and CCS | Capital cost of various electrolysers: Proton Exchange Membrane (PEM), Alkaline, Solid Oxide Electrolyser (SOE) |
| C: H2 network | C: Hydrogen and CCS | Capital cost of building a national hydrogen transmission network. It is assumed that the national gas transmission is retained. |
| C:H2 storage | C: Hydrogen and CCS | Capital cost of both underground and overground storage |
| C: CCS network | C: Hydrogen and CCS | Capital cost of building the CCS network |
| C: Carbon storage | C: Hydrogen and CCS | Cost of storing carbon captured by CCS. It is assumed that the carbon storage cost is £15/tCO2. |
| O: ATR+Bio | O: Hydrogen and CCS | Fuel cost used by ATR with CCS and BECCS to produce hydrogen[[13]](#footnote-14) |
| O:H2 storage | O: Hydrogen and CCS | Operating cost of hydrogen storage |
| O: NG boiler | O: Hydrogen and CCS | Cost of natural gas used by the boilers |
| C: NG boiler | C: Gas heating | Cost of natural-gas-based boilers, installation, and the annual fixed operating and maintenance costs |
| C: H2 boiler | C: Gas heating | Cost of hydrogen-based boilers, installation, and the annual fixed operating and maintenance costs |
| C: Gas network | C: Gas heating | Cost of retaining the present gas distribution network. It is applied to the H2 and Hybrid pathways. |
| C: DH (network) | C: District heating | Cost of district heating networks, including the operating and maintenance cost |
| C:DH (appliance) | C: District heating | Cost of household heat infrastructure needed for the district heating system, e.g. metering, heat control, and connection to the main heat network |
| C:DH (conversion) | C: District heating | Cost of decommissioning natural-gas appliances including replacing the gas hob and gas oven with an electric hob and oven and adding the hot-water storage system |
| C: HHP | C: HHP heating | Capital cost of heat pump, natural gas or hydrogen boiler, control system and the fitting cost. |
| C: DR | C: Demand response | Capital cost of demand response technologies |
| R: Electricity Export | R: Electricity Export | Estimated revenue from electricity export (calculated based on the average electricity cost) |

1. All costs are presented as real value in 2020. [↑](#footnote-ref-2)
2. It is assumed that all electrolysers are large-scale and transmission grid connected. [↑](#footnote-ref-3)
3. UK Gov, https://www.gov.uk/government/news/uk-signs-agreement-on-offshore-renewable-energy-cooperation [↑](#footnote-ref-4)
4. National Grid ESO, Future Energy Scenarios 2022, 2022, Available at https://www.nationalgrideso.com/document/263951/download [↑](#footnote-ref-5)
5. Derived from Leading the Way 2050 in FES 2022 by National Grid ESO [↑](#footnote-ref-6)
6. Carbon Trust, G.Strbac, D.Pudjianto,”Flexibility in Great Britain,” May 2021 – Available at: <https://publications.carbontrust.com/flex-gb/analysis/> [↑](#footnote-ref-7)
7. G.Strbac, D. Pudjianto, et al,”Analysis of Alternative UK Heat Decarbonisation Pathways”, a report to the Committee on Climate Change, June 2018. Available at: <https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf> [↑](#footnote-ref-8)
8. G. Strbac, M. Aunedi, D. Pudjianto, F. Teng, P. Djapic, R. Druce, A. Carmel, and K. Borkowski, “Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies,” Imp. Coll. London, NERA Econ. Consult., 2015. [↑](#footnote-ref-9)
9. D.Pudjianto, Luis Badesa, G.Strbac,” Whole-system value of long-duration energy storage in a net-zero emission energy system for Great Britain,” a report for SSE Renewables, Feb 2021. [↑](#footnote-ref-10)
10. The annuitisation of capital cost considers hurdle rates and payment periods. [↑](#footnote-ref-11)
11. Because of this, the Opex for electricity in IWES can produce lower estimates than other models, notably BEIS’s Dynamic Dispatch Model [↑](#footnote-ref-12)
12. The cost information on DAC is based on the 2018 report by the US National Academies titled "Negative Emissions Technologies and Reliable Sequestration: a research agenda." [↑](#footnote-ref-13)
13. Operating cost of electrolysers is part of the power sector costs. [↑](#footnote-ref-14)