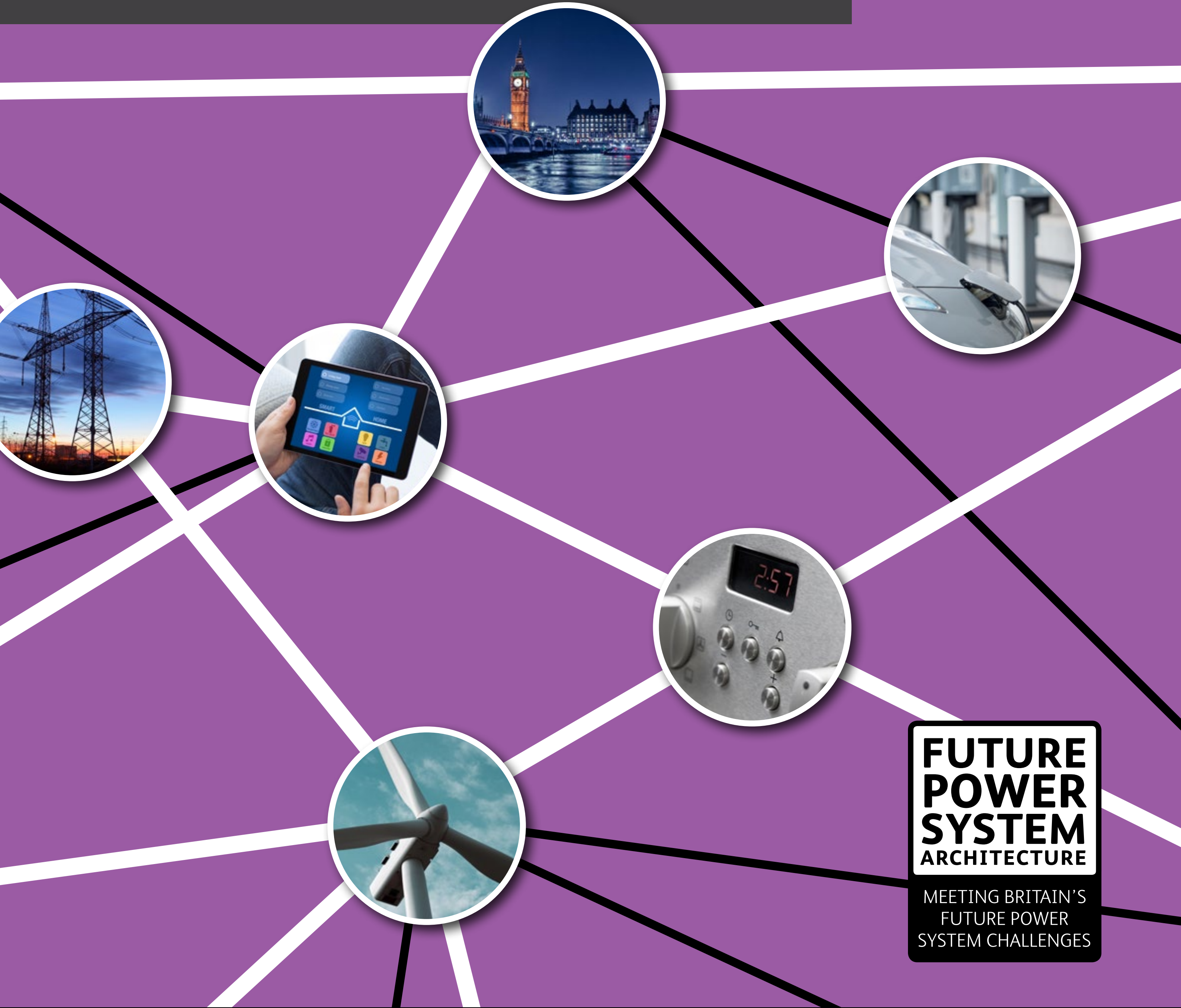
The Institution of Engineering and Technology

CATAPULT Energy Systems

Future Power System Architecture Project 2

Work Package 3 Final Report - Impact Analysis

A report commissioned by Innovate UK and delivered through a collaboration between the Institution of Engineering and Technology and the Energy Systems Catapult.



Future Power System Architecture Project 2

Final Report

Work Package 3: Impact Analysis

Future Power System Architecture – A report commissioned by Innovate UK

The Future Power System Architecture (FPSA) project 2 was commissioned by Innovate UK and delivered through a collaboration between the Institution of Engineering and Technology (IET) and the Energy Systems Catapult.

The collaboration built upon the shared commitment to respond effectively to the challenges presented by the energy trilemma: decarbonisation, security of supply and affordability. The Energy Systems Catapult and the IET drew upon their respective strengths and engaged with a broad community of stakeholders and other experts to deliver the project.

The collaboration brought extensive expertise and experience to the project, combining technical, commercial and customer perspectives, and included the significant contribution of senior thought leaders from the IET membership. The unique combination of complementary skills enabled innovation in approach, deep analysis and strong evidence building. The collaboration worked closely on project governance, delivery and commercial management and applied best practice in all aspects of its work. The position of the IET and the Energy Systems Catapult in the energy sector assured independence of the outcomes.

About the Institution of Engineering and Technology

The Institution of Engineering and Technology is one of the world's largest engineering institutions with over 167,000 members in 127 countries. It is also the most multidisciplinary – to reflect the increasingly diverse nature of engineering in the 21st century.

The IET is working to engineer a better world by inspiring, informing and influencing its members, engineers and technicians, and all those who are touched by, or touch, the work of engineers. The Institution of Engineering and Technology is registered as a Charity in England and Wales (No. 211014) and Scotland (No. SCO38698).

About the Energy Systems Catapult

The Energy Systems Catapult is the UK's technology and innovation centre set up to support companies and Government for the development of new products and services to address the new commercial opportunities created by the transformation of UK and global energy systems (covering electricity, heat and combustible gases).

The Catapult's mission is to bring the worlds of industry, academia and Government together to encourage and support the development of new technology-based products and services in the energy sector. It is a non-profit, non-partisan company limited by guarantee.

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1. Executive Summary

WP3 has identified the barriers to developing and implementing the FPSA1 *thirty-five* functions in the context of current sector arrangements, and has assessed the consequences of late or non-delivery of the functions. This is a crucial first step towards developing a strategy to overcome obstacles that arise typically where current sector mechanisms or processes are no longer fit for purpose in a world where change is becoming more rapid and there are many new stakeholders, many of whom operate 'beyond the meter'.

A fundamental learning point from the FPSA programme is that an architectural approach will be key to developing Great Britain's power system if it is to meet future needs. This requires a truly whole-system approach such that the changes to the physical network, market structures, regulatory and commercial codes, and customer behaviours can be addressed in an agile and integrated manner to meet the requirements of all stakeholders.

An impact analysis has been applied to identify and assess those barriers, broadly consistent with the methodology of a classic risk assessment. The main aim of our approach is to highlight and evidence key industry barriers and specific barriers for each function and across all functions. This supports development of Research, Design, Development (RD&D) and Innovation initiatives (see WP2) and pre-structuring of *Enabling Frameworks* (see WP4).

The highest priority barriers are those associated with existing industry governance processes, the regulatory framework, the commercial framework and the extent of technical change required. These barriers are found to be significant challenges, as demonstrated by robust evidence and analysis. It should be noted that encouragingly there are a number of ongoing innovation projects being delivered that aim to address some of these challenges.

Industry code governance
Whilst acknowledging Ofgem's review of code governance following the CMA's recommendations, the existing process of industry code governance is not sufficiently agile or flexible to respond to the degree and pace of future change envisaged. Implementation of functions will require significant interaction with technical and market codes and potentially complex and rapid changes in a system wide context.

Whilst fundamental code reviews must be given sufficient time for due consideration and consultation, a significantly more agile approach will be needed to support rapid and efficient sector response, engaging a larger group of stakeholders that includes those that operate 'beyond the meter'.

Technical challenges to implementation
Future networks will be associated with increasing complexity, stakeholders and interaction with other vectors. However, there is currently a lack of a 'whole-systems' modelling and forecasting approach in sufficient granularity to support cost effective co-ordination of planning and operation. There are also significant new data processing and interfacing implications to enable forecasting for an increased volume of Distributed Energy Resource (DER) across the system both for centralised and decentralised systems.

Enhanced modelling should incorporate greater integration of power system and market models, a more probabilistic approach and consideration of multi-vector interactions to fully capture the full value of DER and future flexibility services.

Existing monitoring, control and communications systems are not at the level of sophistication and resilience required for a number of functions. There is limited monitoring and control specifically at lower voltage levels of the distribution network. Existing control strategies particularly at distribution network level (or smart city) are also not sufficiently robust for future complex power flows and flexibility/balancing actions, and there is limited integration of controllable DER with network management software.

There is likely to be a significant increase in communication links and data sharing between the GB system operator, network operators, third parties and customers in future leading to concerns regarding cyber security. Existing industry standards do not fully address the challenges and risks associated with the significant increase in communications links between a wide range of parties on critical power infrastructure. There are also significant implications for consumer data protection.

Regulatory framework
Existing licensing arrangements do not account for new parties and new business models. For example, the transition from DNO to DSO may require new roles and responsibilities to be defined within the distribution licence. Existing regulatory arrangements are not well suited to the business models of local energy service providers (such as community energy schemes or smart cities). There are also potential risks around commercial sensitivity, data security and anonymity, particularly if sharing of data between multiple parties is required.

The whole-system is not currently considered holistically, though it is acknowledged that the ENA TSO-DSO project is actively exploring mechanisms for co-ordinated transmission and distribution planning. And whilst misaligned transmission and distribution price control periods do not in themselves prevent investments delivering cross-boundary or whole-system benefits, new mechanisms and/or incentives are required to encourage such investments. There is currently no regulatory mechanism for incentivising interventions which deliver benefits across vectors – i.e. electricity and gas networks.

Current network charging arrangements act as a potential barrier to maximising benefits of local community energy schemes and peer-to-peer trading. The ENA TSO-DSO project has a workstream dedicated to network charging and Ofgem is aware of the need to ensure that wider network costs are appropriately and equitably shared across customers, including where communities become more self-sufficient in electricity production. A wider range of stakeholders including smart cities and communities also need to be engaged more fully in the regulation of markets. A more holistic approach to regulation and markets across the energy sector might encourage and exploit synergies and reduce the risk of unintended consequences arising from changes to codes, legislation, policy and regulation.

Balancing the potentially competing requirements for investor certainty and sector agility will be a key challenge for power system regulation in the implementation of new functions.

Commercial framework
Existing commercial arrangements can sometimes act counter to core policy objectives. For example, the current structure of network and system balancing charges, coupled with double charging of renewable energy levies, can have an adverse impact on the business case for energy storage. Moreover, current licence limitations on network operators regarding the ownership and commercial operation of energy storage might act as a barrier to its use as an effective means of network constraint management.

Existing services may not be sufficient to support the system, for example in the event of a Black Start new commercial models might be needed to meet these requirements. For example, there will be commercial challenges around securing new Black Start services, recognising the increasing need to recruit local generation and demand response given a significantly different generation and demand portfolio in 2030 than exists today. An Energy Emergencies Executive Committee (E3C) task force has been set up to consider the changing needs for Black Start.

There is uncertainty around the required level of customer engagement with the electricity system to deliver effective flexibility and ancillary services – and hence the construct of commercial frameworks that will provide the necessary incentives.

Finally, new commercial arrangements may be complex to design and implement, and this complexity could itself be a barrier. Functions that require co-ordination between different parties could lead to concerns over how commercially sensitive data is treated, or over how conflicts of interest are tackled.

Overall implications
Overall the analysis has demonstrated that the current power industry arrangements are not conducive to the timely delivery of the new or extended functionality identified by the first phase of the Future Power System Architecture Project FPSA1. This has potential implications for achieving the goals of the Government's energy policy – i.e. a secure, affordable and low carbon energy future.

2. Introduction

2.1 Background

The Future Power System Architecture (FPSA) programme seeks to create a dynamic environment in which to develop the GB power system architecture, taking a holistic and whole-system perspective. Working across the electricity industry, involving the full range of stakeholders, is key to this approach, creating a shared view of a future in which electricity customers are at the heart of the overall system.

The first stage of the project, FPSA1, which reported in July 2016, called on the power industry and Government to focus urgently on delivering new capabilities to transform Great Britain's power system architecture by 2030, making it fit to respond to the challenges presented by the energy trilemma.

The purpose of the next stage, FPSA2, was to understand current barriers to implementing the required new functionality in the power system to support changing customer and societal needs, and to address the trilemma of decarbonisation, security and affordability. FPSA2 proposes an alternative more agile approach enabling inclusive stakeholder collaboration and a framework for ensuring timely delivery of functionality at a whole-system level.

The delivery objectives for FPSA2 are:

- A comprehensive exploration of the current and future requirements of both existing and emerging stakeholders.
- A review of the *thirty-five* FPSA1 functions to identify possible gaps or new insights into required functionality.
- An assessment of the feasibility of delivering the functions under the current power sector structure.
- Identification of possible early RD&D and Innovation (Research, Development & Demonstration and Innovation) actions to support the ambitions of future FPSA work streams.
- A methodology for assessing the probability and consequence of late or non-delivery of the functions.

- A methodology for determining the relative impact of the identified barriers to functions under the current structure, and hence the priorities for establishing *Enabling Frameworks* to address those barriers.
- The identification of a number of *Enabling Frameworks* for development under FPSA3 to deliver the functions.
- An overall systematic approach to FPSA2 that would ensure development of practical methods for dealing with the complexity and uncertainty of innovative transformation in the electricity sector.
- Full documentation of both the methodology and outputs to provide the necessary audit trial and overall process assurance.
- A clear explanation of the complex messages delivered to relevant audiences throughout FPSA2.

The tasks for FPSA2 are split into a number of Work Packages to enable project activity to be co-ordinated and managed effectively. A Work Package champion lead each Work Package, supported by external suppliers and contractors to deliver the work. The main tasks associated with each Work Package are summarised in the table opposite.

2.2 WP3 context within FPSA2

Understanding and clearly articulating the existing implementation barriers to future required power sector functionality as defined and detailed in WP2 is a crucial first step towards developing a strategy to overcome those barriers. Providing some quantification of the consequences of not overcoming those barriers is also helpful to understanding the significance of each barrier and directing efforts accordingly. This is the role of WP3 within the FPSA2 project.

More specifically, WP3 provides an important output to WP4 by identifying key barriers to function implementation under the current structure that need to be addressed as a priority. Function delivery options and RD&D and Innovation opportunities explored in WP2 are also informed by the barriers that are identified in WP3.

Stakeholder views on market and implementation barriers captured in WP1A help to inform the analysis of WP3 and contribute to evidencing of difficulty and consequence.

Figure 2-1: Tasks within each FPSA2 Work Package

WP1A: Engage with Stakeholders
Establish a survey technique to identify the barriers being encountered, especially for communities and grid-edge technologies.
WP1B: Future Stakeholder Needs
Research future socio-political drivers on customer and stakeholder behaviour.
WP2: Review the Functional Analysis, Identify no-regrets actions, assess RD&D required to accelerate deployment
Check validity and completeness of functions and options for delivery. Progress no-regrets actions where feasible through today's sector processes, including touch points with other vectors. Identify RD&D and Innovation opportunities to accelerate delivery.
WP3: Impact Analysis
Identify the barriers to developing and implementing the functions within current sector processes and assess the impact of late or non-delivery.
WP4: *Enabling Framework* Identification
Assess architectural options to remove institutional (regulatory, market, technical, cultural, etc.) barriers to delivering functions. Identify *Enabling Frameworks* and potential trials for development under FPSA3.
WP5: Synthesis Integration and Reporting
Ensure key findings are integrated between Work Packages and deliver final reports.
WP6: Dissemination
Ensure complexities of FPSA are appropriately shared to audiences. Explore improved communication techniques.

2.3 Objectives

The objective of this Work Package is to assess the implementation barriers to the introduction of new functionality under the existing sector technical, commercial, regulatory and institutional landscape. This was achieved by:

- Determining the **impact of current implementation barriers** on delivery of functions.
- Identifying the **risk to energy policy** of late or non-delivery of functions.
- Enabling **priorities to be assigned** to resolution of barriers and enabling of functions.

2.4 WP3 interactions with other Work Packages

A vital aspect of the WP3 methodology has been the interaction with other Work Packages in the wider FPSA2 team, to support and validate the work being done in WP3 and also to shape the analysis and enablement activity being undertaken in the different Work Packages. The following table describes the various interactions with the other Work Packages and highlights the bilateral contributions throughout the project.

2.5 Report structure

The work undertaken by WP3 comprises three distinct parts:

1. Impact analysis methodology.
2. Assessment of function barriers and consequences.
3. Identification of most significant barriers.

The report is therefore structured in the following way:

- Section 3 outlines the methodology used to carry out the impact analysis including definitions.
- Section 4 provides details of function barriers and consequences with relative scores, descriptions and evidencing.
- Section 5 provides detailed analysis of the three test case functions which are also explored to a similar level of detail in WP2 and WP4.
- Section 6 describes the most significant implementation barriers across all functions, based on the impact analysis.

WP	Description of Interaction Requirement	Contribution from WP	Contribution to WP
1A	To support identification of existing barriers to function implementation.	Validation of function implementation barriers, including for the three test cases.	Questions for stakeholders and participation in specific focused interviews to support validation.
2	To correlate the function needs with their barriers and challenges.	Function needs to better understand the various barriers to implementation.	Barriers and urgency of functions to identify RD&D and Innovation options.
4	To describe function barriers to facilitate the development of suitable *Enabling Frameworks*.	Guidance on the required outputs from WP3 regarding the function barriers.	Provision of detailed function barriers for the three test cases.
5	To facilitate synthesis of the work in WP3 with the overall FPSA2 project.	Direction and steer on WP3 outputs and narrative.	WP3 outputs and narrative.
6	To provide outputs from WP3 suitable for widespread dissemination.		Function groupings for dissemination.

3. Approach

3.1 Impact analysis methodology

WP3 identified barriers to developing and implementing the functions in the context of current sector arrangements, and assessed the consequences of late or non-delivery of the functions.

The WP3 methodology was designed to define a measure of the risk to the delivery of energy policy with respect to each of the functions. The methodology is broadly consistent with that of a risk assessment. The number and materiality of the barriers for each function is assumed to correlate with the probability of the function not being delivered (due to inability of the sector to overcome these barriers). Together with the consequences of delivering the function late or non-delivery (the impact of not delivering the function), the risk to delivery of energy policy can be quantified. This quantitative approach allows for identification of functions with relatively higher difficulty and consequences and the prevalence of different types of barriers. The methodology therefore quantifies risk in relative rather than absolute terms.

The methodology was refined in the early stages of the project, building from an original outline approach developed in advance by the Steering Group. The relative risk to delivery of energy policy combined assessments of difficulty, consequence and immediacy, where the assessment of:

- Difficulty - identified the barriers to implementation of each function, and related to the probability of the function not being delivered due to the inability of sector to overcome these barriers with current sector arrangements.
- Consequence - considered the extent to which the decarbonisation, security and affordability objectives of energy policy would be impacted by late or non-delivery of the function.
- Immediacy - provided a way of indicating the order in which functions need to be delivered, considering interdependencies and the FPSA1 Evolutionary Pathways. The inclusion of the immediacy parameter enabled consideration of function sequencing in prioritising the removal of function barriers.

Barriers and consequences that apply to the functions were reviewed and categorised. Barrier categories were defined as Technical, Commercial, Governance and Societal. Consequence categories were defined, according to the trilemma, as Decarbonisation, Security and Affordability. Detailed descriptions of barrier and consequence categorisation are provided in Annex A.

Difficulty (based on the barriers), Consequence and Immediacy were then assessed for each function. The three test case functions selected to validate the *Enabling Frameworks* in WP4 were subject to more detailed barrier analysis.

Analysis and interpretation included results of visualisation, function prioritisation and barrier prioritisation. Visualisation of results includes a range of different graphical techniques including radar plots where the degree of Difficulty and Consequence is indicated between 'low' close to the centre of the of the plot, to 'high' at the edge of the plot - see examples opposite.

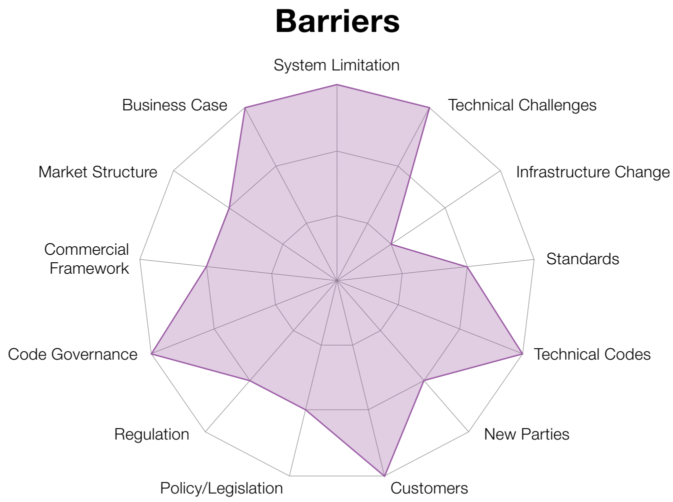
Function prioritisation helped to inform work by WP2 on identifying potential RD&D and Innovation activities, by focusing on functions with high consequence and high immediacy. Barrier prioritisation identified barriers that are most prevalent across all functions, analysis which can be used going forwards to inform the development and focus of *Enabling Frameworks*.

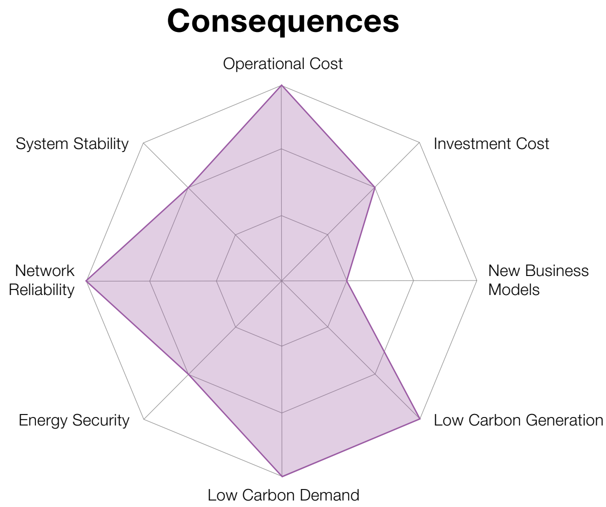
A review and verification process was developed to ensure that the final results are robust, defensible and not significantly influenced by individual or group biases. This included a peer review within the WP3 team and with the WP3 champion, and a peer review with the wider FPSA2 team including a detailed review of the three test case functions.

Further details of the methodology are provided in Annex A and the impact analysis model is provided in Annex B.

3.2 WP3 definitions

Definitions of key terms relevant to this Work Package are provided opposite for ease of interpretation.





(Implementation) Barrier: A technical, commercial, industry governance or societal obstacle that prevents or delays a function being implemented. Overlaps with market barriers to entry for new parties.

Consequence: The result or effect of not implementing the function on security of energy supply, decarbonisation targets and affordability of the power system.

Accommodation: Adaption or adjustment of the power sector to the needs, wants and expectations of both customers and stakeholders, and new sector parties.

4. Function Barriers and Consequences

4.1 Function groups

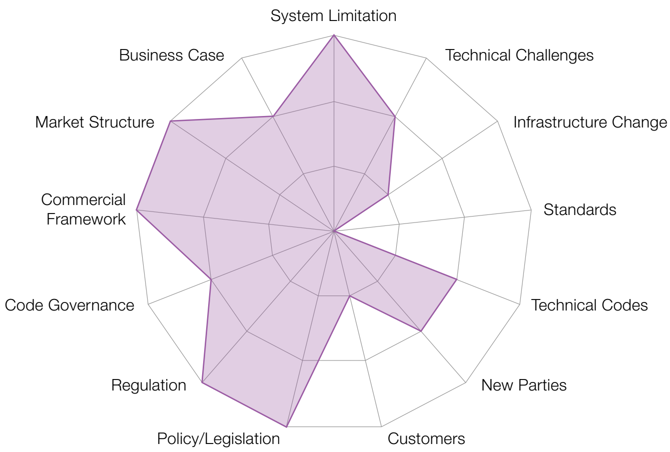
WP2 has categorised the *thirty-five* functions into eight groups based on the role they will perform in the power system. These roles are described in Table 4-1 below with further details contained in the WP2 report. The functions were given a unique number identifier in FPSA1; however a new numbering scheme has been employed in FPSA2 to correspond to this new grouping approach.

Table 4-1: Function Grouping

Function Grouping	
A	Design a competitive framework to deliver the energy trilemma.
B	Manage the interface with connected energy systems.
C	Form and share best view of state of system in each time scale.
D	Use smart grid and other technologies to accommodate new demand, generation and energy resources.
E	Enable and execute necessary operator interventions.
F	Monitor trends and scan for the emerging risks/opportunities on the power system and implement appropriate responses.
G	Provide capabilities for use in emergencies.
H	Develop markets to support customer aspirations and new functionality.

4.2 Design a competitive framework

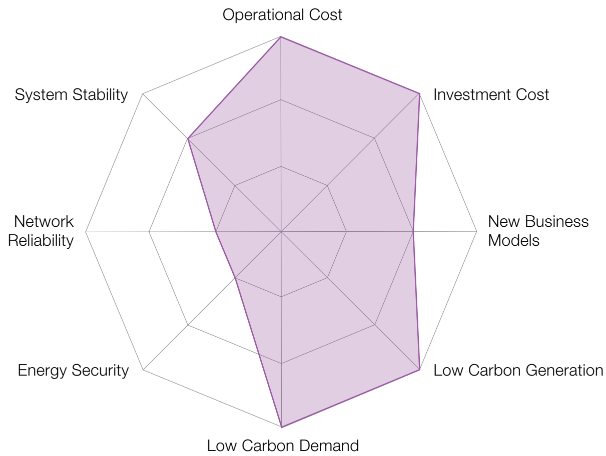
A1 Provide mechanisms to model portfolios of generation, other energy resources, EU interconnection and ancillary services to measure these against the GB carbon reduction, security of supply and energy affordability policy objectives and plan for the delivery of those portfolios that best meet these objectives.



Implementation barriers

Planning for delivery of a portfolio which fulfils policy objectives may be constrained by the ability of the system to accommodate that portfolio. For example, meeting decarbonisation targets is likely to require a high level of intermittent and asynchronous renewable generation, which has implications for system strength and stability, power quality and transmission system protection co-ordination [1]. Modelling capability needs to be enhanced in order to provide a whole-system view of portfolio performance, and this would have to be capable of capturing interactions across the whole-system (including autonomous parties such as smart cities and multi-vector interactions) [2].

Implementation of this function will require clear, measurable policy objectives to be set by the Government, and uncertainty as to policy could therefore be a barrier to planning. Significant legislative and regulatory change and new requirements on licensed parties [3] might be required to implement new policy mechanisms e.g. implementation of the Capacity Market and Contract for Difference commenced with a consultation on Electricity Market Reform in 2010 and was achieved through the passage of the Energy Act 2013 and supporting secondary legislation. Portfolios and the mechanisms to model them would have to be accommodated within codes, with changes made through the existing framework which may not be sufficiently agile [4]. Policy mechanisms will need to fit within the overall market structure and this may not be appropriate for a future portfolio – e.g. an energy market may not appropriately value capacity and flexibility, and widespread adoption of subsidised renewables (which have very low short run marginal cost) will probably lead to many periods of low or even negative prices [5]. New mechanisms will also need to work within the existing commercial framework, where existing mechanisms (like the Capacity Mechanism and Contracts for Difference) have awarded long-term contracts to many new power stations.

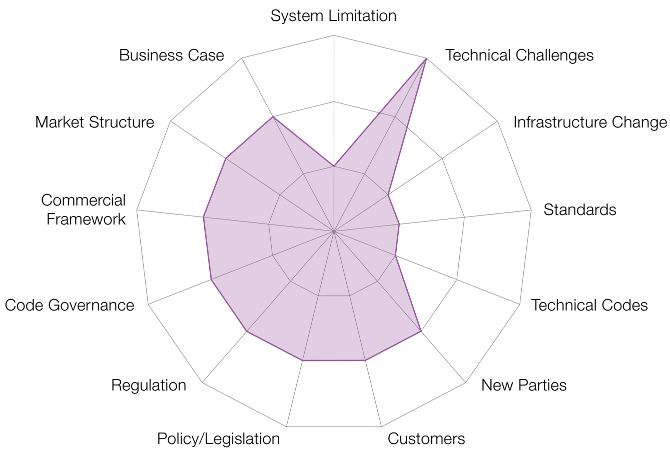


Consequences

Without implementation of this function, it is likely that energy security and network reliability would continue to be provided (e.g. through existing measures like the Capacity Market, or through reintroduction of energy measures such as Supplemental Balancing Reserve and Demand Side Balancing Reserve), but there could be risks to system integrity and stability e.g. if impacts of renewable deployment are not well understood. However, it is likely that this would increase the overall cost of the system, with inefficient investment in new assets and expenditure on operational actions (such as expensive reserves or capacity) required in order to deliver this security, that did not fully capture the capabilities of the generation mix and DER. Decarbonisation efforts would likely fail to meet policy objectives without mechanisms to support this.

4.3 Manage interfaces

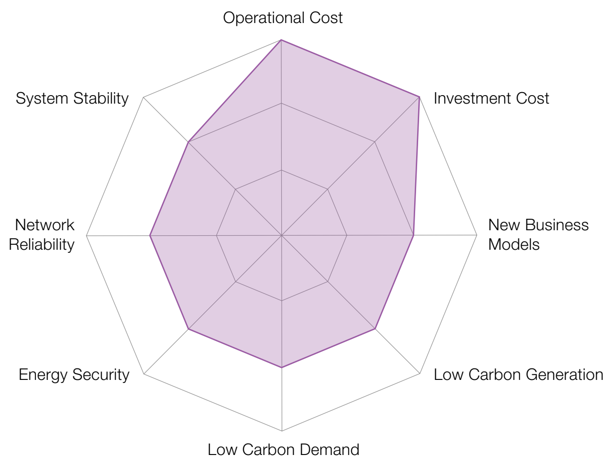
B1 Account for the impact of operational interactions (potentially including cross-vector, cross-border and intra-power system) in system planning and forecasting of demand, generation, energy resources and ancillary services on the power system.



Implementation barriers

Lack of policy certainty around key issues, particularly the pathway to decarbonisation of heat, makes it very difficult to assess the interaction of the power system with other energy vectors, particularly the gas network, but also district heating and hydrogen. There are clearly interdependencies between the levels of future demand on the electricity network and the demands on the gas network. However, the current regulatory framework does not explicitly ensure that trade-offs between electricity and gas demand are captured within the investment planning of the two sectors. There are also barriers associated with variation of codes among energy vectors, and different interpretations of implementation [6].

Multi-vector interaction will require a new and complex market structure. Exactly what such a market structure will look like and what new types of parties may be involved is uncertain and this will affect the ability to forecast interaction. The business case might be quite difficult to justify due to the significant complexity of an interconnected system and uncertainty of benefits. The technical difficulty associated with assessing the impact of multiple energy vectors and sectors could prevent many organisations from being able to account for this within their forecasting. Existing modelling capability is not sophisticated enough to consider this at the temporal and spatial resolution required [2]. Many of these barriers also apply to the assessment of interactions that occur within the power system, e.g. between TSOs and DSOs or between the SOs of interconnected countries.



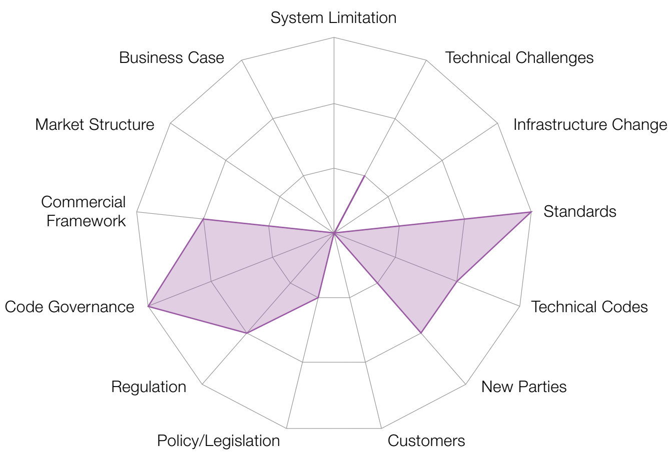
Consequences

The most significant consequences for delayed implementation of this function are related to costs. Inefficient operational costs may occur due to lack of consideration of cross-vector, cross-border and intra-system interactions resulting in balancing conflicts and lost synergies. Cost may also be higher due to smaller market size for balancing services and innovative business models discouraged.

Investment costs providing network capacity are likely to increase where opportunities for optimisation with the gas network for example are not fully considered. Low carbon generation and demand will require significant additional capacity and any capacity release through cross-vector interactions for example, should help manage cost.

Lack of consideration of operational interactions also puts the system at risk in terms of supply reliability and stability.

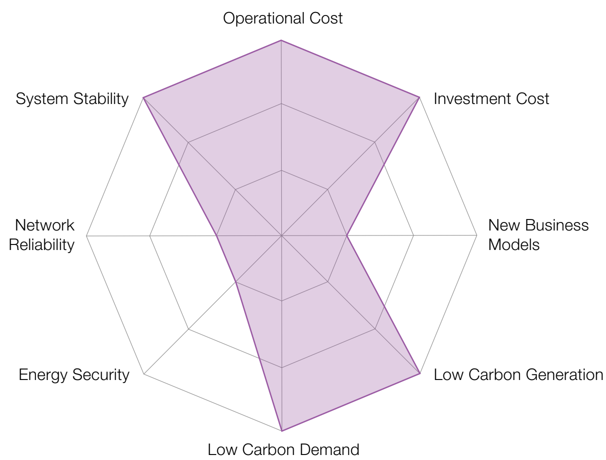
B2 Provide mechanisms by which planning can be co-ordinated between all appropriate parties (potentially including cross-border, cross-vector, and intra-power system operational interactions) to drive optimisation, with assigned responsibility for security of supply.



Implementation barriers

Greater co-ordination of planning activities may require regulatory changes to support the definition of roles and responsibilities. For example, increasing the co-ordination of transmission planning has changed the role of the SO and given it new responsibilities such as the Network Options Appraisal process [7]. Industry codes and standards such as SQSS and P2/6 do not currently account for complex interactions between connected systems and do not fully consider the contribution of future flexibility services to network capacity [6]. Future planning approaches will need to consider the conflicts and synergies that might arise when different parties attempt to access the same flexibility resources and use them in different ways. The use of probabilistic methods which recognise the security contributions from distributed generation and demand would support this. The current P2/6 review is considering these issues.

New code requirements for sharing of data may need to be introduced e.g. to promote more co-ordinated sharing of network data between system operators (including other energy sectors), local and regional authorities, smart cities etc. and more accurate provision of dynamic models from generators. Fundamental review and modification of industry codes is likely to be a very lengthy process, involving a large number of (new) stakeholders and existing change processes may not be sufficiently agile to support this [4]. The lack of transparency and accessibility of network data for planning is a potential barrier for the accommodation of new parties. Only limited annual peak loading data is generally available in Long Term Development Statements down to 33kV or 11kV and there is limited visibility of other (competing/conflicting) planning applications in the same network area for generation or storage for example. Developers of smart cities and community energy schemes may require access to historical loading data in order to optimise planning and security of supply of independent distribution networks. Identifying these ‘autonomous’ parties in order to engage them in planning activities may be challenging.

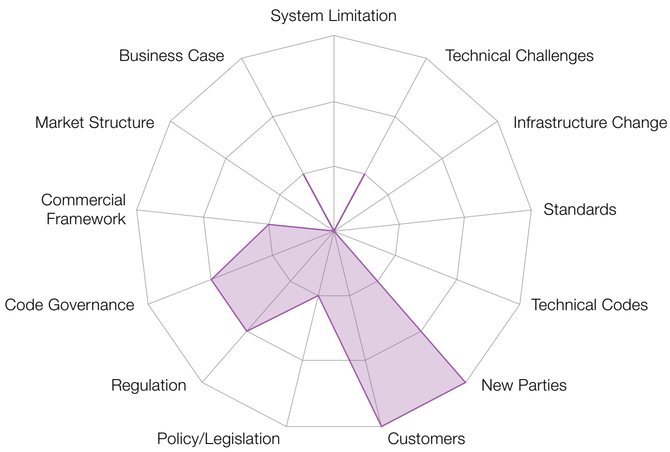


Consequences

Without effective co-ordination between various parties such as the Regulator, network operators, generators, demand aggregators, smart cities etc., there may be sub-optimal utilisation of existing network and generation/storage capacity. Further investment in network assets would then be required to reinforce growth in low carbon generation and demand. Inability to capture the full value of flexibility services to network capacity may result in lack of feasibility of new business models including aggregated demand side response and energy storage. This could have a knock-on impact on low carbon generation and demand where connection costs and wider reinforcement costs increase. Also, lack of co-ordination may not provide appropriate locational signals for new generation.

Without co-ordination of network planning, there may be a higher number of conflicts between different system operators and energy sectors, leading to inefficient operational costs due to the need to procure more system services.

B3 Provide operational planning processes that facilitate engagement with all affected stakeholders (potentially including cross-border, cross-vector, and intra-power system operational interactions), taking account of the appropriate level of engagement for different stakeholders.



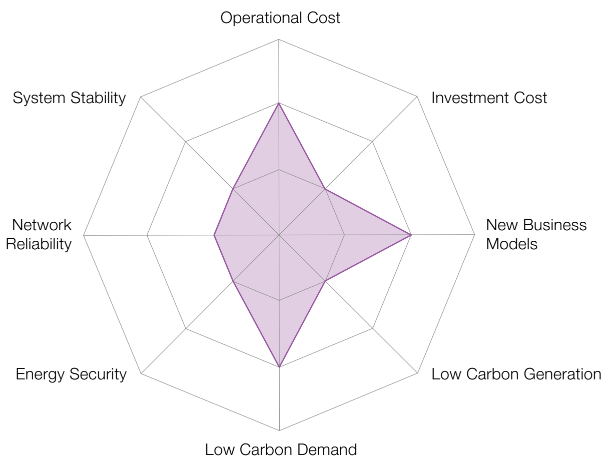
Implementation barriers

The most significant barriers to this function relate to accommodation of new parties and customers. The existing operational planning process involves a fairly limited number of parties. It is envisaged that in future, with more complex power flows and operating points, there will need to be greater engagement with a range of stakeholders including new flexibility and balancing action service providers such as aggregated DSR. There may be a lack of technical capability and capacity [8] to engage with system operators, co-ordinate data provision [9] and consider the potential impact of operational plans on business models. Lack of historic data may also be a barrier for new service providers.

Currently, there is also little engagement with customers on operational planning; however customers may be involved in providing aggregated services in future. Where aggregated services are providing constraint management or balancing actions, this will have a direct impact on customers and the business models of the services that they are providing. There is a need for engagement and education of customers to ensure that value of flexibility services is fully captured.

The existing regulatory framework is not appropriate for roles and responsibilities of stakeholders that might be involved in future operational planning e.g. it does not define the roles and responsibilities of a DSO (or smart city, private wire) and co-ordination with TSO and other DSOs [10], [11]. Also, electricity and gas is regulated separately and there is no regulatory incentive to sharing of network operational data (which may be sensitive).

Existing industry code does not reflect levels of stakeholder engagement that may be required for future operational planning. A whole-system perspective may be more appropriate that includes balancing actions at distribution level [10] and multi-vector and greater intra-system interaction.

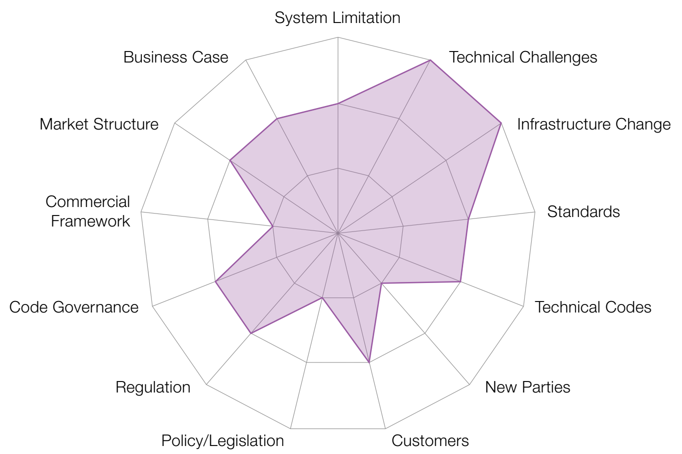


Consequences

An operational planning process that does not engage all stakeholders may result in impediments to new business models such as aggregated demand side response for example or smart cities. Uncertainty regarding the operational planning process due to lack of engagement may flow on to business models and customer appetite. This could have an impact on accommodation of low carbon generation and demand, where the full value of intermittent renewable generation and low carbon demand to the system is not captured.

Inefficient operational costs may be incurred from reduced availability of flexibility and multi-vector/intra-system services and inefficient operational planning.

B4 Enable the delivery of demand control, generation constraint, co-ordination with other system operators (potentially including cross-border, cross-vector, and intra-power system operational interactions) and other actions in response to all system incidents.

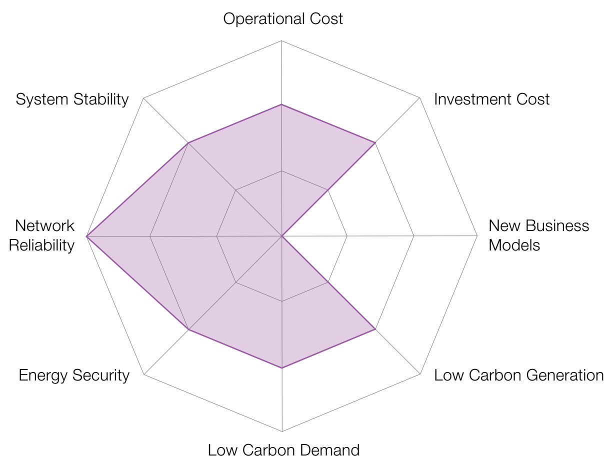


Implementation barriers

There are predominantly technical barriers for this function such as lack of co-ordination of suitable control and protection infrastructure e.g. ramped control of demand in response to cold-start re-energisation [4], lack of demand control for frequency response, lack of communications infrastructure [12] and integration with network control systems. For example, when an area of network is re-energised in future after a period of shutdown (particularly in cold weather), the simultaneous demand from large heat pump and EV charging loads could greatly exceed network capacity and result in an immediate re-tripping of supplies or threaten the national energy balance [4].

Also, active network management capability is still limited across the system with insufficient regional and national co-ordination to fully respond to extreme events with moderation or disconnection of DER.

Existing grid codes (e.g. Electricity Supply Emergency Code) do not reflect emergency actions which could be taken using a full range of distributed flexibility services [3]. There is also a lack of visibility and co-ordination between different/new parties that might contribute to various actions under extreme events and licensing requirements may not fully reflect roles of flexibility services [3], [13].



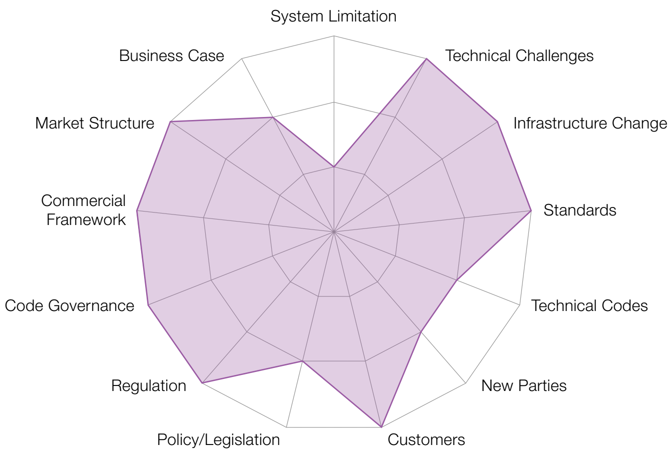
Consequences

The most significant consequence for non-delivery of this function is impact on reliability and security of supply of networks. Failure of the system to respond with appropriate demand control and generation constraint to extreme events could lead to load-shedding, brown-outs or even black-outs.

In a future network with increased intermittent generation and low carbon load, the inability to control system load in extreme events may also result in higher investment in fossil fuel generation to provide increased flexibility. The less flexibility there is in the system to address extreme events, the less competition there is to provide associated services and the more expensive they will be.

This may also reduce ability to accommodate low carbon generation if mitigating actions under extreme events are limited. Heat ramps (large pick-up of heat pump load) during cold snaps could become an extreme event, reducing the ability to accommodate low carbon demand.

B5 Collaborate with other energy sectors (potentially including cross-border, cross-vector and intra-power system operational interactions) in order to allow the market to operate across multiple sites and vectors.



Implementation barriers

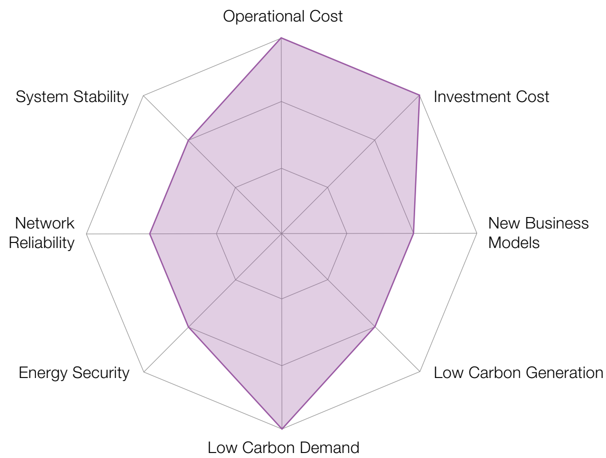
There is a lack of clear policy signals on the transition to a multi-vector energy system [14]. There is also increased uncertainty in relation to the contribution of interconnectors and market structure and commercial framework following Brexit.

Electricity and gas networks are regulated and planned independently and separately [15] so efficiencies in outputs that could be achieved through collaboration (e.g. cost recovery) are not considered in regulation. Heat networks are not subject to regulation currently. Existing licences may not be suitable for future system roles and (regional) third party service providers across energy vectors [8], [3].

A 'whole-systems' approach to network planning and operation has not yet been adopted [14] and current industry standards limit interoperability across vectors/sectors [6] e.g. gas quality regulations may block injection of hydrogen, produced by 'excess' electricity into the gas network [3]. There is uncertainty in how this would be technically implemented.

There may be significant technical difficulty in the need for implementing a more collaborative energy sector due to enhancements and greater co-ordination of modelling, forecasting, and communications and underlying uncertainty due to lack of experience. Technical codes do not yet address capacity that may be available from other vectors/sectors and how this would be managed efficiently [6]. Significant communications and IT infrastructure may also be required to foster greater collaboration.

There is a risk that there will be a lack of protection for particularly vulnerable customers due to no existing regulation of heat [3]. Lack of a regulatory framework for heat networks might also deter investment as shareholders will not have the assurance of a dependable return on investment.



Consequences

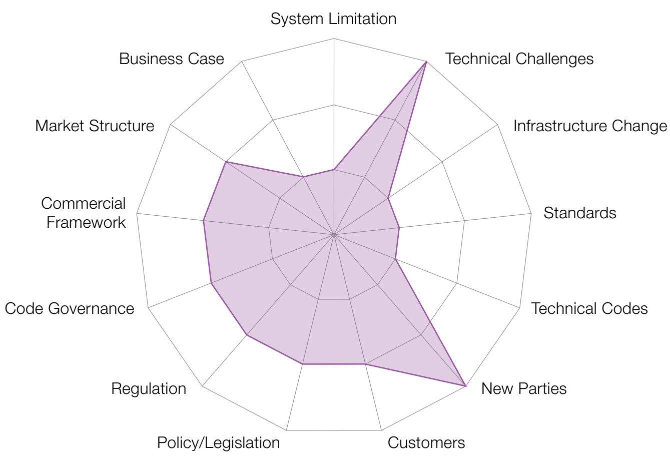
Inefficient operational costs may occur due to balancing conflicts and lost synergies in cross-vector, cross-border and intra-system interactions. Smaller market size for balancing services for example will increase costs and innovative business models that exploit multi-vector collaboration may be discouraged.

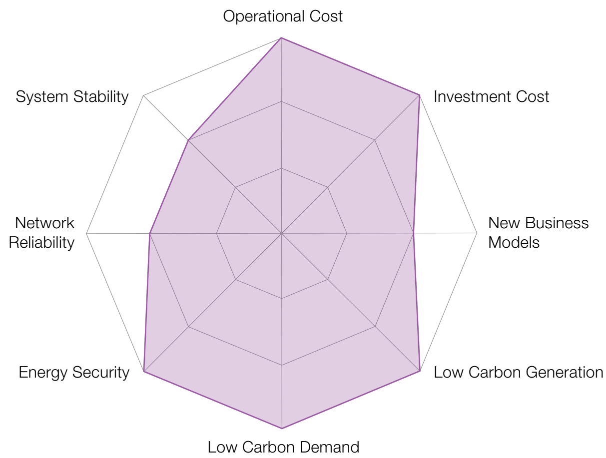
Investment costs providing network capacity are likely to increase where opportunities for optimisation with other networks are not fully considered. Low carbon generation and demand will require significant additional network capacity, even allowing for smart demand and generation export control, and any capacity release through collaboration with other energy sectors should help manage cost.

Reduced availability of system services that may occur without multi-vector/sector collaboration could put the system at increased risk in terms of supply reliability and stability.

4.4 Form and share best view of system

C1 Forecast all demand, generation, other energy resources and ancillary services across all voltage levels within the power system.





Implementation barriers
Current policy uncertainty around the future of heat and the role of other vectors such as gas and hydrogen, mean that forecasting future demand and generation on the power system is difficult. Definition of standardised scenarios for modelling is challenging in order to consider the types of generation that may connect [16]. Also, the existing regulatory framework can make it harder for new parties to participate and can distort the expected uptake of certain renewable technologies and thus make forecasting less accurate.

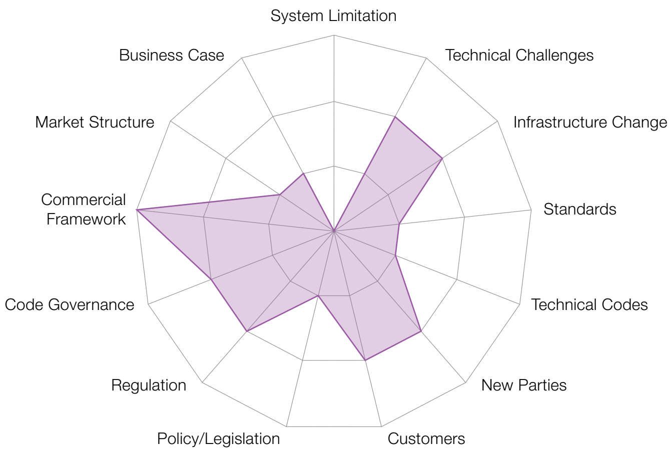
The lack of visibility of existing embedded generation and low carbon demand, and uncertainties regarding the future energy system and customer needs [17] make it challenging to forecast load hotspots. The existing Grid Code does not require mandatory forecasting for planning purposes for embedded generation <1MW and demand <5MW [18]. If changes were required to the Grid Code, this should be considered based on a whole-system and long-term approach however existing grid code governance can be piecemeal and fragmented [4].

The commercial framework and market structure currently in place does not incentivise flexibility, particularly on the demand side and there is uncertainty regarding how these will evolve. This is a barrier to forecasting when and to what extent new services and service providers will alter levels of demand, generation and ancillary service provision on the electricity system e.g. multi-vector integration.

Consequences
Inaccurate forecasting has the potential to have a significant impact on investment costs and could result in stranded assets due to loading less than forecast. This could also increase the costs of connection for low carbon generation and demand, affecting the business case and ability to meet decarbonisation targets.

Inefficient operational costs may occur due to lack of appropriate system services available to meet requirements (due to inaccurate forecasting) and so increase cost of available services. Additional, potentially high cost, constraint management services may be required where load increases more rapidly than forecast. This could also affect system security and reliability.

C2 Collate and distribute information throughout the power sector on the availability and performance of the generation, other energy resources and ancillary services, and any associated operational restrictions.

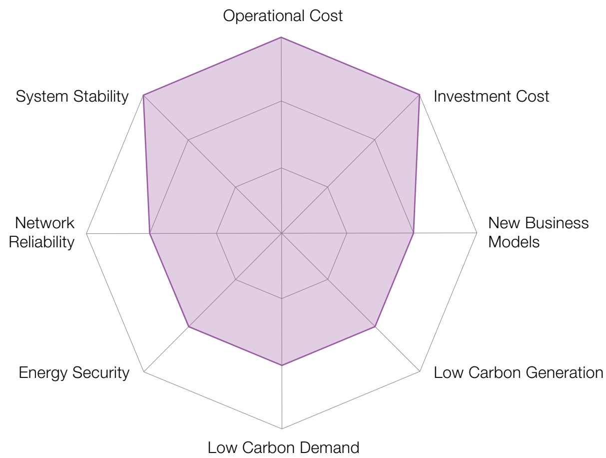


Implementation barriers

Appropriate systems and platforms for collation and distribution of information are not yet available and deployed [10]. However, this is being explored by industry, for example UK Power Networks in the innovation project KASM [19].

There is also limited infrastructure for monitoring of, and communications with, network assets and DER particularly at lower voltage levels. There is a lack of commonality and functionality for hardware and software platforms on which to collate and analyse data although industry is moving towards standards like IEC 61850 [20]. This may also require greater regional and local collation and distribution to a wider range of stakeholders than at present with increased engagement. Lack of historic data may be a barrier for new service providers; however greater transparency of data may also support these new parties to enter the market.

There may be potential new obligations on licensed parties and/or licensing of non-licensed parties for the provision of data. This has implications for commercial sensitivity for sharing availability and performance data. There will be a greater granularity of data available and more parties with access to data [8]. However, progression to a more collaborative and trust-based relationship between the Regulator and market participants may mitigate this. The co-ordination framework for this data may also influence the significance of this barrier (if market participants are submitting data to an SO, for example, compared to data being distributed to all market participants). Grid code changes may also be required to reflect new data sharing responsibilities, co-ordination and new stakeholders.

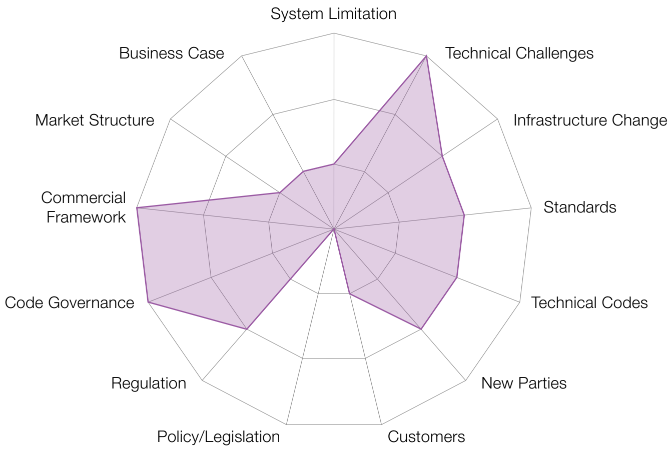


Consequences

Lack of visibility of availability and performance data for DERs for example, will prevent a wider industry understanding of how these can be contracted and deployed for maximum benefit to the system: i.e. avoidance of operational restrictions. This is likely to result in significant inefficient investment in new capacity and over-procurement of system services due to lack of certainty of performance, to ensure continued system security. System stability may be affected if information on availability and operational restrictions is not communicated with wider stakeholders, particularly with greater intra-system and multi-vector co-ordination.

Lack of visibility could also lead to more opaque business models where customers are not able to exercise an informed choice for supplier.

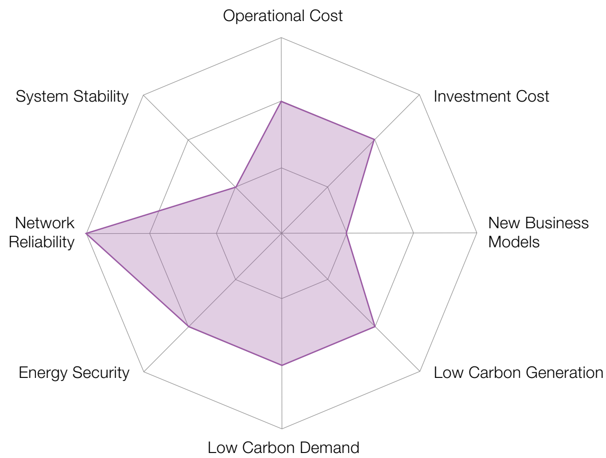
C3 Collect outage information from all parties of significance within the power sector, co-ordinate with affected parties, identify clashes and resolve, with assigned responsibility for security of supply.



Implementation barriers

There are likely to be commercial sensitivity issues for sharing (outage) data with higher granularity of data available and more parties with access to data [8] similar to C2. Greater engagement will be needed with a wide range of stakeholders including new flexibility and providers of balancing services such as aggregated DSR to collate outage data and co-ordinate operational planning to avoid conflicts. This will include co-ordination of data provision, and consideration of data sensitivity and potential impact of outage conflicts on business models. Some new parties may not be well placed to manage complex contracts and lack of historic outage data may also be a barrier for new service providers. There may be potential new obligations on licensed parties and/or licensing of non-licensed parties for provision of data and security of supply.

Technical challenges are associated with increased granularity of outage data required if there are high volumes of aggregated services and co-ordination of these services with little to no historic data. Implementation of the common information exchange standard will help to align commonality of data for analysis. Network management systems at distribution level specifically do not currently have the complex functionality to consider both technical and commercial factors for resolution and optimisation of power flows and security of supply [10], taking a whole-systems approach. Outage information in future may need to cover a range of timeframes [21], greater than considered at present. There is also limited infrastructure for monitoring, communications and health checks specifically at lower voltage levels. Appropriate systems and platforms for collation and distribution of information are not yet available and deployed [10] and there is a lack of standardisation of control and communications platforms. This is being explored by SP Energy Networks in the innovation project FITNESS [22]. KASM [19] is more broadly exploring the development of an IT architecture to improve co-ordination between SO and DNO as one of its innovative elements. Greater co-ordination between system operators and across different energy vectors may be required to avoid/resolve conflicts at different timescales however this is not currently reflected in grid codes [6], [18]. A large number of stakeholders may be involved in shaping how this develops, for example for local and regional balancing actions at distribution level [10] and multi-vector and greater intra-system interaction.

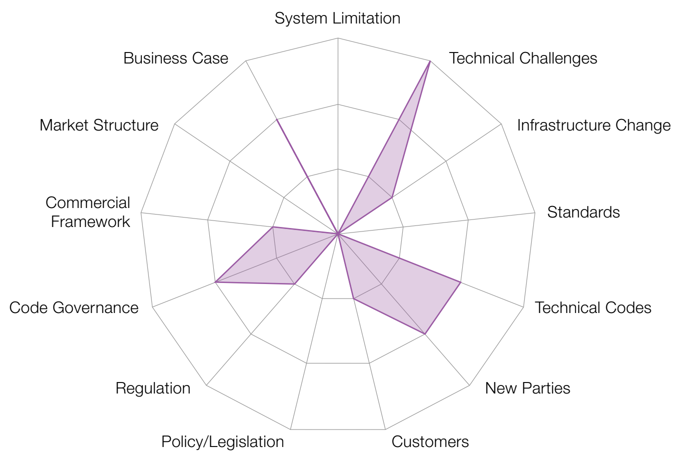


Consequences

There are consequences for network reliability where there is lack of visibility of outage information and conflicts are not efficiently identified and resolved. This could lead to exeedance of thermal or voltage constraints and tripping of circuit breakers as unco-ordinated balancing and system services actions are taken.

Lack of co-ordination of outage information is also likely to lead to inefficient operational and investment costs to mitigate uncertainty and failure to maximise the capabilities of DER.

C4 Forecast and model all generation and other energy resources and ancillary services with operational, cost, and security implications for the power sector.

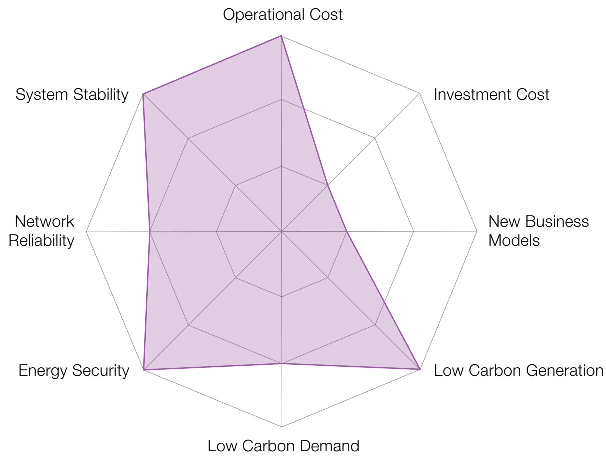


Implementation barriers

Existing modelling and forecasting capability and skills are not at the level of sophistication required to capture full value of DER and flexibility services to the network. For example, there is lack of a whole-systems approach across the systems chain or sufficient granularity to capture interactions across different locations and energy infrastructure [2]. There is limited integration between power system models and dispatch/market models.

Technical codes do not reflect the capability that might be required in future. Currently, in the Distribution Code, the DNO collates demand forecasting information for the SO [18] for demand >5MW and generators >1MW. In future, greater resolution and integration of forecasting may be required and closer to real-time for all system operators and new parties e.g. smart cities. Code changes are likely to involve a range of stakeholders and could be quite complex to optimise for a whole-systems approach [4]. There is no balancing code at distribution level at present.

The cost of developing such advanced modelling capability is likely to be a significant outlay. It is not clear who would lead/contribute to development. Forecasting capabilities may be challenging for new parties particularly with little historic data. There is limited existing advanced real-time forecasting and modelling experience outside SO [10], [4].

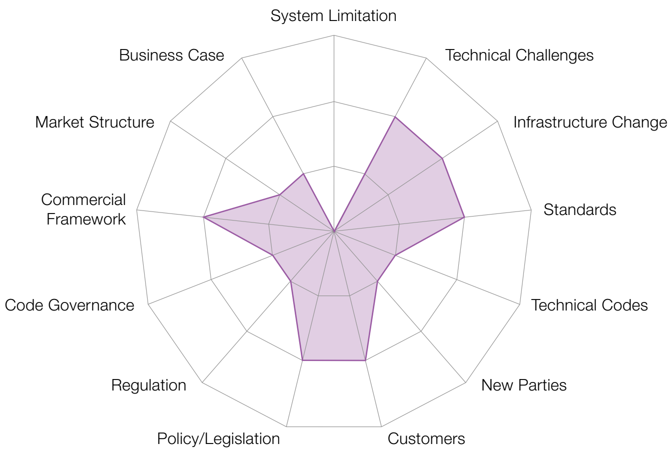


Consequences

As this function is in the operational timeframe, significant consequences exist for operational costs. This is due to the risk of inaccurate forecasting and modelling resulting in inefficient procurement of systems services from the market. There are also implications for accommodation of low carbon generation and demand if the value of flexibility services is not able to be more fully realised through improved forecasting of intermittent renewable generation in particular.

If system services procured are not aligned with system requirements due to inadequate forecasting and modelling then there are serious implications for system stability, security of supply and reliability.

C5 Identify available generation, other energy resources and ancillary services and associated operational restrictions in real time.

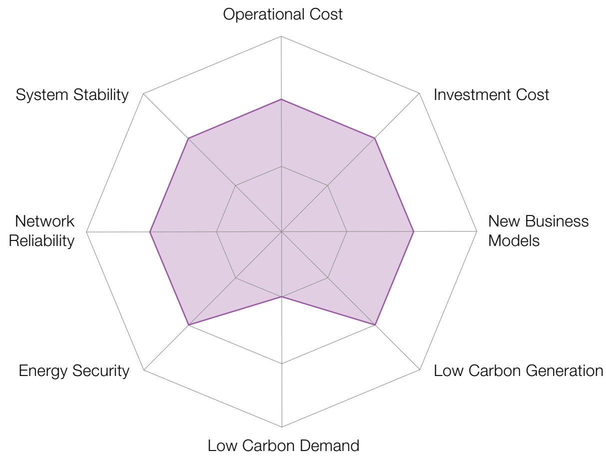


Implementation barriers
A significant amount of embedded generation and demand is not visible in real-time particularly at LV level. This includes operators of DER arrangements and ancillary/flexibility services. Also, no party has visibility of other parties' arrangements. Network monitoring at lower voltage levels is also limited, so detection of any network constraints is via substations and feeder incomers only.

Existing network communications and IT hardware and software is not sophisticated enough to support the identification of DER and operational restrictions in real-time, requiring enhancements to efficiently manage and analyse large volumes of data and increased communications bandwidth. For example, the TSO could dispatch demand turn-up in an area where a temporary network constraint existed; and similarly a DNO could dispatch DER to ease network constraints without the SO's knowledge, meaning it was no longer available to provide a reserve or ancillary service to support system balancing. The existing regulatory framework does not provide clarity on roles and responsibilities for co-ordination and sharing of this information. There are several innovation projects exploring how this might work in practice [27], [19].

Lack of industry standards for cyber security and data protection and lack of interoperability of HEMS [23] (i.e. that limits controllability of domestic load to less than what is reported as available) could also make it challenging to identify available DER 'beyond the meter' [24].

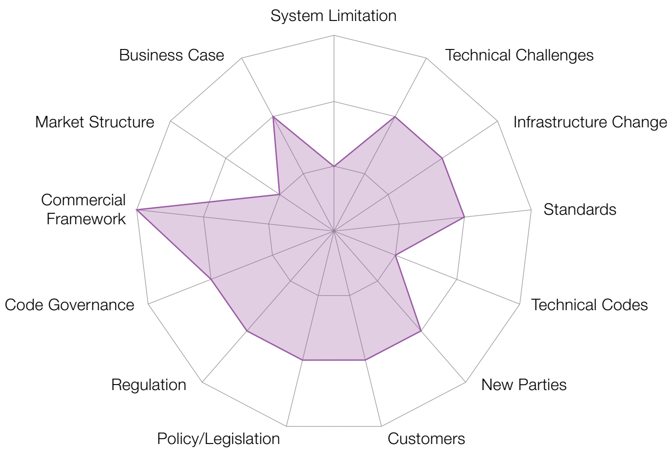
Increased real-time network metering or monitoring may be required at lower voltage levels to help identify network constraints, particularly due to conflicts in co-ordination of system actions. This can be costly at high volume and the cost-benefit case would need to be carefully considered to ensure value for money.



Consequences
Lack of visibility of DER availability may result in higher operational and investment costs due to over-procurement of system services. With the full value of flexibility from low carbon generation and demand not able to be realised, this may reduce accommodation on the system.

Potential conflicts may occur due to lack of visibility of available DER, impacting security of supply and stability. Also, if operational restrictions are not able to be identified, this could have significant consequences for system reliability.

C6 Collate and distribute information throughout the power sector on the performance of demand, generation, other energy resources and ancillary services in order to enable settlement.

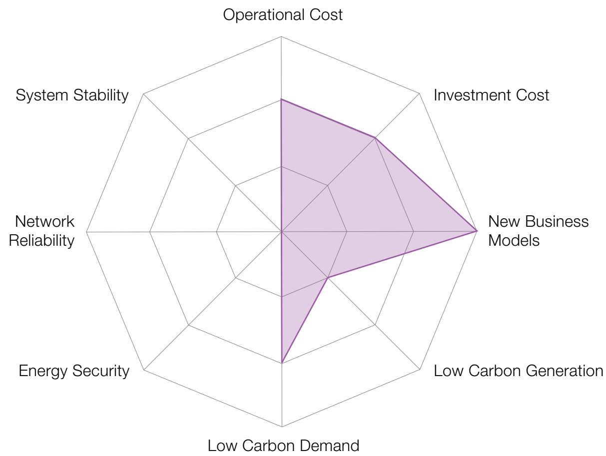


Implementation barriers

Collection and dissemination of information throughout the power sector may require significant monitoring and communication infrastructure [25], [10]. There are likely to be associated technical challenges in ensuring compatibility of systems (standards/data protocols) across the industry and standardisation on systems/tools for distribution of information [10], [26], [27]. Existing standards for data privacy/security for example require enhancement [26].

The regulatory framework limits access to and use of data [28], [29]. Roles and responsibility for collation and distribution of data and protection of confidentiality are not clear [26]. For example, integrated methodologies are required between SO/TNO/DSO to avoid needless duplication and data delays. A hierarchy of data collection, processing and consolidation is required.

Changes may be required to the Balancing and Settlement Code, and potentially to protect customer information. There is no balancing code at distribution level [18] and this could limit procurement of local balancing services and thus improved understanding of more granular system services. Potentially, there could be a large increase in new players requesting access to power sector data and it could be challenging to vet/accredit new participants. The confidentiality of customers' data also needs to be protected.

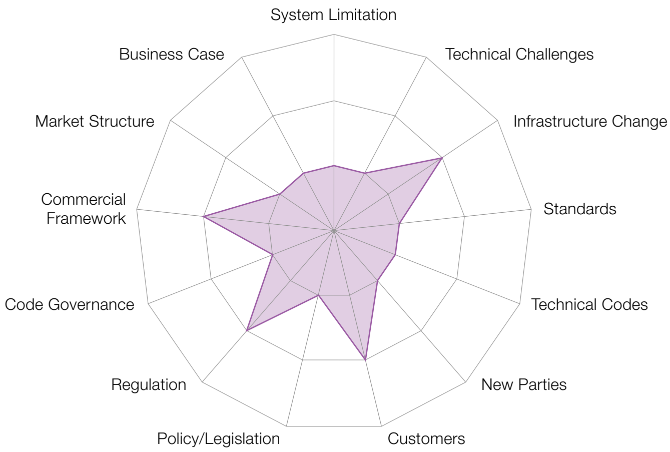


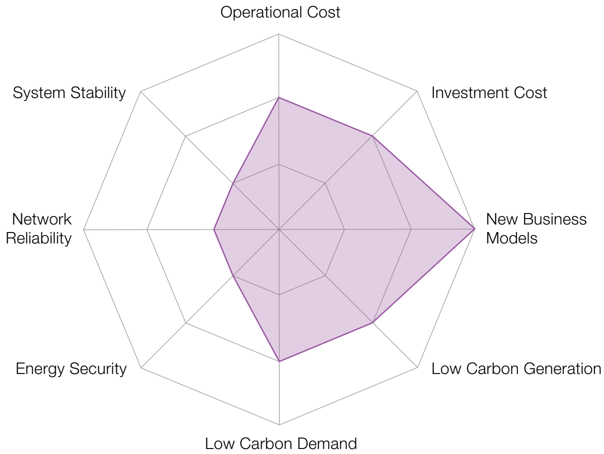
Consequences

Lack of visibility of DER and ancillary services performance across the power sector may result in higher operational costs due to over-procurement of system services. Investment costs may also be higher than necessary as flexibility is not fully utilised due to uncertainty in performance. This could lead to under-valuation of network flexibility and thus impediments to new business models.

If the full value of flexibility from low carbon generation and demand is not able to be realised due to lack of sector-wide understanding of performance, and thus suitability and value for various system services; this may reduce accommodation on the system.

C7 Monitor and settle the delivery of contracted demand, generation, other energy resources and ancillary services.





Implementation barriers

Implementation barriers mainly relate to contracted demand at lower voltage levels. Completion of the smart meter roll out, data communications and associated settlement systems are required to enable half-hourly settlement for all demand. The smart meter roll out has been slower than planned [31], [32].

The existing regulatory framework does not extend to half-hourly settlement to all customers and the process for changing customer measurement class is complex [33]. However, this should be resolved once the smart meter roll out is complete.

Existing contracts are generally not on the basis of half-hourly settlements that support flexible tariffs [29] and changes will be needed to settlement systems (including supplier billing systems) to enable full half-hourly settlement with associated costs.

Consequences

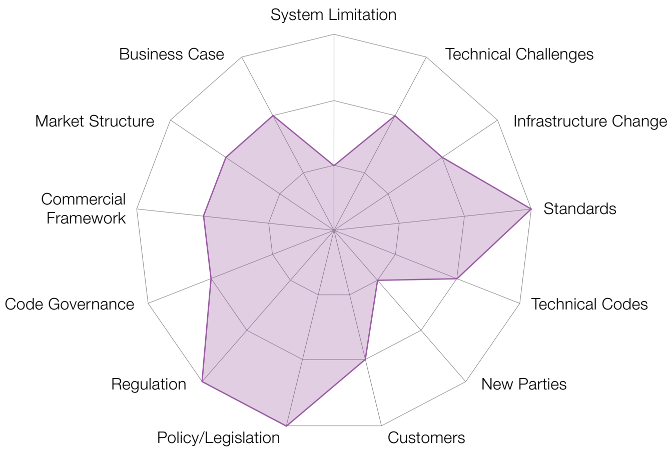
Lack of transition to half-hourly settlement for example could hinder use of price signals e.g. to shift demand and manage peaks. This could impede the emergence of new business models including new (aggregated) flexibility services.

Decarbonisation may be slowed due to inability to fully capture system value from low carbon demand and generation e.g. through demand side response or frequency system services.

This may also result in inefficient investment and operational costs as existing customer and network assets are not fully utilised.

4.5 Implement smart grid

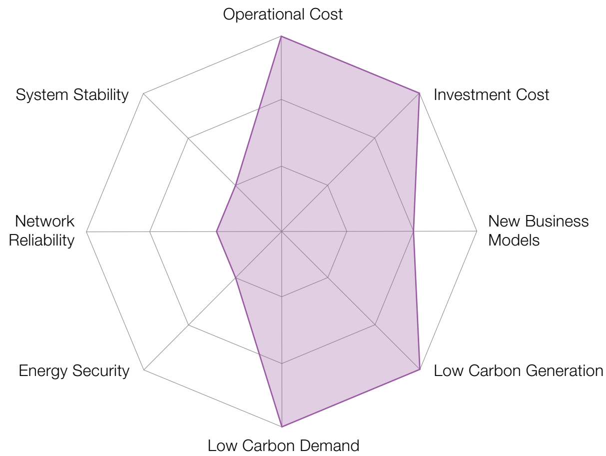
D1 Use appropriate approaches, including smart technologies, to maximise the capacity of the power system to accommodate the connection and integration of new demand, generation, other energy resources and ancillary services.



Implementation barriers

There is policy uncertainty around future (distributed) low carbon demand and generation and this affects the role of flexible DER in maximising the capacity of the power system. There is also a lack of clear signals for cross-vector policy [14]. The existing regulatory framework is not appropriate for new roles and responsibilities of stakeholders that might be needed to maximise network capacity e.g. it does not define the roles, responsibilities and obligations of a DSO and co-ordination with TSO and other DSOs, or multi-vector co-ordination [10], [11]. Also, electricity and gas are regulated separately and independently with no regulatory incentive to co-ordinate network capacity.

Greater co-ordination between system operators and across different energy vectors to maximise capacity is not currently reflected in grid codes and standards. Technical codes do not yet address capacity that may be available from other vectors/sectors and how this would be managed and co-ordinated efficiently [6]. Also, planning standards are still relatively deterministic and do not currently capture fully the capacity that could be gained through a more probabilistic consideration of network capacity [6]. Code changes may be required for the D Code and P2 for example, involving a large number of stakeholders and complex impact assessments. P2/6 is currently under review [6]. There are a number of smart technologies deployed but many are still in the R&D phase (low TRL) or only rolled out in limited areas [34]. Also, existing modelling and forecasting capability and skills are not at the level of sophistication required to capture full value to the network of DER and flexibility services e.g. lack of a whole-systems approach across the systems chain in planning and operational horizon [2]. Commercial arrangements and market structure for flexibility services and smart solutions such as ANM schemes are currently bespoke. For example, ANM is based on reduced capital cost of connection rather than valuation of a specific flexibility service [20]. If DSR causes more complexity in the energy market, this could have a particularly negative impact on vulnerable consumers [3]. Generally, lack of customer uptake of DSR services could be a barrier.

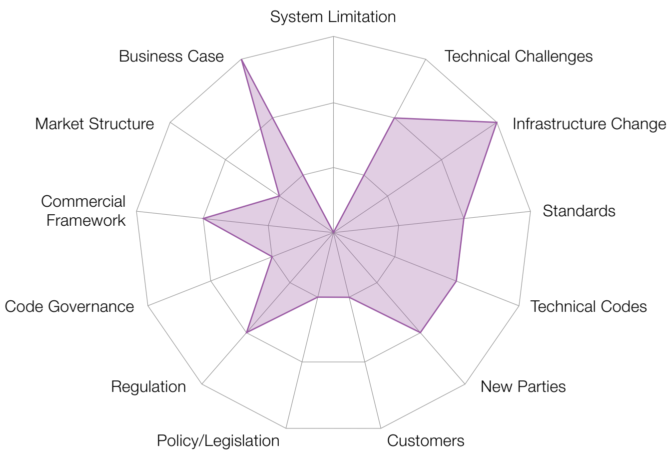


Consequences

If the capacity of the system is not maximised through optimising the contribution of smart solutions (including DER) then it logically follows that investment costs will be higher. Capacity solutions are likely to be less flexible and modular, resulting in higher risk of underutilised capacity and stranded assets. Operational costs could also increase for constraint management for example if smart technologies are not available to fully enable distributed generation and demand side response. This could impact decarbonisation as low carbon generation and demand will reduce network capacity without also providing controllability for capacity management with synergies through multi-vector interaction not exploited. Also, lack of a more sophisticated and transparent market and commercial contracts for capacity constraint services for example may result in investment uncertainty.

4.6 Necessary operator interventions

E1 Ensure that monitoring is in place to support the use of active system management.

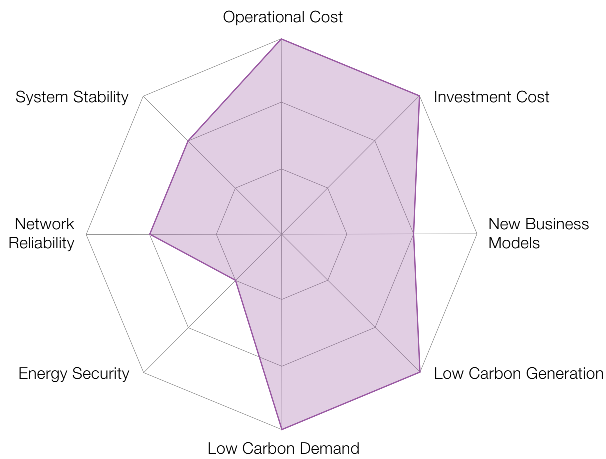


Implementation barriers

Low voltage networks are extensive, with approximately 400,000 km of circuit across GB. Deploying monitoring on all these assets is likely to be very expensive [35], with an anticipated cost of £100,000 for 100 sub-stations [36]. With around half a million secondary sub-stations in GB, the total cost would likely be billions of pounds.

Even without full coverage, monitoring will therefore require a significant roll out of new infrastructure, including IT to manage data and provide links with other internal systems [36] as well as monitoring devices themselves. Integrating this [37] and finding low cost solutions will be technically challenging – for example, development of a low cost remotely interrogated demand profile data logger would be beneficial [36], [38]. Changes to codes and standards may be required in order to promote standardisation and interoperability between different systems and devices.

Another option would be for future utilities to access data from smart meters. This would be subject to regulatory scrutiny – DNOs already have a stringent process which DNOs must adhere to if they want to access smart meter half-hourly consumption data [39]. In the future, a DSO may need to access (aggregated) smart meter data nearer to real-time (to support active management); however this would be very technically challenging and potentially expensive. Monitoring solutions will need to protect customer anonymity and will be subject to strict data security and privacy requirements, as has been the case for smart metering [40]. The emergence of new parties that might operate private networks, such as smart cities, may complicate monitoring e.g. if network companies are not able to observe what is happening on these networks.

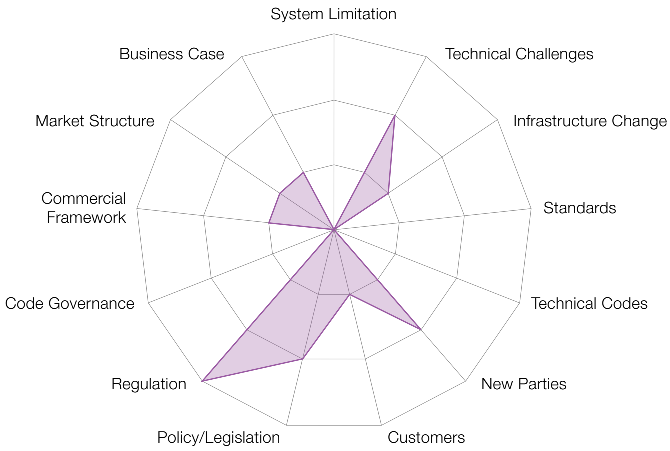


Consequences

Without monitoring to support active management of the system, it is likely that further investment would be required to accommodate growth in demand and generation at LV. This might also lead to inefficiencies in how the system is operated (e.g. through high outage costs or inefficient ANM actions). Some new business models (e.g. flexibility service provision) depend on the widespread deployment of ANM and monitoring at LV.

Lack of visibility of LV networks would probably impede the ability of the system to accommodate greater deployments of microgeneration or widespread electrification of heat and transport. If DNOs do not have sufficient visibility of the impacts which this is having, then solutions to address it are likely to be inefficient. Ultimately, this could put the reliability and stability of the system at risk, e.g. large and unobserved heat pump loads could cause LV feeder fuses to blow and/or voltage levels to drop below appliance compatibility levels. Without monitoring, diagnosing this issue would require examination of aggregated half-hourly profiles (or voltages) from smart meter data.

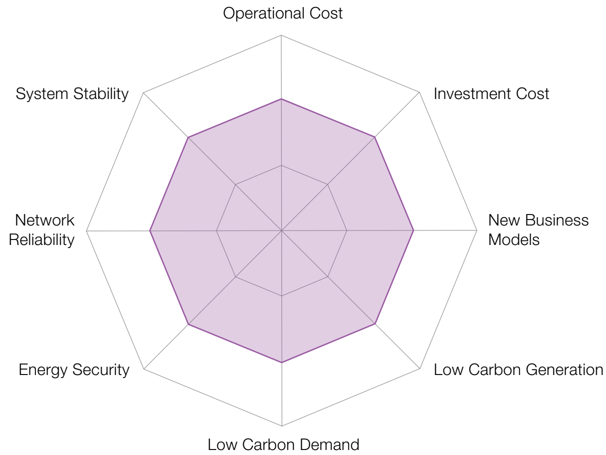
E2 Review the power sector's developing operational characteristics to validate the assumptions made during the investment planning process.



Implementation barriers

Changes in the system can manifest suddenly – for example the extent of the boom in solar PV installations in recent years was larger than many had expected. Policy changes can also rapidly affect the operation of the power system – one of the goals of the mid-period review within RIIO is to determine whether policy changes have affected delivery against outputs [41]. Therefore, there could be a requirement for frequent reviews, particularly if the system is required to adapt quickly if any changes are identified (e.g. through F1).

However, this is at odds with the need for longer term stability and certainty in regulation. For example, RIIO uses an eight-year regulatory cycle. Uncertainty mechanisms are defined at the outset of the price control and there is the opportunity for a mid-period review. This may not be appropriate for the scale and pace of change which could occur in the future and might limit the ability of the system to accommodate new business models and new parties if these fundamentally change the operational characteristics of the system or if they rely on different investments. In addition, it may be technically challenging to adapt analytic and modelling capabilities to accommodate changes in the system in order to validate assumptions. For example, new parties could emerge that behave in a way which is not accounted for in existing models.

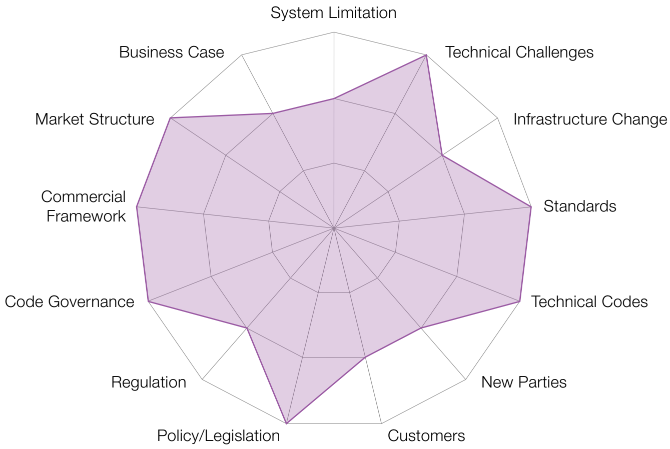


Consequences

Failure to implement this function could have consequences across the energy trilemma, as failure to account for changing operational characteristics in assumptions used for planning could impact the system in many ways. This might result in inefficient investment plans being progressed, or inappropriate operational practices continuing to be used. Ultimately, it may prove challenging for new business models to be implemented if there is not a good understanding across the sector of how these new business models will affect the system and required investment. If plans for deployment of low carbon generation and demand change, it may prove difficult to accommodate this if this change is not identified and considered in investment planning.

Operational characteristics could change in a way that, if not accounted for in ongoing system planning, might affect the investment to secure security of supply, reliability and stability of the system.

E3 Provide the capability to observe energy resources across the whole-system and mechanisms for intervention.

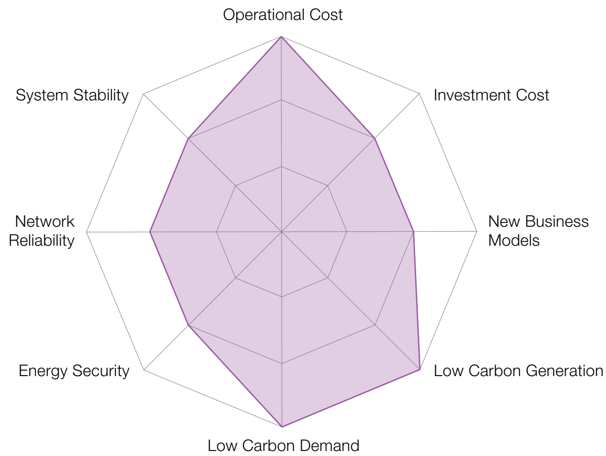


Implementation barriers

There is currently limited monitoring and controllability of DER [2]. There may be complex, dynamic control interactions with large volumes of DER and multi-vector systems in future. Communications infrastructure and advanced information technology and appropriate standards required for widespread automation and dispatch of DER (and IoT) is not yet available/implemented for example [10].

DNOs procure limited system services such as DSR for network constraint management but there is little experience of modelling tools such as Dynamic Dispatch Models outside the SO that would enable local and regional dispatch in a decentralised power system, and little integration of other energy vectors and new parties such as smart cities. Elements of this are being explored in TDi [27] which is developing and trialling an innovative control platform to predict dispatch and maximise dynamic reactive power response from DER to support the transmission system. Greater co-ordination between system operators and across different energy vectors to observe and control energy resources, taking a whole system approach, is not currently reflected in grid codes [6].

There is policy uncertainty around the role and levels of future (distributed) low carbon demand and generation which affects the observability of flexible DER for example, and a lack of clear signals for cross-vector policy [14]. Also, the existing regulatory framework is not appropriate for roles and responsibilities of stakeholders that might be involved in a more decentralised and multi-vector energy system [10], [11]. Without a clear regulatory and commercial framework, new parties may not have sufficient investment certainty. This may also need to address availability of markets for flexibility provision to enable the aggregation of small-scale demand side response resources, the balancing between national and local value streams, and the harmonisation between system cost minimising solutions and individual market participants' objectives [2].

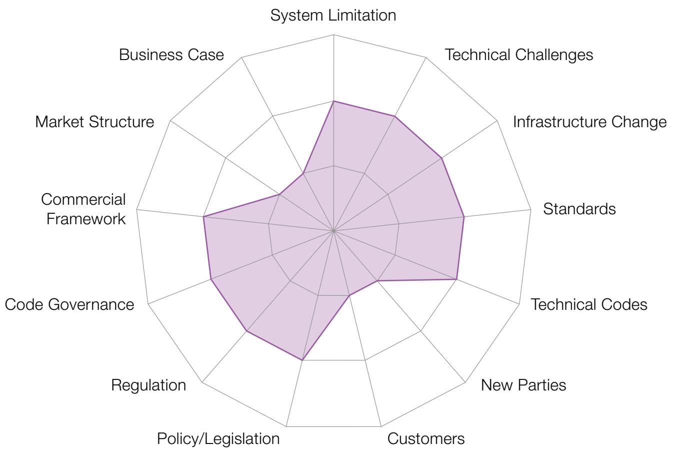


Consequences

Without observability of DER and the ability to carry out interventions, operational costs could be significantly impacted as system services are over-procured and/or more costly. There is also a significant risk of multiple parties using DER in conflicting ways. Limited capability of DER to be observed and to contribute to the system may also have consequences for low carbon generation and demand as the system becomes stressed due to uptake. This will likely result in increased investment costs also.

Without controllability for system interventions, new business models for DER may not stack up e.g. localised system services for DSO.

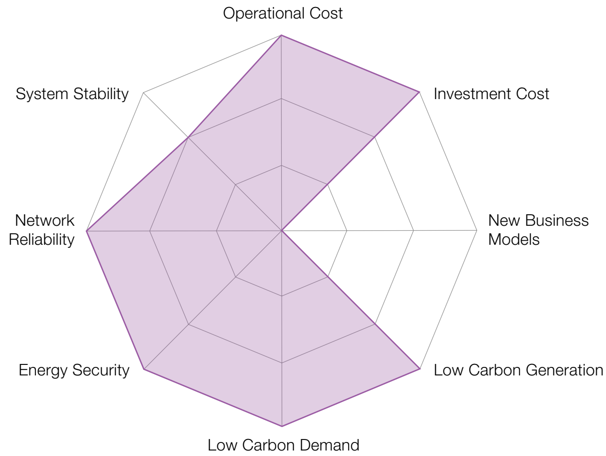
E4 Identify by modelling and simulation constraints arising from credible events/faults, and plan remedial action.



Implementation barriers

The level of modelling and forecasting sophistication required to identify wide-scale network constraints arising from large volumes of intermittent, weather dependent generation and low carbon demand is not currently available. There is a lack of a whole-systems approach in modelling systems in the planning and operational horizon [2] and little integration between real-time power system models and dispatch/market models. Advanced modelling will need to be integrated with control functions and software, specifically at distribution level [10] both for centralised and decentralised systems.

Existing remedial actions are limited in the range of actions that can be provided in response to an event, specifically at distribution network level: e.g. there is no widespread automated demand side management contracted at distribution level currently. This makes it challenging to verify behaviour of remedial actions provided by new parties for modelling of a range of scenarios. Existing network standards and technical codes do not fully reflect the potential of a wide range of remedial actions e.g. demand side management, to support efficient network operation [6]. Lack of access to sensitive or historic data may be a barrier for modelling by new parties.

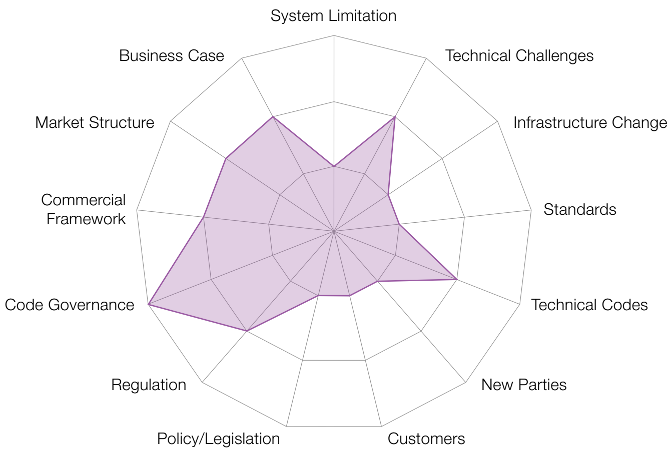


Consequences

Without being able to accurately model network constraints, the planning (and verification of behaviour) of remedial actions is less likely to be effective. This could result in higher operational costs due to system services being over-procured. Investment in network capacity may also increase more than necessary due to increased uncertainty of actual constraints.

There is a significant risk for system security in particular if remedial actions applied to the network are based on modelling that does not fully consider complex flows and actions on a whole-system basis. Reliability and system stability will also be impacted.

E5 Monitor the effectiveness of, and execute as required, remedial action (including market mechanisms and smart capabilities for the delivery of demand control, generation constraint and other actions) in response to all events/faults.

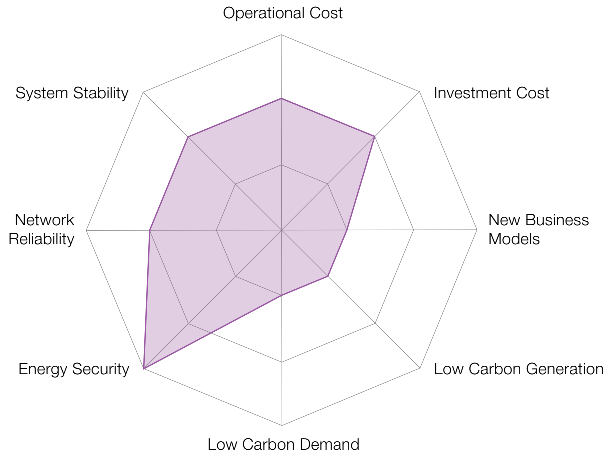


Implementation barriers
There is a number of commercial barriers for executing remedial actions in response to events/faults. These include the limited contribution of diverse low carbon flexibility services in existing commercial frameworks e.g. energy storage [28] and limited market structure for procurement of system services at distribution level e.g. a 'reserve capacity' service (based on availability and utilisation payments).

The business case for structuring a range of remedial (balancing) actions to maximise value to consumers is uncertain e.g. dispatch and prioritisation at distribution level [20]. The development of ancillary services at distribution level would require significant code changes to the operational code, balancing code and CUSC [20], [55].

Remedial actions sourced from DER across a range of voltage levels is likely to be technically challenging to integrate in the control room leading to potential conflicts with network availability or capabilities [20].

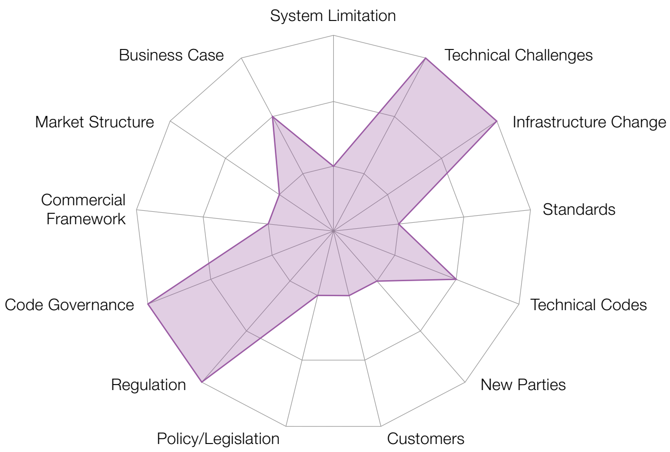
The UK Power Networks Smarter Network Storage innovation project explored the use of energy storage to manage network constraint (P2/6 compliance) issues. Other services such as STOR and Frequency Response were provided on top of this to increase the revenue stream and hence enhance the business case. Learning outcomes should help to reduce some of the barriers described above [42].



Consequences
Without being able to monitor and prove the effectiveness of remedial actions using DER, operational costs may increase due to system services being over-procured. Investment in network capacity may increase more than necessary to accommodate growth of low carbon generation and demand.

There is a risk for system security and reliability if remedial actions, particularly those based on DER, cannot be monitored to prove effective delivery and inform volumes for procurement.

E6 Co-ordinate demand, generation, other energy resources and ancillary services within the power system to deliver system security and maximise the use of low carbon generation at optimal overall cost.

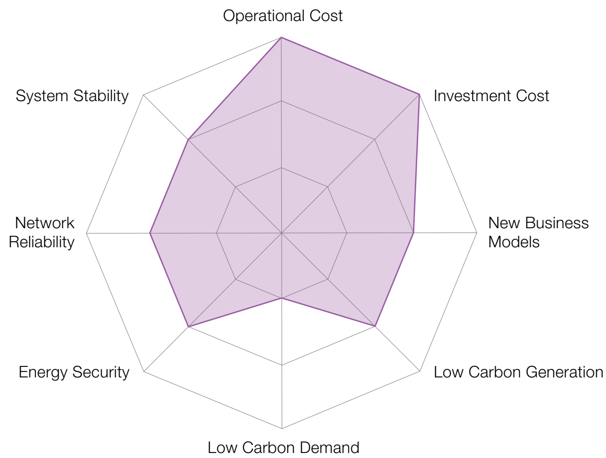


Implementation barriers

Co-ordination of DER and ancillary services across voltage levels and between system operators, for example, is only being trialled in innovation projects to date [27], [43], [44]. Future power flows are likely to be complex with a higher volume of service providers and greater number of interfaces. More advanced optimisation tools, software and data management methods may be required [10] to maximise use of low carbon generation at least cost.

Control strategies particularly at distribution network level (or smart city) are not robust enough for future complex control interactions with a large volume of DER. This will require more advanced operational control [27], [10].

In a regulatory context, definition of new roles, responsibilities and obligations of various stakeholders e.g. DSOs, does not exist. This would support further development of a co-ordination framework which is being explored in [27]. Existing industry code does not capture the increased co-ordination required between system operators and with service providers e.g. significant code changes and additions are likely required to facilitate this such as a balancing code at distribution level and changes to the CUSC [10], [4], [18], [9].



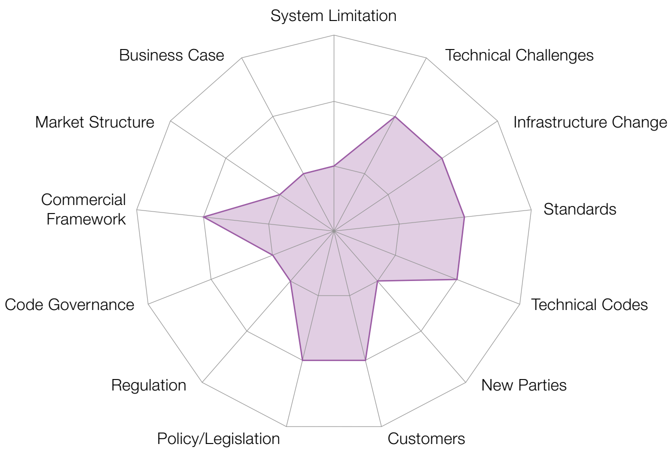
Consequences

A lack of co-ordination of DER between system operators, service providers and other parties is likely to result in inefficient system services procurement and thus increased operational costs e.g. over-procurement, losses, curtailment costs etc. Higher investment in network capacity may also be required to manage thermal constraints or voltage for example.

Increased uncertainty due to lack of co-ordination [6] could deter the development and deployment of new business models for network services and particularly low carbon generation.

There may be implications for system security such as lack of availability or conflicts of system services leading to low frequency demand disconnection and reduced reliability for example.

E7 Provide monitoring and control of those parts of the system under active management, including network assets, demand, generation and other energy resources and ancillary services.

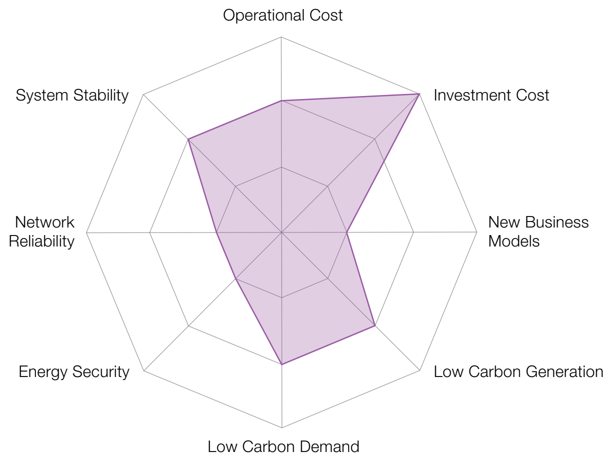


Implementation barriers

The most significant barriers for this function relate to technical challenges for real-time monitoring and control. Traditionally, control infrastructure has been centralised and there is very limited monitoring at lower voltage levels with controllable network points generally MV and HV circuit breakers and transformer tap-changers only [10], [20]. This is reflected in technical codes in terms of interaction with embedded generators or demand [18] and the lack of a balancing code at distribution level.

Future monitoring and control may become more highly distributed and autonomous to help manage the increasing complexity of power flows and control signals across the system. This will be limited without advanced sensors, communication and information technology and will also need increased standardisation to support interoperability, re-configurability and controllability and competition in supply.

Whilst a DNO can support actively managed networks, the existing regulatory framework does not define roles and responsibilities of a DSO for example, to undertake local balancing and network constraint management based on actively managed networks [10], [11]. Without this, there is potential for control conflicts between DSO and TSO.

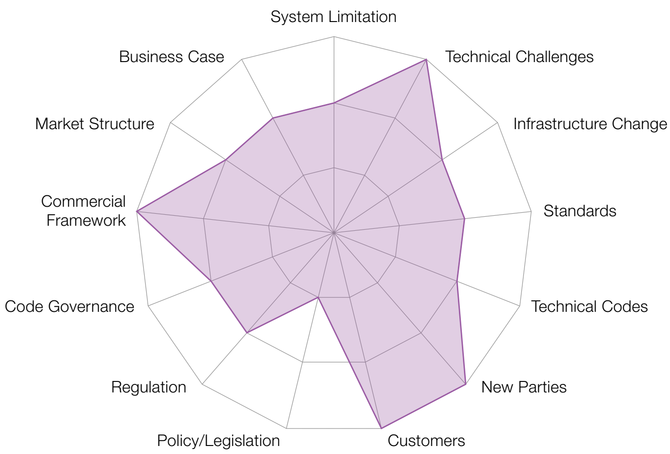


Consequences

Without sufficient monitoring and control of network assets and DER, it may not be possible to fully unlock capacity benefits, resulting in higher network investment costs and reduced value of low carbon generation and demand to the system. ANM has been instrumental in accelerating integration of renewables to date by helping to manage areas of load congestion cost-effectively. Reduced control of low carbon DER could result in the operation of costly fossil fuel plants during system peak and less optimisation across the system.

Without effective monitoring and control of networks under active management, and visibility of active management actions between parties, system stability may be compromised due to system operator conflicts for example.

E8 Provide automated and secure management of demand, generation, other offered energy resources and ancillary services, including Smart Appliances, HEMS and BEMS.

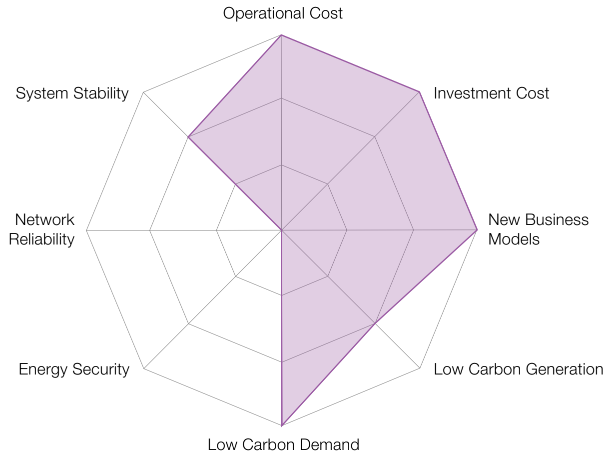


Implementation barriers

The technical functionality and standardisation of DER is limited to date. For example, there is a lack of machine learning capability between network and DER control systems [45] which could result in detrimental control interactions and there are interoperability issues for HEMS [23] e.g. smart appliances. Also, industry standards on consumer data protection and cyber security for 'beyond the meter' DER automation are not sufficient [24]. Infrastructure for communications, and associated costs, will be required for widespread automation of DER (and the IoT) [12]. The cost-benefit case for HEMS for example is not so compelling without access to flexible tariffs options.

Existing commercial frameworks limit the contribution of diverse automated flexibility services such as energy storage due to short contract tenures [8]. The market structure is also not fit-for-purpose for diverse flexibility providers [8] e.g. based on a centralised approach for power balancing.

Societal barriers include the exposure of new parties to significant upfront cost and technical risks under the traditional licensed supplier model [24]. There could also be lack of value for vulnerable customers and smaller businesses who may not be able to access value from smart appliances, HEMS, BEMS etc. and so may be unable to benefit from more personalised tariffs [24].



Consequences

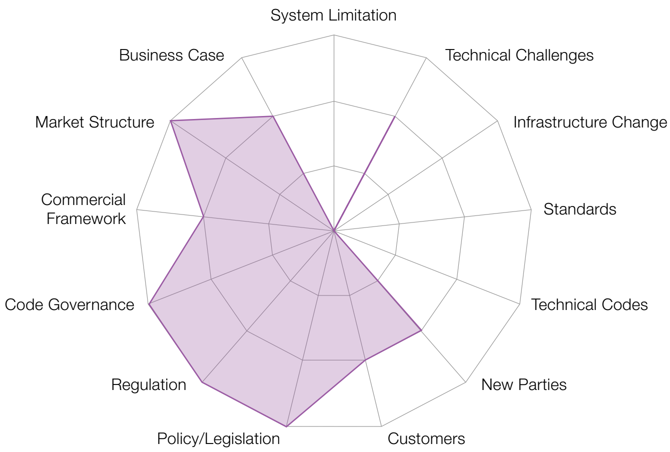
With fewer sources of flexibility and potential under-utilisation of available sources, the cost of operation is likely to be higher. There may not be significant buy-in from demand (particularly domestic consumers) without automation.

Investment to meet peak loading is likely to be higher without automated load optimisation services to provide constraint when required.

New business models built around HEMS, BEMS, and other automations are less likely to succeed if the system does not have the ability to utilise them. This could affect the uptake of low carbon demand whereas larger scale generation is more likely to be able to self-dispatch and manually respond to signals/markets for management.

4.7 Monitor and mitigate trends/emerging risks

F1 Enable the power sector to manage necessary changes across the sector when faced with new developments or changes to its objectives and operating environment.

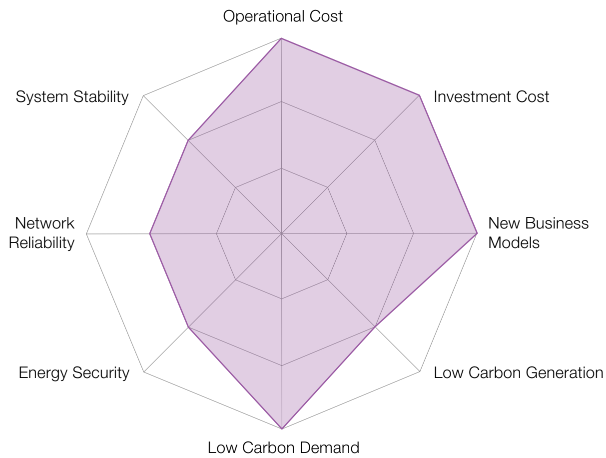


Implementation barriers

Implementation will require enhancement of the technical resources of industry oversight parties such as BEIS or Ofgem. The CMA has noted that Ofgem's technical resources are constrained, which limits their ability to respond to code issues.

Wholesale changes to sector governance would be very difficult to implement through existing sector governance arrangements. Ofgem has reviewed governance arrangements before and made some process changes (e.g. the introduction of the Significant Code Review) but their ability to effect widespread changes is limited. For example, the 'reset' proposed by the CMA is a 'substantial reform package' [46] but is arguably smaller in scope than the change envisaged in FPSA. Existing regulatory arrangements may inhibit flexibility in the sector – e.g. the eight-year regulatory period may need to be shorter, or there may be a need for more mid-term checks. Greater strategic policy guidance in industry may be required and implementation of this function would require significant legislative and policy effort.

Existing commercial arrangements and market structure may impede the sector becoming more flexible, as there is significant inertia [4] behind existing arrangements. For example, it has been argued that BETTA has historically favoured vertical integration of supply and demand and significant reforms have been required to promote independent suppliers and new entrants [48]. The need to account for a wide range of stakeholder views, which has historically been achieved through an iterative working group and consultation process, may limit the ability for change to be implemented rapidly and flexibly. New parties, who may not have historically been involved in the sector, will also need to be identified and engaged in change management.

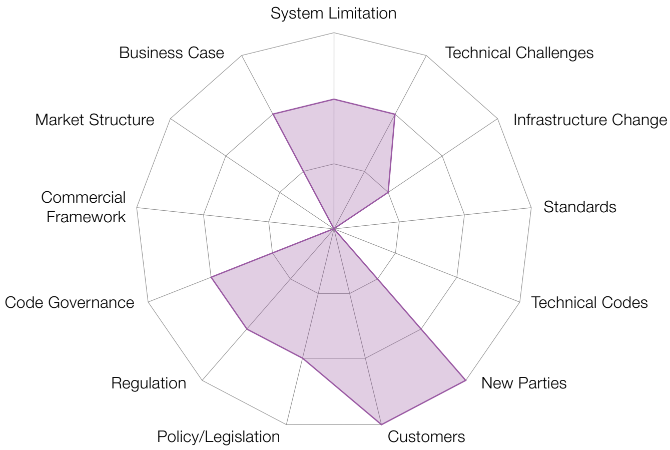


Consequences

It is likely that the sector's high emphasis on security of supply would continue, but the ability of the system to manage operability risks would be limited, which may affect the security, reliability or stability of the system.

If the sector cannot efficiently manage change, then the overall cost of investing in and operating the system is likely to be affected (e.g. through 'over-engineering' network security or needing to constrain renewable generation). New parties may find it challenging to implement innovative business models if these depend on changes to the way the system is managed. Decarbonisation of generation would probably continue, albeit at a slower pace. Wider electrification of heat and transport may be affected.

F2 Identify, counter and learn from threats to operability of the power system from all parts of the power sector both above and beyond the meter.

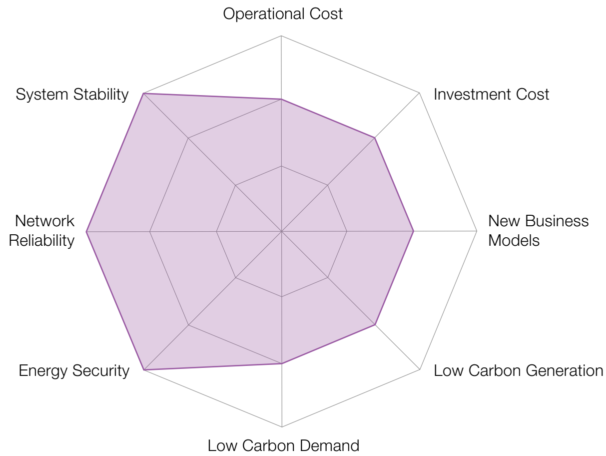


Implementation barriers

The main barrier to the implementation of this function is the societal challenge associated with capturing a whole-system view of operability threats and responding to these, particularly regarding threats that might emerge from beyond the meter. For example, the SO currently has limited visibility of what happens below the transmission interface [1]. The DNO has limited visibility and control of real-time network behaviour at lower voltage levels. Countering threats may be technically very challenging as these could be wide ranging, for example: from managing decreases in inertia and increasing RoCoF to increasing system load peaks and reduction in reactive power at the transmission interface.

Governance could be a barrier to implementation. Policy uncertainty could make identifying and countering threats more challenging, and regulation and code governance could limit the ability of the industry to respond quickly to counter threats [6]. For example, the introduction of new ancillary services that help to better capture the value of system flexibility to system operability or longer-term contracts for services may require changes to the way in which the SO incentives currently work [47] – the current two-year incentive period for the SO disincentivises long-term contracts from being offered and most balancing services are contracted on a relatively short-term basis. This might drive up financing costs for service providers.

New parties that have not traditionally been part of the power sector will need to be engaged e.g. other energy sectors, local and regional councils, smart cities etc., and their input and requirements will need to be balanced with those of a wide range of existing stakeholders. Collaboration between multiple parties will need to be encouraged e.g. through the regulatory framework.



Consequences

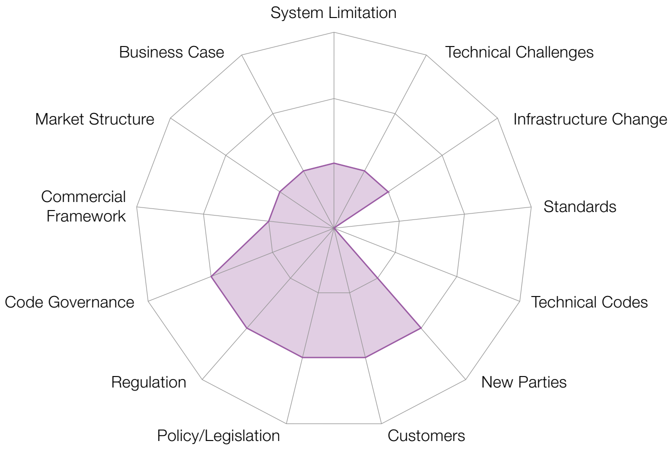
Failure to deliver this function is likely to have impacts across the trilemma.

Without foresight of threats, utilities may respond to them in inefficient ways for example by building additional network assets to help manage issues or by not optimising dispatch of system services.

Failure to identify threats could also affect the ability of the system to accommodate low carbon generation and low carbon demand, for example the system may have to limit the amount of intermittent generation on the system at any one time.

In particular, failure to identify operability threats across the whole power system could pose a significant risk to overall security and reliability of the electrical supply and could affect the stability of the system.

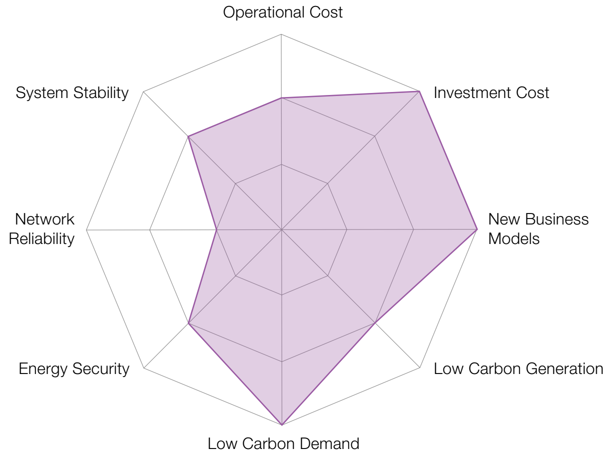
F3 Monitor the impact of customer behavioural changes on system operability and propose solutions to resulting operability issues as necessary.



Implementation barriers

Failing to engage effectively with new parties and existing customers is likely to be the key impediment to implementation of this function. New parties may operate 'autonomously' from the system, in response to dynamic incentives, weather variation, or other price signals e.g. in a local energy market. Techniques for modelling the behaviour of autonomous parties, which might include smart cities or local community energy schemes, are not currently well developed [21], [2]. There is currently limited knowledge of what drives consumer interactions with smart grids (cost, climate, convenience, technology, incentives etc.) [24], so determining potential system impacts would be challenging.

A change to the regulatory framework may be required in order to define the roles and responsibilities associated with carrying out this function, which could be similar to the role of the NETSO in completing the Network Options Appraisal. The framework of code governance may not be appropriate for allowing credible solutions to be proposed promptly [6].



Consequences

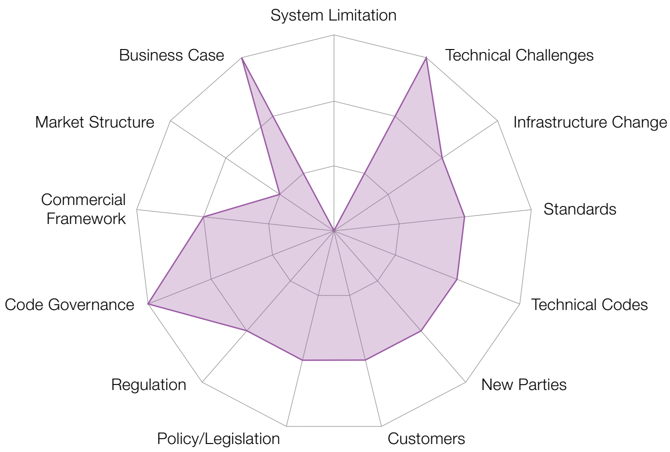
Failure to implement this function would likely increase the total cost of the power system, and potentially affect decarbonisation efforts, with lower consequences for security.

As well as potentially driving inefficient costs, lack of understanding about consumer needs and behaviour could impede the development of new business models, as the system may not work in a way that supports these.

This could in turn affect the deployment of low carbon technologies by smaller consumers, which would particularly affect the ability of the system to decarbonise heat and transport.

It is likely that the system would continue to operate securely based on a broader understanding of power system threats, but there would be a risk of reduced security and stability if certain behaviours aren't well understood such as heat demand pick-up during cold snaps or the dynamics of uniform responses to price signals (e.g. a step change in demand in response to time of use tariffs).

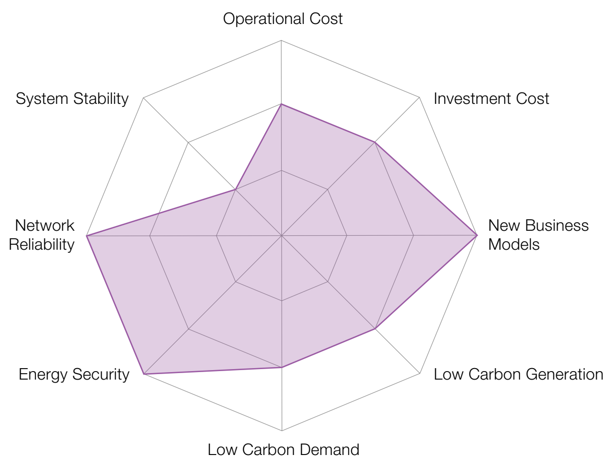
F4 Identify and protect, on an ongoing basis, against cyber security threats to the operability of the power system which originate from inside and outside the power sector. Detect and respond to existing, new and unforeseen cyber security incidents promptly as required.



Implementation barriers

Retrofitting cyber security capability into a system that has traditionally not been designed with cyber security in mind is likely to be very technically challenging due to the physical extent of the electrical network and the variation in asset types. There are typically poor records about software and existing assets, specifically at lower voltage levels, that may need to be upgraded or replaced where cyber security capability has not been designed in e.g. where public communications systems are used. Also, wider connection of actively managed DERs that may not have appropriate cyber security capability will pose a risk for decentralised and distributed assets. Future codes and standards will need to reflect cyber security requirement. The complexity of existing ISO and IEC standards may mean that an overarching framework of standards is required [49]. Smart appliances including thermostats and EVs (Artificial Intelligence devices generally) will need to account for cyber security risks, particularly those that are controlled as part of HEMS or BEMS. This might particularly impact new parties such as smart cities which may rely on sophisticated IT infrastructure for their operation.

Outside of Critical National Infrastructure, cyber security regulations in the UK are focused on data protection rather than network security, with wider requirements addressed through guidance and best practice [50]. Further regulations may be needed to encourage or incentivise necessary actions to address threats to the whole system which emerge beyond the meter e.g. a cyber-attack that unexpectedly brought online several million internet-controlled heat pumps could cause a system emergency. This may be addressed through a separate review which is understood to currently be in progress. The establishment by the Government of the National Cyber Security Centre [51] and the recent publication of the National Cyber Security Strategy 2016 to 2021 [52] are positive steps towards enabling this function. Regulation and incentives may help the business case for cyber security investments which can be challenging, as the business case generally relies on demonstrating a positive NPV [53] and this may be difficult to achieve for high impact/low probability events. The existing framework of industry governance may not be agile or flexible [4] enough to allow prompt adoption of cyber security measures within codes e.g. this might include cyber security requirements in the Grid Code for communications and control devices connected beyond the meter.



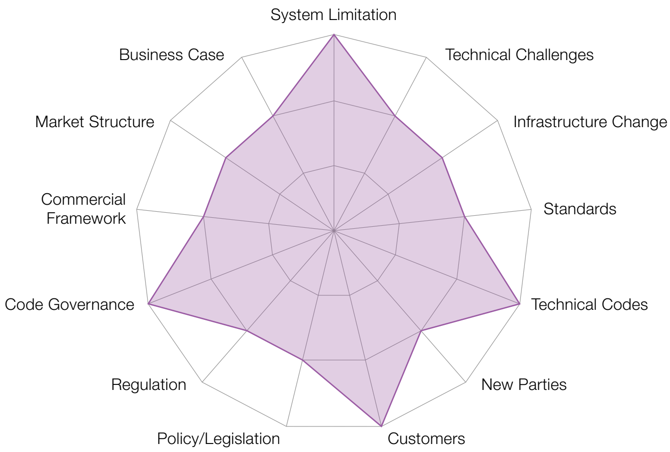
Consequences

Failure to implement this function could put the overall reliability and security of the network at risk to a cyber security threat e.g. by compromising systems which are essential to the control of the network or affecting critical generation stations.

There will be a cost associated with cyber security events, and failure to adopt cyber security measures might lead to the network relying on traditional asset-based redundancy instead. Cyber security events could also be used to manipulate market information, driving up the cost for end consumers. New business models, which may be more reliant on network 'intelligence' e.g. for aggregation or control of a smart city, are likely to be particularly at risk of cyber security incidents. Automated demand and decentralised generation may also be more reliant on comms and control infrastructure, so accommodation of low carbon generation and demand could be compromised by cyber security threats.

4.8 Provide capabilities for use in emergencies

G1 Plan for the timely restoration of supplies following a pro-longed local failure (Cold Start).

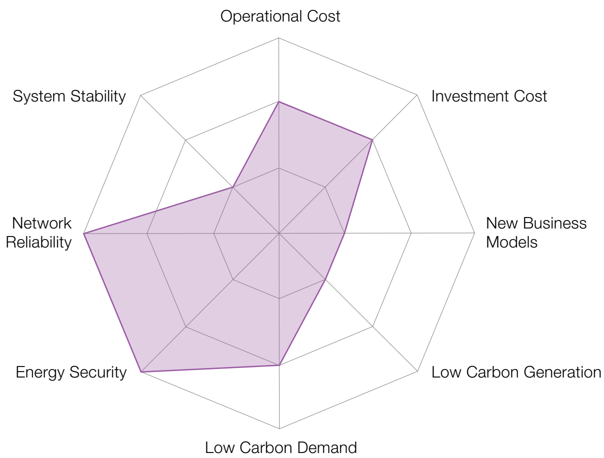


Implementation barriers

The ability of the system to accommodate low diversity demand for heat and transport is limited. Alternative solutions may exist, but these will be challenging technically and may need governance changes to support implementation.

For example, solutions may depend on the future DNO or DSO having the capability to directly or indirectly control demand (and possibly generation) following re-energisation. For example, micro-generation will have disconnected on loss of mains and hence any demand it was supplying (i.e. latent demand) will have to be picked up by the network on re-energisation. This would be technically challenging to implement and would depend on wider and more sophisticated monitoring and control infrastructure being in place. If this involved DSO control through smart meters, then this would have to be governed through the Smart Energy Code, and may require regulatory and legislative change to make this possible [34]. This also introduces a technical challenge, as the smart meter communications hub would either need to be 'cold-start secure' or DSOs would need to quickly operate a number of load switches following network re-energisation. Processes and requirements would have to be implemented through the existing code governance framework, which may not facilitate flexible/agile implementation [4].

New commercial and market arrangements may be needed in order to support new processes. Plans would have to consider the needs of customers, who may not be willing to accept a third party controlling their electrical demand (as has been the case in recent load-shedding incidents in Southern Australia [54]). New autonomous parties would add additional complexity to the cold-start process for example if the design of a smart city scheme prevents automated control of demand during re-energisation.

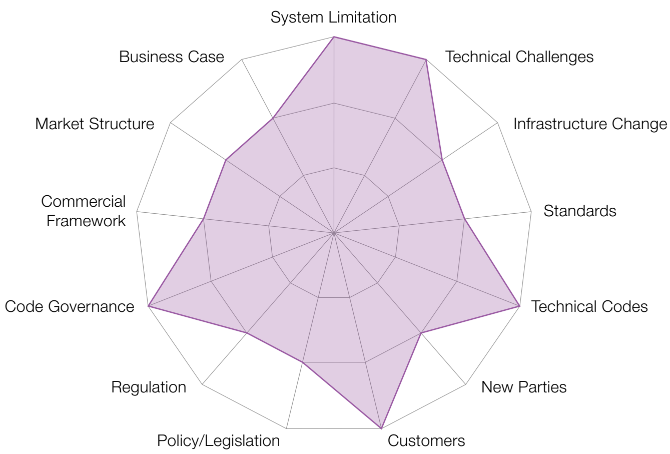


Consequences

Failure to implement this function would likely affect the ability of the system to manage cold-start re-energisation. This could compromise the security and reliability of users' access to the network e.g. if protection devices repeatedly trigger following the demand pick-up.

If this led to multiple prolonged interruptions, then this may lead to a significant operational cost for the system through the interruption incentives scheme (IIS). Ultimately, the DSO would perhaps seek to address this by conventionally reinforcing their network to accommodate the cold-start demand. Alternatively, this might fundamentally limit the ability of the system to accommodate heat pumps and other sources of demand which might exacerbate the issue.

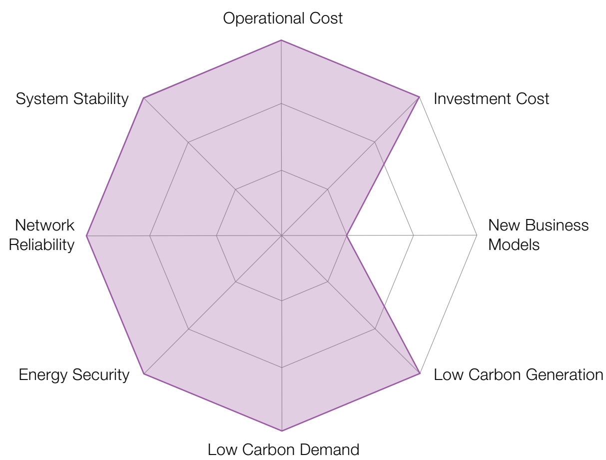
G2 Provide the ability to move between different modes of overall operation in the event or threat of a system emergency.



Implementation barriers
In the threat or event of an emergency, the ability of the system to co-ordinate a decentralised response will be limited e.g. the system operator may not have good visibility of distributed generation during many periods of the year [1]. Managing this will be technically challenging, and could require new communications and control infrastructure, with increased standardisation between devices [34], and changes to existing technical codes such as the emergency provisions within OC6 of the Grid Code [1].

Direct impacts on customers may be politically controversial [54] and could therefore be subject to strict policy requirements. If implementation required greater centralised control of decentralised assets during emergencies, then this might require changes in licensing and regulation. Any new emergency procedures would have to be implemented through the existing code governance framework, which may not facilitate flexible/agile implementation [4].

Emergency procedures would have to fit with existing commercial arrangements, particularly if they depended on a decentralised or aggregated response, and processes for suspending markets would need to be defined. Plans would have to consider the needs of customers, who may not be willing to accept a third party controlling their electrical demand (as has been the case in recent load-shedding incidents in Southern Australia [54]). There is a risk that new autonomous parties may add additional complexity to the cold-start process if their behaviour is not understood, for example they may prefer to island themselves during emergencies, potentially denying the system of valuable sources of generation capacity – and possibly inertia and stability.

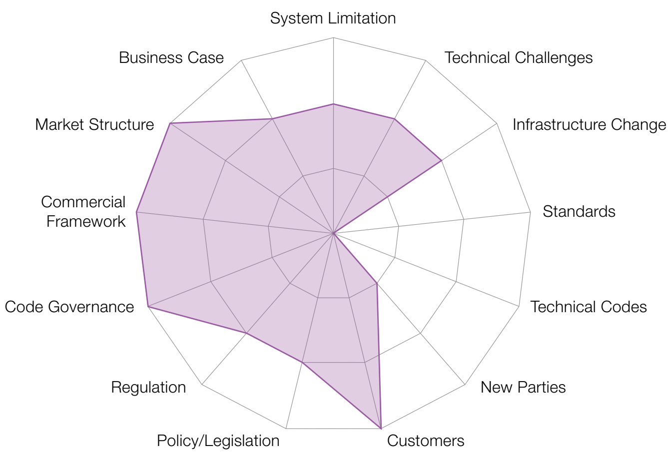


Consequences
This function could have serious implications for the overall security, reliability and stability of the electrical network. For example, if the system is unable to respond to frequency cascades, this could result in frequent outages.

Ultimately, this may place an overall constraint on how much intermittent and non-synchronous generation or autonomous/price-responsive demand can be connected at any time. For example, if in the future there aren't appropriate measures in place to respond to high RoCoF events, then the system may have to constrain renewables. This may in turn lead to inefficient investment in new assets to address emergency situations, or expensive constraints.

4.9 Market developments

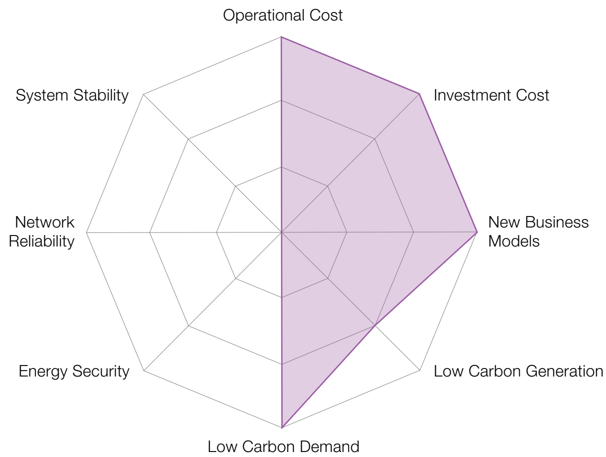
H1 Provide aligned financial incentives across the power sector (e.g. innovative or flexible tariffs) encompassing power, energy and ancillary services which provide appropriate signals to users and do not distort competition while giving consideration to their impact on customers.



Implementation barriers

The barriers to implementing this function cover all four barrier categories: technical, governance, commercial, and societal. In the short-term the obvious technical barrier is absence of granular (e.g. half-hourly) metering to support more innovative tariffs. Even once this functionality is in place (through the smart meter roll out) technical IT challenges will remain as some suppliers may need to make significant changes to their customer settlement systems to be able to accommodate new tariff structures [33]. Similar challenges may apply to DNOs should future DUoS charging leverage the more granular data provided by smart meters. The materiality of this barrier may vary significantly between different suppliers.

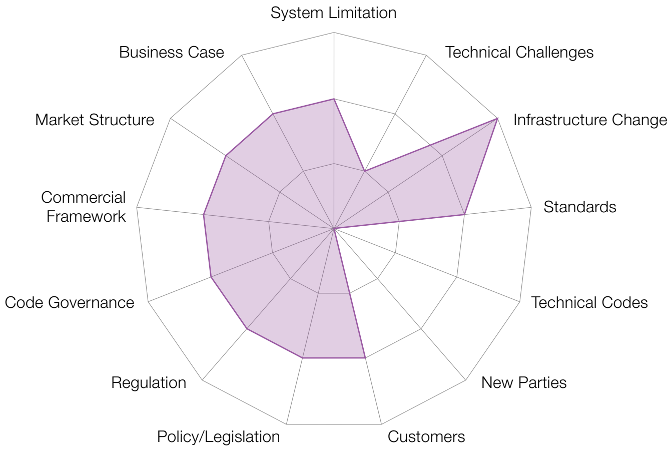
The current market structure, and specifically the absence of mandatory half-hourly settlement, is a significant barrier to the design and implementation of tariff structures that align financial incentives across the power sector [28]. Code changes will be required to introduce half-hourly settlement [33]. Ofgem has recently completed a consultation that may lead to half-hourly settlement becoming mandatory [29]. Even if such a decision is made, significant code changes can take a long time to design, consult on, and implement, as demonstrated by, for example, Project TransmiT, and the EDCM and CDCM projects. Currently industry governance could therefore act as a barrier to the introduction of new tariff structures. Further, overarching policy objectives, such as a desire for simple tariffs [55], could act as a barrier to tariffs that provide aligned financial incentives, although it is noted that since the 2010-2013 Retail Market Review Ofgem has implemented the CMA's recommendations to allow suppliers to offer a wide range of tariffs. Finally, the primary societal barrier is the lack of consumer engagement – it is unlikely that many customers would subscribe to tariffs that fully pass through half-hourly price signals. Tariffs that truly pass through incentives from the wholesale market are likely to face resistance [56].



Consequences

The most significant consequences of not having this function in place relate to the affordability of the power system, there are also consequences for decarbonisation. Without end-consumers being able to take advantage of aligned incentives the benefits of load-shifting will be limited, potentially leading to more investment in infrastructure (generation, networks) being required, and in high operating costs (e.g. cost of generation). Further, without code changes it could be impossible and/or prohibitively expensive to implement new business models [57]. On decarbonisation, demand lacks the incentives to shift from higher short run marginal cost, and higher carbon forms of generation, towards lower SRMC, and lower carbon forms of generation. In the absence of aligned incentives, it will be difficult and/or very expensive to accommodate new demand [31].

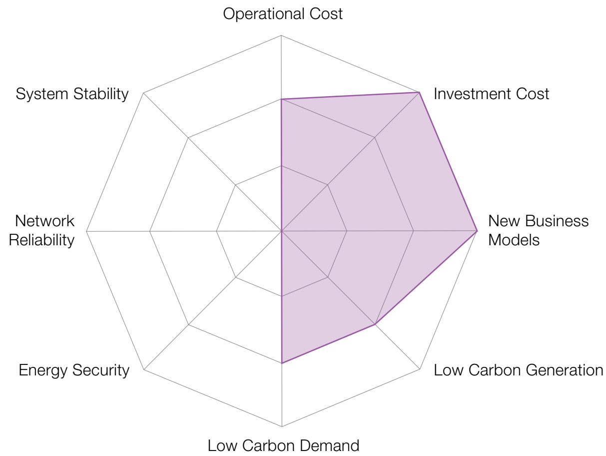
H2 Enable settlement for all existing customer profile classes to support flexible tariffs, e.g. half-hourly using smart or advanced meters.



Implementation barriers

The most significant barriers for this function are governance and commercial barriers. For example, the existing retail regulatory policy requires enhancements for customer half-hourly settlement [29] e.g. there are outstanding data protection and consumer safeguard issues. Also, the process for changing customer measurement class is complex although this may ultimately be mandatory for all customer classes [33]. Ofgem has initiated a process that could lead to half-hourly settlement (subject to more detailed consultation) [29]. Many consumers are unlikely to subscribe to tariffs that fully pass through price signals from half-hourly settlement. Long-term network charging arrangements for customers are still to be considered [29].

Any further delay in smart meter roll out will impact implementation of this function as will the need for integration of half-hourly settlement with existing systems including communications/IT for billing and switching. There have been issues with lack of compliance of smart metering with specifications SMETS to date [32] although these do not count towards smart meter roll out targets.

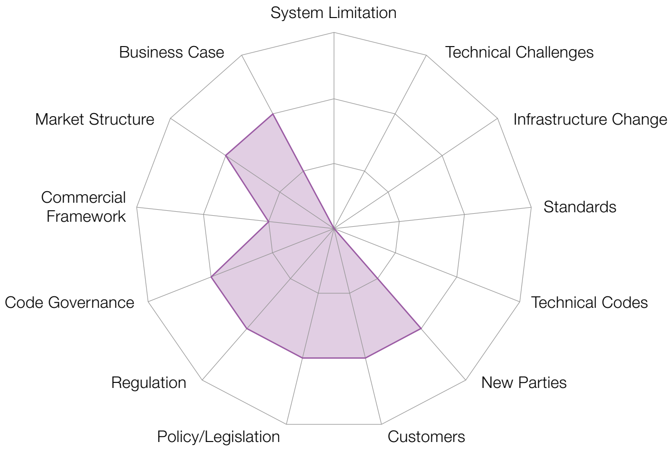


Consequences

Consequences for non-delivery include inefficient investment due to failure to capture full benefit of flexibility such as demand side response for example. This could result in investment in significant additional network capacity to address load peaks during times of high demand.

Inability to capture the full value of flexibility services to network capacity through HHS may result in lack of feasibility of new business models such as aggregated demand side response and management. Customers will be unable to access cost efficiencies through management of their own demand (and generation) patterns e.g. EVs, PV, heat pumps. This could reduce the appetite for small scale, low carbon generation and demand.

H3 Implement and co-ordinate a framework where the roles and value propositions of all significant stakeholders across the power sector can be managed.



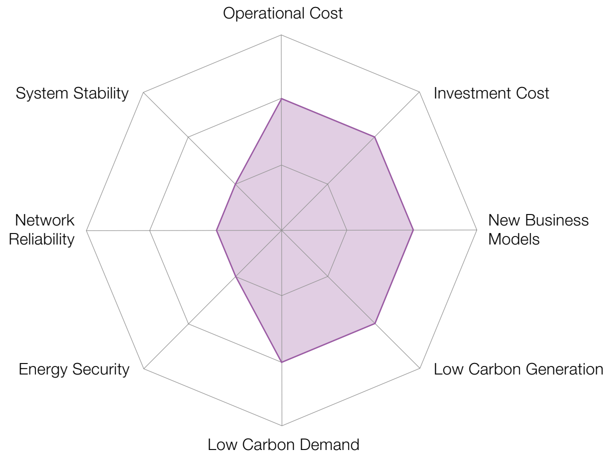
Implementation barriers

Insufficient consideration and co-ordination of affordability and decarbonisation objectives and policy e.g. through assessing value of decentralisation of energy in community energy schemes, smart cities etc. makes design and implementation of a framework that manages value propositions efficiently very challenging.

Existing regulatory framework is also a barrier to this. Regulation that is more flexible and agile to accommodate, respond to and enable an energy system where innovation is standard is essential for non-traditional business models to realise their value propositions [8].

Industry code plays a key role in value propositions. Independent aggregators (who are currently unlicensed) do not have a defined role within the Balancing and Settlement Code (BSC) that would allow them direct access to the balancing mechanism [28]. This means that they are unable to fully participate at local level although they can provide reserve and ancillary services. Commercial frameworks and the market structure also limit the participation and co-ordination of new parties e.g. longer term contracts will help create a more 'level playing field' for new technologies and incentivise investment. Also, a flexibility market will encourage the increased value propositions from a range of new suppliers and aggregators [58].

Limited participation and co-ordination of third parties reduces value for customers e.g. if DSR causes more complexity in the energy market, this could have a particularly negative impact on vulnerable consumers [3].

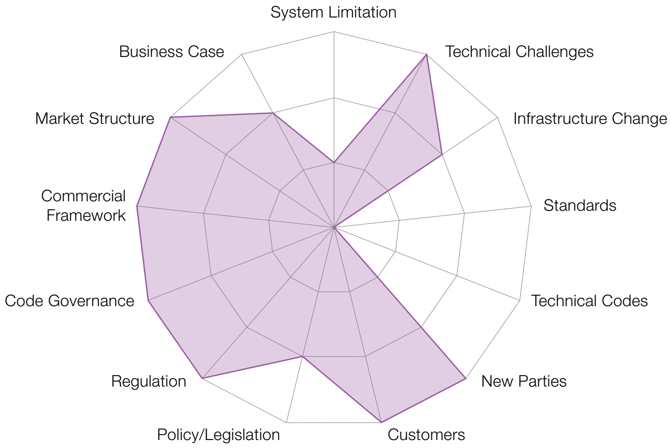


Consequences

Failure to create a market that enables e.g. flexibility services to be properly valued and accessed, could lead to inefficiencies in procurement of system services for example and greater balancing conflicts between SOs. This could lead to higher operational costs. Network investment could also be higher if there are less flexibility services and thus, constraint management services are more limited.

Lack of co-ordination of roles and value propositions will certainly be an impediment to new business models and could affect the growth of low carbon generation and demand, which could offer flexibility services as part of their business models.

H4 Provide market mechanisms e.g. peer-to-peer trading, to allow all customers to access the value realised by their actions.

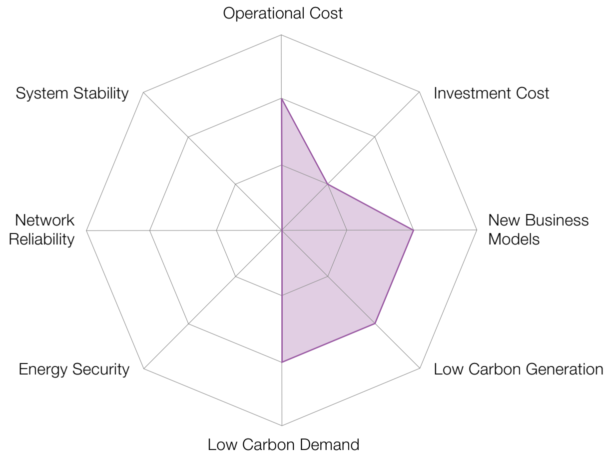


Implementation barriers
Technical barriers relate predominantly to IT infrastructure. Significant changes to existing functionality and the addition of new functionality may be a barrier to implementing peer-to-peer (P2P) trading. This is likely to be a greater challenge for incumbents with legacy IT infrastructure, which might reduce the availability of more innovative commercial propositions to 'sticky' customers. However, it is acknowledged that there is high uncertainty over this barrier score as there is little reliable evidence available in the public domain and the costs are likely to vary significantly by solution design, and by the state of an incumbent's existing IT infrastructure.

It is likely that changes to existing licences and to the regulatory framework will be needed e.g. common data protocols could be mandated, or the relationship between P2P trading platforms and suppliers might need to be prescribed. A further regulatory barrier is network charging. The argument that current charges do not truly reflect the benefits of local P2P trading – is currently an obstacle to P2P trading customer propositions being commercially attractive [8], [59].

Depending on the extent to which changes are made to the market structure, there may be a need for new licence types/requirements to implement some P2P trading propositions. The extent to which P2P trading is regulated and licensed is likely to impact the extent to which new parties engage in associated business opportunities. For example, if suppliers (of any type) are out of the loop that may impact the Balancing and Settlement code. Also, the incorporation of network charges (these are currently embedded in suppliers' energy bills) and how far up network charges should be applied (the distribution voltage hierarchy and beyond) will need to be resolved.

It is questionable how many customers will really be engaged in propositions involving P2P trading, which might also be a barrier to the development of P2P propositions. If engagement is low that could undermine commercial viability. There is limited evidence over engagement with P2P trading to date, but it is generally accepted that engagement in the energy market overall is low.



Consequences
There are some consequences to both affordability and decarbonisation of this function not being in place, but these consequences have not been rated as being of 'high' materiality in our analysis.

With the right price signals, P2P trading could help consumers to find opportunities to improve system efficiency.

On decarbonisation, local P2P trading with appropriate changes to network charging could make embedded renewables and flexible demand viable in locations where they were not previously viable.

5. Test Cases

Function barriers and consequences are presented below in detail for three functions. These three functions have been explored in detail by WP2, WP3 and WP4. Function needs are summarised from WP2.

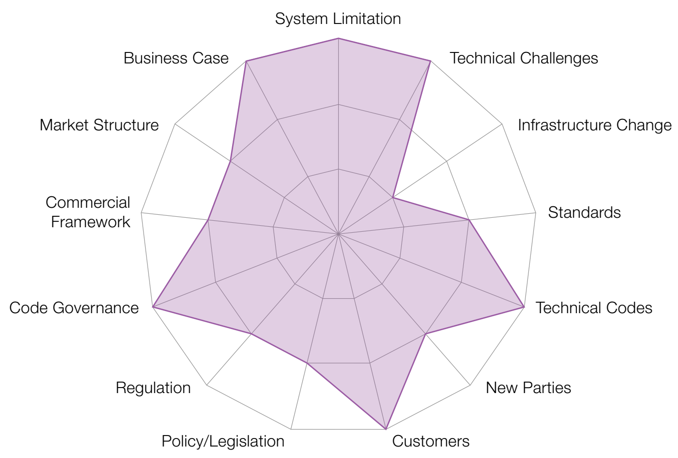
5.1 Function G3

No.	**G3**	**Function Description**	Plan for the timely restoration of supplies following a total or partial shutdown (Black Start).	
		Function Needs (WP2)	**Process:** Planning a Black Start. **Process:** Engaging with Black Start service providers. **Process:** Developing technical criteria for Black Start service providers. **Modelling:** Black Start scenarios. **Infrastructure:** Secure communications, control, and IT infrastructure for controllable energy resources. **Interaction: A1, B2, C1, C6, E2, F2, F3, F4, H1, H3, H5.**	
Implementation Barriers				
Technical				
System functional limitations			**H**	Black Start capabilities are currently sourced from a small pool of large thermal generation. There is uncertainty on how future Black Start capabilities will be procured with increasing and intermittent non-synchronous generation on the system [1] with different performance characteristics. Under future scenarios with less large thermal generation, more distributed and weather dependent generation and low carbon demand, alternative sources of Black Start will be required [1].

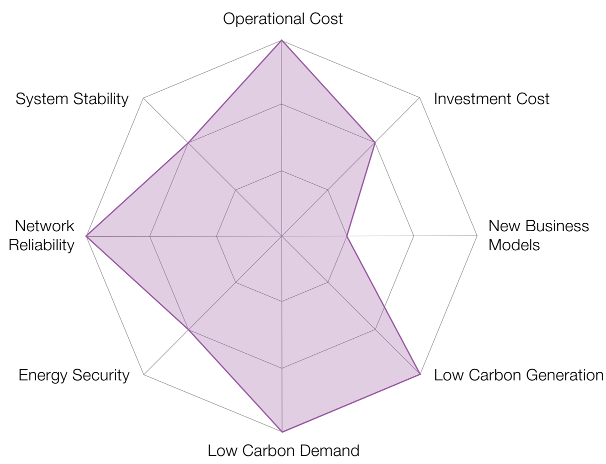
Technical challenges to implementation	**H**	Black Start is dependent on having sufficient resources to create stable power islands with control of voltage and frequency, protection capability, and an ability to limit demand to available generation [60]. Black Start capability requires resilient and secure communications infrastructure and functionality whether centralised or decentralised. Communications and control systems sophistication and resilience is not at a sufficient level specifically for (aggregated) low carbon generation and demand [60]. Existing modelling and forecasting capability and skills are not at the level of sophistication required to incorporate a wide range of risk and recovery scenarios incorporating intermittent generation and operate in real-time [62]. There are also significant data processing and interfacing implications to enable monitoring of an increased volume of Black Start capability sources. The resilience of intermittent generation such as wind turbines, and their protection systems to accommodate repeated faults and voltage dips might be a limitation (as per South Australia experience) [30].
Changes to infrastructure	**L**	Extent of communications and control systems infrastructure is currently insufficient to incorporate large-scale contribution of (aggregated) DER and remain resilient to prolonged power outages.
Industry standards	**M**	There is no existing standard for Black Start capability of a system operator [61]. Such a standard could help ensure the right balance of Black Start services versus cost of providing the service. Lack of co-ordination of industry standards between network operators [61] e.g. capability of Grid and Primary substations for providing SCADA control and tripping functionality following a Black Start event. Communication, control, monitoring and protection standards will also need to be enhanced for granularity, specificity, latency and resilience to prolonged power outages and to ensure they are appropriate for restoration methodology [60], [61], [14]. There is likely to be significantly less load diversity with increased low carbon demand i.e. EVs, HPs, direct heating etc. Existing standards do not enable customer demand to be managed to counteract loss of diversity. There are significant training and testing requirements for provision of Black Start capability [61] with implications for smaller providers e.g. aggregator business models.
Technical codes	**H**	The Grid Code stipulates that the system operator should procure Black Start capability although it does not specify what this capability should be [9]. Technical performance requirements for black start in the Grid Code may be a barrier to some new service providers e.g. start-up capability of a black start provider (required to energise part of the transmission or distribution system within two hours of instruction from NGET), and the block loading threshold of 35 MW which may restrict Black Start services providers to plant of 100MW+ however this can be aggregated [9]. Embedded small generating plant is not currently required to meet the performance requirements of the Grid Code [18]. This would need to be reviewed if these plants were to contribute to Black Start.
Governance		
Policy and legislation	**M**	Lack of policy certainty for national plant portfolio could be a barrier to developing the appropriate restoration strategy and Black Start capabilities.
Regulatory framework	**H**	Lack of co-ordination with other energy sectors in the existing regulatory framework. Also, interconnectors are not being contracted for Black Start services although the technology used for interconnectors is proved capable of being able to provide Black Start services [61]. Lack of a Black Start performance standard i.e. detailed technical requirements, in the regulatory framework [61] which could result in uncertainty for development of the appropriate restoration strategy and Black Start capabilities. Current BSIS incentives are short-term (the incentive scheme covers two-year periods at a time) [61] and not set by reference to a defined service level.
Industry code governance	**H**	The existing Grid Code and Distribution Code may require substantial amendments to better reflect the contribution of alternative sources of Black Start in future. This is likely to involve multiple stakeholders and could be a lengthy process to ensure that technical, commercial and regulatory factors are considered. The existing process may not support a system wide perspective [4].

Commercial		
Commercial framework	M	Existing services contracted from large thermal generators with contracts based on short-term incentives is a limitation [61]. There is no incentive to contract Black Start services longer-term which reduces certainty for potential new providers/power plants to design in Black Start capability at higher capital cost.
Market structure	M	The absence of a well-defined Black Start performance standard negatively affects NGET's ability to deliver these services efficiently [61]. It is challenging to justify procurement strategy and associated costs to manage risks of system shutdown and potential changes in strategy and costs due to increasing level of non-synchronous generation for example.
Strength of business case	H	The Black Start procurement strategy needs to be economic and efficient for consumers. There is uncertainty on how this will develop with increasing non-synchronous generation and less thermal generation on the system [1]. There is also uncertainty around the most optimal re-energisation strategy depending on the changing generation mix (which may vary day-on-day or even hour-on-hour), and so provision of multiple Black Start approaches may lead to increased network capital cost and reduced reliability due to complexity [61].
Societal		
Accommodation of new parties	M	Based on existing Black Start requirements, service providers are currently generally limited to large power stations. Requirements are not currently suitable for intermittent renewable generation. The co-ordination framework does not reflect a greater number of stakeholders and the changing roles in future e.g. DSO, smart cities, mini-grids that might run islanded during Black Start events subject to sufficient voltage and frequency control capability, and resynchronisation capability [9].
Accommodation of customers	H	There is limited public understanding of Black Start and restoration strategies. This could result in conflicts where community energy group generation schemes provide Black Start services, but during restoration, the community does not immediately have electricity restored. Also, requirements for demand side management during restoration are not defined and this could become an issue with an increase in less diverse low carbon demand.
Consequences		
Inefficient operational costs	H	Lack of long-term incentives could reduce investment in Black Start capability, potentially resulting in a smaller market of providers and thus higher cost black start services.
Inefficient investment	M	Lack of planning for an appropriate Black Start approach with increasing non-synchronous and intermittent generation could lead to inefficient investment. Adoption of a sub-optimal restoration strategy and then a need to modify it significantly could result in stranded investment. Lack of long-term certainty for potential investors in provision of Black Start capability could result in limited or inappropriate capabilities being available, thus leading to increased capital costs to meet requirements.
Impediments to new business models	L	There are unlikely to be significant impediments to new business models.
Decarbonisation		
Accommodation of low carbon generation	H	There is likely to be some impact on low carbon generation if it is not able to contribute significantly to Black Start capabilities. This may affect the appetite for increasing intermittent non-synchronous generation on the system if system restoration may be compromised.
Accommodation of low carbon demand	H	There may also be an impact on accommodation of low carbon demand which is likely to have much less natural diversity compared to existing load. This may affect the appetite for increasing low carbon demand on the system if network restoration may be compromised.
Security		
Security of energy supply	M	Lack of contribution of non-synchronous generation to Black Start capability may make recovery more difficult especially as nuclear generation – which in summer periods might be the main source of system inertia – will be offline during the first day(s) of system recovery.
Reliability of networks	H	The most significant consequence for non-implementation of this function is lack of reliability of the system in the event of a blackout, notwithstanding the major consequences that this could also have on societal stability.
Maintaining system stability	M	Non-synchronous generation can be considered to weaken the stability of the network as there is less synchronous inertia in the system as a result. The likely effect for the system is that it will be more prone to instabilities including frequency deviations (RoCoF) and voltage variability if no effective counter measures are introduced [60]. This may increase the likelihood of a total or partial system shutdown and is a key consideration for Black Start planning.

Implementation Barriers



Consequences

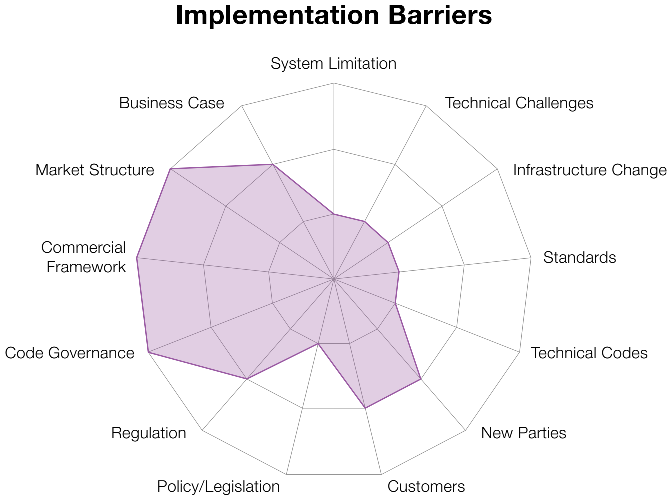


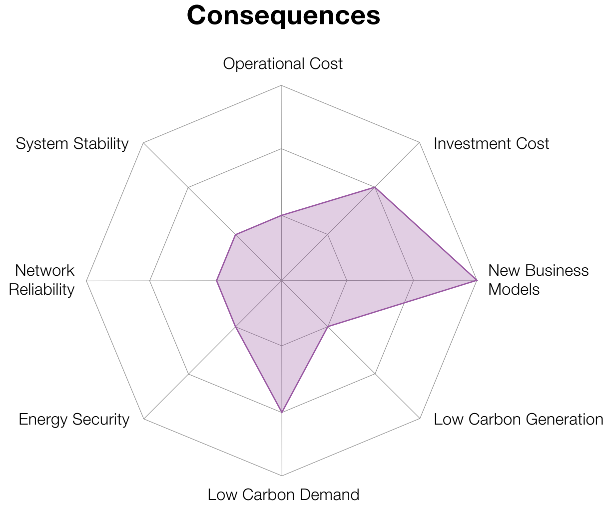
5.2 Function H5

No.	**H5**	**Function Description**	Provide a market structure that enables customers to have choices within the power system.
		Function Needs (WP2)	**Process:** Processes that allow development and evaluation of market design options. **Process:** Mechanisms for implementation of new market structures. **Process:** Mechanisms which allow users and service providers to interface with the market. **Modelling:** Capability to evaluate proposed market changes. **Infrastructure:** Monitoring required as a prerequisite to determining what market structure is appropriate. **Interaction: H1, H3, C6, H2, H5 and H6.**

Implementation Barriers		
Technical		
System functional limitations	**L**	Limitations in system monitoring, modelling and forecasting could constrain the scope for fully exploiting new service offerings and hence the development of appropriate markets.
Technical challenges to implementation	**L**	Implications for data exchange and management to fully exploit capabilities of new highly disaggregated DERs to support new markets could be a limitation [25]. However, newly installed smart grid technologies could simplify the new market process by enabling much finer granularity [25].
Changes to infrastructure	**L**	There is limited data and communications infrastructure to support the functioning of markets with DER [8].
Industry standards	**L**	Lack of appropriate industry standards on data and cyber security for monitoring and data management systems [49]. There is potential for cyber attacks (hacking) to send pricing signals that destabilise the grid. ENA and ENA members are working with government and other key stakeholders to ensure risk-based scalable approaches to cyber security (e.g. through government liaison and ENA Cyber Security Forum) continue to develop [11].
Technical codes	**L**	There is insufficient consideration of technical requirements and benefits of flexibility services in grid codes e.g. different levels of security of supply cannot be personalised depending on levels of customer load automation [6].
Governance		
Policy and legislation	**L**	Changes to policy are not a significant barrier to implementation of this function. The Government is actively engaged in implementing this function and has already put licence conditions in place that requires suppliers to set up and fund the Central Delivery Body in order to deliver a national smart meter awareness campaign and effective consumer engagement [31].

Regulatory framework	**M**	Some existing regulation acts as an obstacle to consumer-led propositions and a broad range of business models/services – such as licensing arrangements and the high upfront risks and costs to new suppliers. Regulatory changes should be made where these are in the interests of the system as a whole [63]. Roles and responsibilities of parties in using and providing flexibility must be properly defined [57]. This relates to the process function needs. There are currently limited regulatory tools to protect consumers who contract with independent aggregators. Consumers might therefore be at risk from behaviours or offers that are unfair, misleading, or unclear [28].
Industry code governance	**H**	The evolving market structure and accommodation of new parties may require significant updates or changes to existing industry codes involving a wide range of stakeholders. Specifically, this will also require the involvement of new parties in the relevant governance processes [8], [3], [63]. Code governance processes can be fragmented and generally do not take a whole system view [4]. Also at the time they were constituted there was not the technical interaction between homes and networks that is now emerging
Commercial		
Commercial framework	**H**	Commercial models to accommodate consumer-led and/or community energy propositions are still at an early stage of development. Access to data will be a significant barrier to new parties to identify and develop new business models [25], [28], [63], [11].
Market structure	**H**	Market structure is not currently in place to support innovative new products that participants may want to offer to consumers [11]. It should ensure everyone benefits from these products and in order to do so it must still be better understood how to balance benefits amongst customers, through e.g. direct rewards or cost-reflective tariffs [25]. Furthermore, the market should enable aggregation of DSR as this could increase benefits and reduce risks for customers [58], [28], [63].
Strength of business case	**M**	If implementation of new market processes requires changes to existing systems, e.g. for trading, billing, settlement etc., then the implementation costs could be substantial.
Societal		
Accommodation of new parties	**M**	Multiple new parties may need to be involved in future market processes and this will require engagement and co-ordination across the sector e.g. current approaches of grid constraint management can prevent community energy generation schemes from going ahead [8]. For providers and users of flexibility, there are technical, market and commercial barriers as described above that prevent them from realising the full benefits of flexibility [57].
Accommodation of customers	**M**	Diverse customer needs and potential difficulty in engaging with certain segments is a barrier to design of an engaged market process, as is lack of technical knowledge [25], [58], [3]. Customer engagement can often drive technology deployment [3]. However, there are positive signs that consumers will engage fully with smart meters. In a recent survey carried out by Populus on behalf of Smart Energy GB [40], 84% of people with a smart meter said they were likely to recommend one to others [58].
Consequences		
Inefficient operational costs	**L**	Failing to create a market with a wide range of flexibility services may result in less balancing services so the cost of constraint management and balancing actions increases.
Inefficient investment	**M**	Market arrangements that are overly complex might reduce investments in flexibility [57] at local level and thus lead to inefficient investment to provide network capacity [11].
Impediments to new business models	**H**	A market structure that is not engaged might expose customers to more risk and reduce their appetite for new business models [58].
Decarbonisation		
Accommodation of low carbon generation	**L**	A market structure with lack of appropriate decarbonisation incentives can reduce uptake of low carbon generation [58].
Accommodation of low carbon demand	**M**	Low carbon demand is still likely to connect; however there may be reduced value to customers in an unengaged market so uptake could slow.
Security		
Security of energy supply	**L**	Non-implementation of this market based function is not likely to affect security of supply significantly.
Reliability of networks	**L**	Similar to above.
Maintaining system stability	**L**	Similar to above.





5.3 Function H6

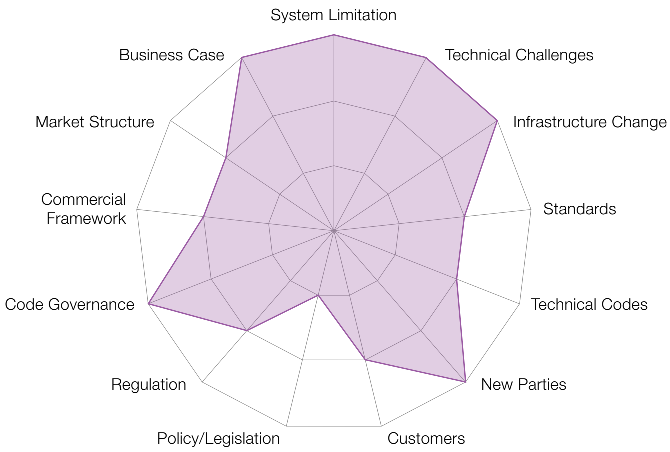
No.	**H6**	**Function Description**	Enable customers to choose from a full range of market options which determine how they interact within the power system including individual, community and smart city services.
		Function Needs	**Process:** Processes for developing new market options. **Process:** Mechanisms for engaging with customers. **Infrastructure:** Network assets to enable market options. **Modelling:** Capability to determine the viability of new business models. **Modelling:** Capability to understand impact of customer behaviour on the system, given new propositions. **Interaction: H1, H3, C6, H2, H5 and H6.**

Implementation Barriers		
Technical		
System functional limitations	**H**	Taken in a broad sense, system functional limits could be a significant barrier. For example, the functionality is not yet in place to offer many smart city services (and certainly not on a widespread basis). RD&D and Innovation is being carried out to better understand smart city schemes [64]. Another example of a system limitation is network capacity where it is not always technically possible to provide the full range of market options to customers. For example, it may not be possible to provide a frequency response service in an area of the network that is already close to export capacity (at least not without network reinforcement). This links to the function need of modelling.
Technical challenges to implementation	**H**	As above, if taken broadly, the technical challenges are those of integrating independently managed market options such as smart city and community energy schemes into the wider system whilst ensuring whole system optimisation are significant. There will be a number of barriers relating to modelling, monitoring and control for the specific market option as well as for integration with the wider system.
Changes to infrastructure	**H**	Existing infrastructure such as monitoring, communications and control to accommodate community energy projects and smart city services for example is not adequate. This will require significant investment and innovation to overcome this barrier and integrate with existing assets [28], [3]. From an individual customer perspective, the smart meter roll out is slower than planned [31], [32], limiting customer choices. There have also been issues with HEMS interoperability where devices from two different vendors may not be able to communicate with one another [23].
Industry standards	**M**	Limited industry standards e.g. lack of consumer data protection and cyber security standards for ‘beyond the meter’ automation and DER [24].

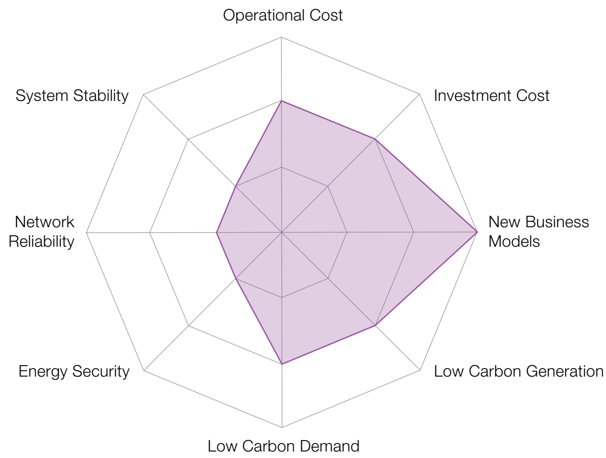
Technical codes	**M**	Insufficient consideration of technical requirements and benefits in grid codes e.g. different levels of security of supply cannot be personalised depending on customer load automation. Also, existing grid codes do not reflect the greatly increased requirements for co-ordination of multiple new parties and constraint or balancing actions that are not in conflict. The distribution code only includes operational planning for embedded generation and demand control is only in case of emergency [9], [18].
Governance		
Policy and legislation	**L**	New social and legal constructs are required to engage consumers, especially to enable social interaction opportunities at community level [26].
Regulatory framework	**M**	Existing license obligations may not be appropriate [13] e.g. with new business models built on third party services, what are the roles of suppliers and consideration of which activities should be licensed? This barrier links to the processes function need.
Industry code governance	**H**	The evolving market structure and accommodation of new parties may require significant updates to the existing industry codes. Specifically, this will also require the involvement of new parties in the relevant governance processes. Roles and responsibilities of new and existing sector parties should aim to maximise synergies and avoid conflicts and delays; clarity over accountabilities for aspects of system management will be critical [8].
Commercial		
Commercial framework	**M**	Existing commercial frameworks limit contribution of diverse flexibility services e.g. energy storage [8] and are not yet suitable to accommodate large number of new actors – community energy, smart city service providers etc. that could potentially be involved to provide a full range of customer options. Commercial models to accommodate consumer-led and/or community energy propositions are still at an early stage of development. There are also issues around access to data and how it can be used. There may be opportunities available as a result of an open data convention [3], [10] but there may be significant commercial sensitivities.
Market structure	**M**	The existing market structure does not support innovative new products that participants may want to offer to consumers [63], [58], [10].
Strength of business case	**H**	This may require investment in new substation infrastructure e.g. smart cities rely on large numbers of sensors, actuators, communications, data platforms etc. The business case may be challenging without greater certainty on market opportunities and risks. There are also issues of scale and availability of start-up funding [3], [8]. This links to the function need for modelling and processes.
Societal		
Accommodation of new parties	**H**	Many new parties will be potentially involved in offering a full range of market options such as smart city operators, aggregators, community energy companies. Organisations outside the traditional energy industry could also offer services based on data available from smart city schemes. There is a great challenge in co-ordinating and integrating all these actors, ensuring appropriate codes and standards are in place to govern/regulate their activities, ensure stability and security of system operation etc.
Accommodation of customers	**M**	Customers have diverse needs and there may be difficulty in engaging with certain segments. A lack of technical knowledge could also be a barrier to customers trying to exercise choices. A number of customers are already excluded from a full range of customer choices, e.g. pre-payment meter customers, so delivery solutions need to avoid 'lock-in' [58]. Vulnerable customers and smaller businesses may not be able to access full value from smart appliances, HEMS, BEMS, and may miss out in terms of accessing value from more personalised or flexible tariffs [24].
Consequences		
Inefficient operational costs	**M**	An inability for customers to access a range of market options including flexibility services could lead to inefficient operation of the system and higher balancing costs for example [11], [8].
Inefficient investment	**M**	Inefficient investment may occur due to a lack of customer options that enable contribution to management of existing grid capacity.
Impediments to new business models	**H**	The lack of market options for consumers may deter new, innovative propositions that would otherwise have come forward from being developed [67], [11], [8].

Decarbonisation		
Accommodation of low carbon generation	**M**	Customer market options such as community energy schemes which support greater accommodation of low carbon generation may be limited.
Accommodation of low carbon demand	**M**	Customer market options such as vehicle-to-grid services (or other EV-related services such as frequency response) which support greater accommodation of low carbon demand may be limited.
Security		
Security of energy supply	**L**	Security of supply should be maintained through appropriate network investment and by exploiting network support services such as DSR.
Reliability of networks	**L**	Network reliability will not be affected by non-implementation of the function so long as appropriate (albeit potentially more expensive) network investment takes place.
Maintaining system stability	**L**	System stability should not be materially impacted provided sufficient alternative (albeit potentially more expensive) sources of conventional or synthetic inertia are secured.

Implementation Barriers



Consequences



6. Barriers

Through our impact analysis, we have identified that the highest existing barriers to function implementation are:

- Industry Code Governance.
- Technical challenges to implementation.
- Regulatory framework.
- Commercial framework.

In assessing function implementation barriers, we have also considered the market barriers identified through the stakeholder engagement carried out by WP1A and the delivery options and RD&D and Innovation developed by WP2.

6.1 Industry Code Governance

Whilst acknowledging Ofgem's review of code governance following the CMA's recommendations, existing sector code governance arrangements have been identified as a significant and prevalent barrier for function implementation across the impact analysis. This is explored below.

Existing process of industry code governance is not agile or flexible enough to respond to the degree and pace of future change required

Implementation of functions will require significant interaction with technical and market codes and potentially complex and rapid changes. For example, the transition to half-hourly settlement may require changes to streamline the Change of Measurement Class process, and to tackle unintended consequences such as temporarily higher T-charges in the year when CoMC takes place [33]. Another example is that Black Start stations as defined in the Grid Code are based on large thermal power plants (thermal, hydro). Black Start station requirements are not suitable for intermittent generation although these may need to contribute to Black Start capability in the future. Greater co-ordination of black start actions from a range of system operators (transmission/distribution etc.) should also be reflected in the Grid Code. There is no balancing code at distribution level; this could inhibit a transition to a distribution system operator model and wider procurement of flexibility services. Alternatively, the DSO may have a balancing support role (i.e. not 'balancing' per se but managing net power flows within certain limits – for example under each GSP).

Greater co-ordination of investment and operational planning both intra and inter-system is likely to require a change in defined roles and responsibilities of all key stakeholders i.e. system operators, generation and demand, smart cities, community energy schemes. This should be reflected in the grid code and the grid code change process to maximise synergies and avoid conflicts. For example, clarity over accountabilities for system operation [10] particularly under emergency conditions and Black Start will be critical.

Industry experience suggests that code changes can take a long time to design, consult on, and implement. For example, changes to network charging and connection arrangements made through Project TransmiT, EDCM, and CDCM all took several years. Timescales of this magnitude may result in substantial delay to the implementation of functions and thus the realisation of consequences. Changes to industry code in future are likely to involve a greater number of stakeholders, including those that operate ‘beyond the meter’, and consideration of wider factors.

The existing process may not support a system wide perspective [4]. With the power sector undergoing rapid change, this risks stranding of effort to modify code incrementally which then needs to be further adapted. Fundamental code reviews should however be given sufficient time for consideration and consultation.

6.2 Technical challenges to implementation

There is a range of significant technical implementation barriers for FPSA functionality identified through the impact analysis. These are outlined in detail below.

Modelling and forecasting capability need enhancement

From investment planning timescales through to real-time, a number of industry studies have identified that existing modelling and forecasting capability is a barrier to capturing the full value of DER and future flexibility services, whilst ensuring security of supply and least cost optimisation.

Future networks will be associated with increasing complexity, stakeholders and interaction with other vectors. However, there is currently a lack of a whole system modelling approach in sufficient granularity to support cost effective co-ordination of planning and operation [2]. For example, there is limited integration between power system modelling and dispatch/market modelling. Enhanced modelling capability is required to capture the key phenomena and interactions across different locations and energy infrastructure operation and design. For Black Start modelling, a wide range of risk and recovery scenarios incorporating Black Start capabilities of intermittent generation and other parties including other vectors may be required with simulation closer to real time [62]. Also, the existing network planning approach at distribution level is based on a deterministic approach; a more probabilistic approach would enable greater utilisation of assets [6].

There is limited existing real-time forecasting and modelling capability outside the TSO [10], [4]. Therefore, there is a capability gap for forecasting in other parties such as DNOs. Forecasting capabilities may be challenging for new parties with limited historic data. There are also significant new data processing and interfacing implications to enable forecasting and modelling for an increased volume of DER across the system [10] both for centralised and decentralised systems.

Limits of monitoring, control and communication in existing system

Existing monitoring, control and communications systems are not at the level of sophistication and resilience required for a number of functions. There is limited monitoring and control specifically at lower voltage levels of the distribution network. For example, smart metering deployment is delayed [31], [32] and there is a lack of interoperability of HEMS [23]. Also, apart from a relatively few more recent innovations such as phase-shifting transformers and soft open points, controllable network points are generally limited to circuit breakers, transformer voltage tap-changers and a limited number of power electronics based assets.

Existing control strategies particularly at distribution network level (or smart city) are not sufficiently robust for future complex power flows and flexibility/balancing actions [27], [10] and there is limited integration of controllable DER with network management software. In order for low carbon generation and demand to fully contribute to balancing actions and Black Start, more advanced control systems will be required to facilitate controllability and avoid unwanted feedback and instability. These may need to be "intelligent" i.e. automated, self-healing and incorporating machine learning capability, and communicate with a range of third parties. Lack of suitable control and protection infrastructure in network assets and DER e.g. widespread soft-start controllers, randomised start-up delays and frequency-sensing devices [12], [4], will inhibit this.

Existing communications hardware and software is not sophisticated or extensive enough to support real-time, identification, co-ordination and control of DER and operational restrictions [10]. For example, existing communications bandwidth is insufficient for "big data" and there are significant integration challenges [12].

Standards are not adequate for future functionality e.g. cyber security, data access, control interfaces and interoperability

Existing industry standards do not fully address the challenges and risks associated with the significant increase in communication links between a wide range of parties across critical power infrastructure. There are also significant implications for consumer data protection.

The move to half-hourly settlement and innovative supplier models that provide flexibility services for example, as well as greater transparency within the power sector, may conflict with existing consumer data protection standards. BEIS and Ofgem are seeking to identify design solutions which are compatible with relevant data protection regulations without imposing disproportionate costs or complexity on industry [29].

There is likely to be a significant increase in communication links and data sharing between the GB system operator, network operators, third parties and customers in future leading to concerns regarding cyber security.

There is currently an ongoing review of cyber security for Critical National Infrastructure (CNI), but it is not clear whether this will holistically consider the security requirements of, for example, IoT controlled devices connected to the public electricity network. Outside of CNI, cyber security regulations in the UK are focused on data protection rather than network security, with wider requirements addressed through guidance and best practice. This might not be sufficient to encourage or incentivise necessary actions to address threats beyond-the-meter [50], particularly as building a business case for cyber security investments can be challenging, as the business case generally relies on positive externalities [53] and this may be difficult to achieve within a competitive market.

There is an existing lack of standardisation of control, protection and automation solutions at network level [20], [22] and customer level [23] resulting in reduced interoperability, re-configurability and controllability. This also limits modular solutions as there is a tie in to specific technology. Elements of this are being explored in the SP Energy Networks' innovation project FITNESS [22] for example.

6.3 Regulatory framework

The regulatory framework has been identified as a significant and prevalent barrier for function implementation across the impact analysis. These barriers are closely related to barriers relating to governance, the commercial framework, and policy/legislation. The key 'themes' within this barrier are:

- Existing licensing and regulatory arrangements do not account for new parties and new business models.
- The whole system (including other energy vectors) is not considered holistically within regulation.
- The regulatory framework needs to balance flexibility and agility with long-term certainty.
- Lack of data access for new parties.

Existing licensing arrangements do not account for new parties and new business models

The existing framework for regulation in the GB electricity market has been designed and implemented iteratively since the early 1990s, and reflects the roles and responsibilities that have evolved over time. This includes some fundamental revisions to the regulatory approach (e.g. the adoption of the RIIO framework) and ongoing reforms such as the recent announcement from BEIS, Ofgem, and National Grid about the System Operator's role. However, further changes are likely to be required in order to achieve implementation of the enhanced functionality envisaged within FPSA. For example, the transition from DNO to DSO may require new roles and responsibilities to be defined within the distribution licence, as noted by Scottish Power in their DSO vision [10]. Existing regulatory arrangements are not well suited to the business models of local energy service providers (such as community energy schemes or smart cities) e.g. prospective suppliers are allowed to apply for a licence which is only applicable in certain geographic regions, but to secure this the supplier would need to argue the restriction on the basis of an over-riding public interest rationale. Simpler arrangements may be more likely to deliver the benefits customers can afford, such as improved choice [13].

BEIS and Ofgem are currently taking major steps to address this through their call for evidence on A Smart, Flexible Energy System, as well as through Ofgem's work on Non-Traditional Business Models and their establishment of a "Regulatory Sandbox" for trialling new business models. Some of these aspects are discussed below in the context of commercial barriers.

In general, new roles and responsibilities will be required for enabling the delivery of many of the functions identified within FPSA. For example, responsibilities for considering and mitigating new types of operability threat, such as cyber security, could be required for a range of parties in the sector, including parties that have historically not-been 'regulated' such as smart appliance providers. Additionally, there are many functions which require collaboration and co-ordination across the sector. In the current market, this could involve many parties and there would need to be a governance framework in place. This might, in general, require further obligations and incentives on licensed parties. For example, greater co-ordination of transmission planning has resulted in new requirements for the system such as the Network Options Appraisal process. WS6 of the Smart Grid Forum noted the general requirement for regulation which promotes visibility and co-ordination [3].

The whole system is not currently considered holistically within regulation

In order to promote a whole system approach within the power sector (and wider energy sector), holistic whole system thinking may need to be better reflected in regulatory approaches. There are already some clear differences in the regulatory treatment of the SO, the TOs, and the DNOs. For example, both the DNOs and TOs are regulated via eight year price controls, but these are staggered by two years (with RIIO-T1 running from 2013 – 2021 and RIIO-ED1 running from 2015-2023). The SO BSIS price control is only two years long. It is acknowledged that the ENA TSO-DSO project [68] is actively exploring mechanisms for co-ordinated transmission and distribution planning. Whilst misaligned transmission and distribution price control periods do not in themselves prevent investments delivering cross-boundary or whole system benefits, new mechanisms and/or incentives are required to encourage such investments.

The opportunity for greater interaction between energy vectors may also require different approaches to regulation in order to encourage and exploit synergies. Currently, regulation requires that electricity and gas networks are operated independently and there is currently no regulatory mechanism for incentivising interventions which deliver benefits across vectors – e.g. electricity and gas networks. The ETI has commented that "current governance and regulatory frameworks are simply not designed to enable and incentivise radical transformation". There is no regulatory framework for heating at present which exposes customers to potential cost risks and is potentially a barrier to investment. If stakeholders do not have a secure return on investment then cost of capital might be prohibitive.

Current network charging arrangements act as a potential barrier to maximising benefits of local community energy schemes and peer-to-peer trading. The ENA TSO-DSO project [68] has a workstream dedicated to network charging and Ofgem is aware of the need to ensure that wider network costs are appropriately and equitably shared across customers, including where communities become more self-sufficient in electricity production.

A more holistic approach to regulation across the energy sector might also reduce the risk of unintended consequences arising from changes to codes, legislation, policy and regulation (as discussed in the context of commercial barriers).

The regulatory framework needs to balance flexibility and agility with long-term certainty and stability

One of the reasons for adopting an eight-year price control was to give more longer-term certainty about revenues. Ofgem consider that this will better support innovation (by giving more certainty on rewards[1]) and signals an end to "short-termism" in the sector[2]. However, a longer price control increases the risk that market factors change, which might impact on regulated outputs and revenues. Within RIIO, Ofgem manages this through discretionary mid-period reviews (which allows for new outputs and material changes in outputs to be assessed) and uncertainty mechanisms (which are defined at the start of the price control). The ED1 Innovation Rollout Mechanism allows DNOs to submit cost-benefit analysis to justify additional up-front costs of rolling out innovation where it will deliver longer-term (beyond ED1) benefits.

This highlights the tension between achieving stability/certainty in the sector (which should encourage investment and drive down costs of capital) and flexibility/agility (which should allow for technological and market developments to be managed). It is possible that the pace and extent of change envisioned within FPSA may require a regulatory framework that can respond more flexibly to changing circumstances, e.g. through a shorter regulatory period or more mid-term review mechanisms. On the other hand, implementation of new functions may require more long-term certainty – for example, parties may be unwilling to invest in energy storage or Black Start capabilities if they do not have long-term visibility of future revenue streams due to the lack of long-term ancillary services contracts. Energy UK notes that: "*as electricity generation and supply needs long-term investment, it is vital the industry knows as much as it can about how great the demand will be in the future. It is essential the industry gets a clear signal of the focus, direction and speed of travel to 2030 and beyond*" [58]. Balancing the potentially competing requirements for investor certainty and sector agility will be a key challenge for power system regulation.

Lack of data access for new parties

The functionality defined within FPSA will involve greater collation and distribution of a wide range of new sources of data across the whole power system. This will include information about network assets and the performance of generation and energy resources, but could also include massive amounts of data about customers and the way in which they use data. This introduces potential risks around commercial sensitivity, data security and anonymity, particularly if sharing of data between multiple parties is required.

Data accessibility will therefore be subject to data security regulations which could present a barrier to some of the functionality within FPSA. For example, DNOs can currently access smart metering data, but there is a strict process which DNOs must go through in order to demonstrate that they need access to half-hourly consumption data to a given minimum level of aggregation. The need for access to higher granularity of data has been accepted by Ofgem [69] but DNOs must demonstrate that the level of aggregation of half-hourly consumption data that they adopt is sufficient to ensure anonymity.

Data accessibility may be particularly challenging in instances where non-regulated parties could benefit from having access to data.

6.4 Commercial framework

The 'commercial framework' barriers identified through our analysis mostly relate to commercial models that cannot be adopted under the current market structure. In many ways, these barriers are closely related the regulatory barriers identified above. The barriers can be summarised as follows:

- Existing commercial arrangements have unintended consequences that sometimes act counter to core policy objectives.
- Emerging and new entrant market participants are unable to participate in the market to realise benefits for the wider power system.
- New commercial models are required to deliver some of the functionality required by the power system.

[1] https://www.ofgem.gov.uk/system/files/docs/2017/01/guide_to_riioed1.pdf
[2] https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/decision-doc_0.pdf

These are considered in turn below:

Existing commercial arrangements have unintended consequences that sometimes act counter to core policy objectives

The existence of multiple policy objectives (i.e. the trilemma) means that sometimes industry participants are locked into commercial arrangements that might seem to work against certain policy objectives. An example of this is the capacity mechanism, which has resulted in thermal (diesel) generators being awarded contracts, sometimes long-term contracts. The mechanism meets one policy objective (security of supply), but potentially compromising (decarbonisation).

Existing contractual arrangements working against policy objectives in this way can be difficult to reverse (for example, through the existing industry change processes) resulting in a commercial ‘inertia’ that acts as a barrier to reforms.

Emerging and new entrant market participants are unable to participate in the market to realise benefits for the wider power system

The commercial options available to deliver benefits to the system are limited for some participants, especially in the more regulated parts of the value chain. One example of this is that only the SO generally procures ancillary services for system balancing services. DNOs’ involvement in procuring such services is generally limited to instances where procurement of services such as DSR is an alternative to costly network reinforcement. These resources are normally procured to meet a specific locational requirement, and there is no co-ordination to then maximise synergies that might be unlocked through use of such resources to meet further system needs. Distribution licences limit the ability of DNOs to act in this market or to procure services for subsequent re-sale to the SO [10]. This might lead to deviations from an optimal power system in some cases through conflicts and loss of synergies [10], [11], [8]. Greater co-ordination is being considered in the TDi innovation project [27].

Existing frameworks can also have a negative impact on the business case for new service providers that were not anticipated when the framework was put in place. An example of this is that the existing structure of network charges can impact negatively on energy storage business cases [8].

New commercial models are required to deliver some of the functionality required by the power system

In some cases, the barrier analysis presented in this report has identified power system functionality that might be delivered more effectively, or more efficiently, with new commercial models that cannot currently be delivered. In many cases the barrier is essentially one that results from regulation, and market participants simply require barriers to be removed so that they can implement new commercial models. One of the examples highlighted in the analysis is the absence of half-hourly settlements [29] although this should be implemented for all profile classes when smart meter rollout is complete. This leads to incentives not being aligned through the value chain, which in turn could lead to a sub-optimal allocation of resources across the sector.

New commercial models are also required to deliver functionality in the regulated segments of the value chain. For example, the barrier analysis identified that existing services may not be sufficient to support the system in the event of a Black Start, and new commercial models might be needed to meet these requirements. There may be an increasing need to recruit local generation and demand response given a significantly different generation and demand portfolio in 2030 than exists today. An Energy Emergencies Executive Committee (E3C) task force has been set up to consider changing needs for Black Start.

There is also uncertainty around the required level of customer engagement with the electricity system to deliver effective flexibility and ancillary services – and hence the construct of commercial frameworks that will provide the necessary incentives.

Finally, some new commercial arrangements may be complex to design and implement, and this complexity could itself be a barrier. Functions that require co-ordination between different parties could lead to concerns over how commercially sensitive data is treated, or over how conflicts of interest are tackled. For example, enhancement of the SO role through the Integrated Transmission Planning and Regulation (“ITPR”) project has required mitigation against the potential for conflicts of interest [7].

7. Conclusions

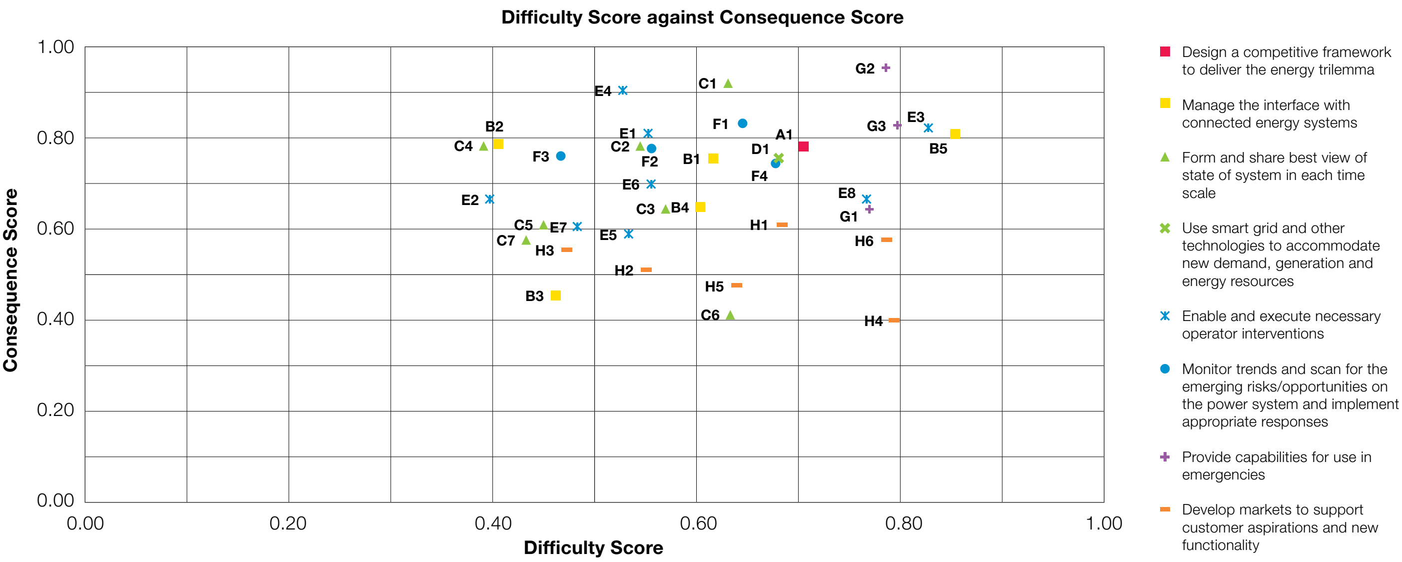
The impact analysis has demonstrated that there is a number of significant barriers to function implementation in today's power sector landscape that are not conducive to the timely delivery to these functions. The delay or non-delivery of these functions results in material consequences to system security, decarbonisation and affordability, ultimately risking delivery of GB energy policy. This is summarised in Figure 7-1 below where relative scores for function difficulty and consequence of non-delivery are shown by function grouping. It can be seen that these are clustered towards the top right, indicating relatively high difficulty and consequence and thus high relative risk to delivery of energy policy.

Impact analysis results also support development of Research, Design, Development (RD&D) and Innovation initiatives (see WP2) and pre-structuring of *Enabling Frameworks* (see WP4).

Specific barriers have been detailed and evidenced for each function and key implementation challenges, more broadly, explored. This has focused on the current approach to industry code governance, technical challenges to implementation, and existing regulatory and commercial frameworks.

Overall the analysis has demonstrated that the current power industry arrangements are not conducive to the timely delivery of the new or extended functionality identified by the first phase of the Future Power System Architecture Programme FPSA1. This has potential implications for achieving the goals of the Government's Energy Policy – i.e. a secure, affordable and low carbon energy future.

Figure 7-1: Function risk to delivery of energy policy by function groupings



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9. Annex A – Methodology

The impact analysis is based on classic risk assessment:

Risk Rating = Probability x Impact

which in the context of the impact analysis is:

Risk to Delivery of Energy Policy = Difficulty x Consequence (i.e. of late or non-delivery of functions)

where the difficulty of resolving the existing barriers correlates with the probability of the function not being delivered (due to inability of sector to overcome these barriers) and the consequences of not delivering the function correlates with the impact on energy policy of the function not being delivered.

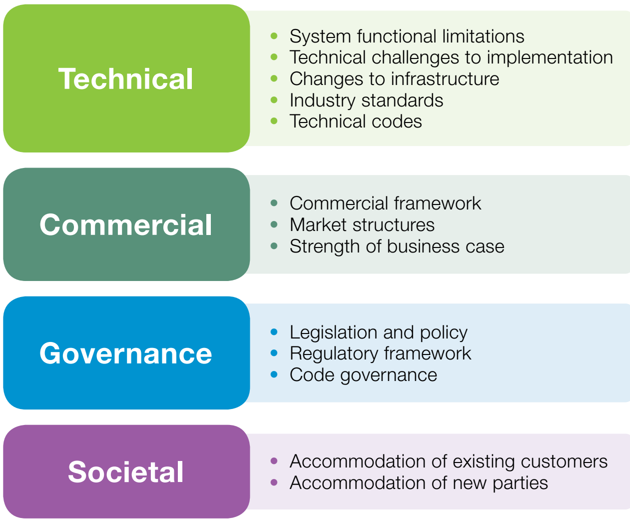
An immediacy parameter can also be included where 'immediacy' of the function is a simple way of indicating the sequencing of function delivery i.e. the order in which functions need to be delivered, considering interdependencies and the Evolutionary Pathway considered. Some functions will need to be prerequisites to other functions at a later stage. The Evolutionary Pathways defined in FPSA1 provide a broadly sequential function delivery path. However, in reality, there are likely to be many overlaps and interdependencies in function delivery, with functions delivered in parallel.

The inclusion of an 'immediacy' parameter in the risk calculation is not consistent with classic risk assessment. However, it enables us to consider function sequencing in prioritising removal of function barriers.

Risk to Delivery of Energy Policy = Difficulty x Consequence x Immediacy

Each function has been assessed on the basis of barriers and consequences. These are defined below.

Figure 9-1: Barrier categorisation



9.1 Barrier Definition

9.1.1 Technical

9.1.1.1 System functional limitation

Definition: Limits on the technical capabilities of the existing system prevent or deter implementation of the function. The delivery solutions for the function may not be compatible with the existing system.

Example: The ability of the existing system to manage complex control interactions could be limited due to insufficient monitoring and co-ordination leading to potential undesirable real-time interactions between actively managed networks.

9.1.1.2 Technical challenges to implementation

Definition: The extent of the technical change (models, processes) required to implement the function is significant and/or complex i.e. due to technical complexity and maturity of the delivery solution options.

Example: The sophistication of forecasting required (C4) is not presently available and the lack of both the required forecasting tools and algorithms is a barrier, as well as the ability to gather and process the necessary information and data from DER. There is also a lack of capability to analyse and interpret the information.

9.1.1.3 Change to infrastructure

Definition: The extent of change in infrastructure e.g. network assets, customer assets, required to implement the function proves significant and/or complex.

Example: Monitoring the effect of control interventions (E5) requires significant development of monitoring and communications infrastructure - integration into the existing infrastructure may be a barrier. Significant/complex changes to existing infrastructure are required to integrate more advanced control functionality.

9.1.1.4 Industry standards

Definition: Existing industry standards may prevent or deter the implementation of a function.

Example: The current standards may not presently (or fully) account for cross-energy vector co-ordination. Current safety standards (e.g. IEC 60335) may not account for additional risks associated with two-way communications and interface electronics incorporated with smart appliances.

9.1.1.5 Technical codes

Definition: The content of existing industry technical codes prevents or deters the implementation of the function. Codes may expressly forbid an aspect of the function from being implemented, requiring a derogation. Note that this refers to the codes themselves, rather than the change process for code.

Example: Changes required to grid code/distribution code to reflect interfacing and integration of local ANM schemes for example. Code changes to reflect DSO increased role for control.

9.1.2 Governance

9.1.2.1 Legislation and policy

Definition: Existing UK energy sector legislation and/or policy explicitly prevents or deters the function from being implemented. The function may be deterred because existing legislation results in high commercial or regulatory risk. Policy uncertainty may create an environment that inhibits investment in or a policy that is in direct conflict with the objectives of particular functions.

Example: Provide a mechanism for peer-to-peer trading. Legislative barrier - the 1989 Electricity Act may not allow peer-to-peer trading in its current form. Uncertainty regarding the policy direction concerning low carbon heat and the role of the gas network in future heat provision creates difficulties for forecasting of future demand and planning for increased integration between energy vectors.

9.1.2.2 Regulatory framework

Definition: Existing regulatory framework either prevents or deters the function from being established, and/or does not assign responsibility for establishing the function. Components of the regulatory framework that might act as barriers include licence conditions and regulatory price control approach and alignment.

Example: Licensing could act as a barrier to the introduction of new flexibility providers, such as electricity storage. Also, existing regulation does not address future co-ordination between a TSO and DSO.

9.1.2.3 Code governance

Definition: The processes for governance of electricity sector codes prevent or deter the function from being implemented.

Example: The change process for industry codes may not be agile or flexible enough to efficiently respond to rapid changes in the power sector.

9.1.3 Commercial

9.1.3.1 Commercial framework

Definition: Commercial frameworks to support the function do not exist, or are not appropriate for the function and/or are complex to implement.

Example: Contracts for existing services might be insufficient or even obstructive to development of new services. As an alternative example, it may be complex to design commercial arrangements that optimise the full scope of demand side response.

9.1.3.2 Market structure

Definition: The current structure of the market either prevents or deters the function from being established. Market structure might include trading arrangements, available trading platforms, or the assignment of responsibilities associated with operating the electricity market.

Example: Existing trading platforms and market rules may not support widespread introduction of peer-to-peer trading.

9.1.3.3 Strength of business case

Definition: Insufficient strength of the business case prevents or deters the function from being established, e.g. high initial or ongoing cost with long payback period and/or high uncertainty.

Example: Black Start services are becoming increasingly costly for a very low probability event. This may constrain the extent of market procured services in future.

9.1.4 Societal

9.1.4.1 Accommodation of new parties

Definition: Existing governance and processes within the power sector that specifically create barriers to entry to new parties (slight overlap with regulatory barriers recognised).

Example: Increasing local intervention in energy supply and distribution, including local energy supply companies, private wire or IDNO networks, microgrids etc. could potentially introduce uncertainty in wider network planning and forecasting processes.

Potential for large increase in new players that will need to get access to sector data - challenges in vetting/accreditation of new participants, maintaining appropriate commercial confidentiality and ensuring sufficiency of data and cyber security.

9.1.4.2 Accommodation of customers

Definition: Existing customer attitudes and behaviour (or lack of awareness) may prevent the implementation or undermine the effectiveness of particular functions (i.e. lack of public acceptance).

Example: An unwillingness on behalf of consumers to adopt flexible energy tariffs or to allow automated demand of electrical appliances in their homes could limit the effectiveness of dispatchable demand as a means of managing network demands, balancing and ancillary service provision.

9.1.5 Scoring definitions - Barriers

High: Overcoming obstacles would require considerable change to the current functioning of the power sector.

Medium: Overcoming obstacles would require some moderate changes to the current functioning of the power sector.

Low: Overcoming obstacles would require limited changes to the current functioning of the power sector.

Level of change to the power sector can be characterised by the magnitude, complexity and/or difficulty of the change required and/or the number of changes required.

9.2 Consequences

9.2.1 Affordability

Inefficient operational costs: Failure to implement the function leads to comparatively higher total cost of dispatch of energy and ancillary services.

Inefficient investment: Failure to implement the function leads to investment in network assets that could otherwise have been deferred or avoided and/or existing network and customer assets being less efficiently utilised.

Impediments to new business models: Failure to implement the function means that new, innovative business models that release value are not widely adopted.

9.2.2 Decarbonisation

Accommodation of low carbon generation: Failure to implement the function reduces the ability of the power system to further accommodate low carbon generation (e.g. wind, solar, marine etc.).

Accommodation of low carbon demand: Failure to implement the function reduces the ability of the power system to further accommodate low carbon demand (e.g. heat pumps, electric vehicles etc.).

9.2.3 Security of supply

Security of energy supply: Failure to implement the function puts the overall security of energy supply for GB consumers at increased risk.

Reliability of networks: Failure to implement the function decreases the reliability of the networks e.g. increased failures due to overloads and/or prolonged restoration time.

Maintaining system stability: Failure to implement the function has an adverse impact on the operability of the power system (e.g. voltage, stability, thermal constraint).

9.2.4 Scoring definitions - consequences

High: Consequence is relatively severe in terms of impact on cost, security of supply or ability to meet decarbonisation targets e.g. significant impact on the general public.

Medium: Consequence is relatively moderate in terms of impact on cost, security of supply or ability to meet decarbonisation targets e.g. material impact but limited awareness within general public.

Low: Consequence is relatively limited in terms of impact on cost, security of supply or ability to meet decarbonisation targets.

9.3 Barrier prioritisation

Barrier category prioritisation i.e. the barriers that are most prolific and significant across all functions, has been assessed as a key output. This provides an indication of the types of barriers that are likely to require prioritisation to remove. Barrier specificity is then detailed against each function in the impact analysis model.

9.4 Sensitivity analysis

A number of sensitivity scenarios have been assessed including the following:

- In addition to calculation of overall barrier difficulty based on the average of all barrier category averages as a baseline, a further approach was to apply the maximum of all barrier category averages (i.e. difficulty score = max [average difficulty score for: technical, commercial, governance, societal]). This takes into consideration the fact that even a few high difficultly barriers may significantly impact the implementation of a function (although the number and relative difficulty of all barriers is also important).
- Overall consequence impact is based on the average of all consequence impacts, assuming that all consequences may occur if the function is not implemented.
- The influence of the Evolutionary Pathways developed in FPSA1 has been explored e.g. community empowerment, power sector leadership.

A number of sensitivity cases were assessed and the impact on barrier prioritisation was found to be minimal.

9.5 Review and verification process

A review and verification process was developed and applied to ensure that the final results are robust, defendable and not significantly influenced by individual or group biases.

This includes internal review (bottom-up and top-down) within the WP3 team and with the WP3 champion. A lighter-touch revisit of the review in order to include new or modified functions and ensure alignment with function needs and delivery options for WP2 was undertaken.

The peer review process with the wider FPSA2 team has included a detailed review of three test case functions and corresponding function barrier specifications considering function needs and delivery options identified in WP2.

9.5.1 Evidencing

Evidencing for function barriers is based on a number of publically available industry reports as well as incorporation of learning from FPSA1. Market barriers identified in WP1A have also been considered and these closely align with function implementation barriers, although not in all cases.

10. Annex B – Impact Analysis Model

'The Impact Analysis Model' is available as an Excel Workbook which is obtainable as a free download from the **www.theiet.org/FPSA**

Future Power System Architecture Project 2

Final Report

Work Package 3: Impact Analysis

The full set of FPSA2 documentation including the Main Synthesis Report, Policy Briefing paper and individual Work Package Reports are available online via the Institution of Engineering and Technology and the Energy Systems Catapult.

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