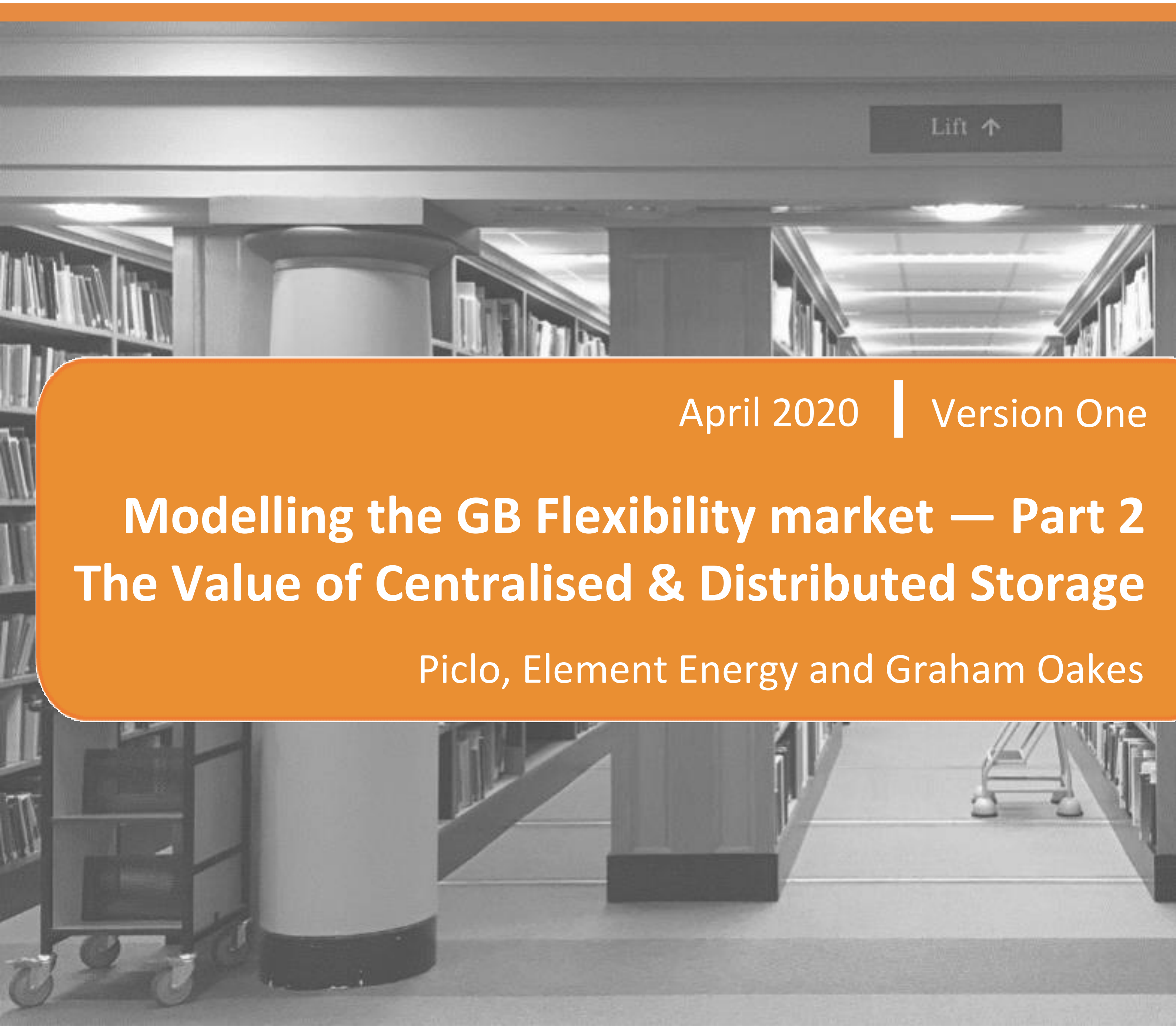
Local Energy Oxfordshire



April 2020 | Version One

Modelling the GB Flexibility market — Part 2
The Value of Centralised & Distributed Storage

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Contents

Executive Summary

This study set out to assess the value and whole-system impact of demand-side flexibility in a net-zero carbon energy scenario for the UK. An accompanying report ("The Value of Flexibility") examines the overall value of such flexibility. In particular, it explores the degree to which flexibility in general can reduce the need for investment in traditional solutions such as thermal peaking plant and network reinforcement.

During the course of the study, it became clear that different types of flexibility can provide different types of value yet may compete with each other for deployment. This report explores this competition by taking two specific flexibility vectors – centralised, utility-scale storage versus distributed storage as exemplified by V2G-enabled electric vehicles – and examining the possible path dependencies that competition between them may create for a successful Energy Transition.

Our analysis has produced the following key results, which are discussed in more detail in the body of this report.

1. Flexibility can generate significant savings across the system. The accompanying report identifies that it could reduce overall electricity system costs by more than £4.5bn per annum. This benefit comes from a combination of avoided network investment, reduced need for peaking generation and reduced curtailment of renewable generation.

2. Network savings are maximised by widescale deployment of distributed storage, as exemplified by V2G-enabled electric vehicles in this study. A large, distributed asset base, such as would be available with roll out of EVs across the nation, is required to maximise the benefits of flexibility, especially on the LV network. Grid-scale[1] storage is not deployed at the edge of the network so cannot provide as much benefit there.

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[1] For this report we consider "distributed storage" to be that which is connected at lower voltages on the distribution network, exemplified by V2G-enabled EVs but also including systems such as behind-the-meter batteries on domestic and commercial sites. "Grid-scale storage" is that which is connected at higher voltages or on the transmission network, exemplified by battery systems of MW-scale and above. There is potentially a grey area where these two definitions overlap, but in practice the bulk of the storage deployed will probably fall clearly into

3. Grid-scale and distributed storage will compete with each other for other value streams. As more flexibility is deployed, supply/demand imbalance is reduced, which reduces the marginal value of additional flexibility. This means that technologies which are established early may come to dominate the early value streams and so prevent later technologies developing economies of scale and standardisation. As value streams from ESO services and energy trading are better developed than those from DSOs, this tends to favour deployment of utility-scale, centralised storage.

4. This creates a path dependency which may cause the system to converge on a suboptimal solution, with grid-scale storage capturing so much value from the market that distributed storage may struggle to gain a foothold. That could lead to DSOs spending more than is optimal on traditional network reinforcement.

5. These path dependencies are exacerbated by the imbalanced trade-off between the risk of asset stranding versus the risk of novel flexibility solutions. DSOs must manage both risks –network assets that may become stranded if they overinvest in traditional reinforcement; or not delivering on their licence obligations if novel flexibility solutions do not deliver as expected. However, the former risk is socialised through regulatory charging controls while the latter is not. This imbalance also tends to favour traditional, centralised solutions. Managing it effectively will be critical to achieving a net—zero system in the most economical way.

This report builds from the companion, "Value of Flexibility", report, in which the key findings are:

1. Hitting net-zero requires significant investment in low-carbon generation, demand-side technologies and electricity network capacity. Flexible demand will have a significant impact on system costs and capacity.

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one category or the other. We also note that storage will compete with other technologies for many applications – demand side response, traditional network reinforcement, etc. To keep the discussion simple and so help clarify the types of path dependencies which may arise, we have focused on these two solutions. The real world will be more complex, but nonetheless will need to deal with dilemmas such as we highlight here.

2. A ‘passive’ approach to demand management represents the most expensive decarbonisation configuration in 2050. It also requires the greatest investment in expanding generation and network capacities. From a cost and feasibility perspective, continuing with a business-as-usual approach represents a higher cost and higher risk pathway than those which incorporate more flexibility.

3. Compared to a passive approach, flexibility can reduce the whole-system cost by £4.55bn per annum by 2050. Wider deployment of energy storage systems could extend this benefit to £5.0bn per annum.

4. Compared to the passive approach, flexibility is not only fundamental for achieving a viable capacity build-out to 2050 but delivers benefits across the power system, including:

    a. Reduced investment in and utilisation of expensive peaking plants (~15GW reduction).

    b. Reduction of dispatchable generation by 22TWh per annum.

    c. Reduced curtailment of low marginal cost renewable generation by 30TWh per annum.

    d. Reduced network investment. Flexibility could reduce network reinforcement by two-thirds.

5. Deployment of flexibility and renewable energy sources is synergistic and should be part of any coordinated plan to achieve net-zero.

1. Introduction

We know that the implications of demand-side response in a decarbonised energy system can be profound. Existing research has outlined the imperative for flexibility on the demand side in a decarbonised system that's based on variable renewable energy sources[2] (rather than nuclear). And other studies have illustrated that flexibility is a key determinant between the lowest and highest cost net-zero electrification pathway[3].

However, there are some limitations in prior work in this sector which we sought to address in this study. Firstly, the extent of demand-side flexibility is often assumed, for example expressed as a percentage of peak or daily demand. This approach fails to reflect the attributes and environment of flexible assets and the characteristic behaviour, if applicable, of consumers.

In this study, we took the approach of basing flexibility potential on real-world principles such as typical demand for electric vehicles and daily mileage and desired temperature of homes and buildings that are affected by heat loss and weather patterns. The level of flexibility delivered then emerges from the system analysis. This type of simulation improves our confidence in predictions for the scale of flexibility that's available from space heating and transport for example.

Secondly, many studies do not place equivalence on flexibility from supply and demand in managing power grids. This study deploys a whole-system model which couples demand and supply to test the scope for flexibility to optimise network asset utilisation and investment. The approach encompasses generation, networks, and flexible and inflexible demand from multiple sectors.

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[2] Power sector modelling: System cost impact of renewables Report for the National Infrastructure Commission, Aurora Energy, 24 May 2018

[3] Towards fossil-free energy in 2050, conducted by Element Energy and Cambridge Econometrics, March 2019

A variety of flexibility scenarios were developed to test our assumptions. These were based on a net-zero model that was built upon National Grid's Community Renewables scenario[4], modified to incorporate flexible assets such as smart EV and heat, utility-scale battery storage, and vehicle-to-grid (V2G) technology.

A whole-system model, including dispatchable and variable renewable generation sources, network- and demand-side, was created to identify the realistic potential and optimum contribution of demand flexibility to reduce whole-system costs.

The objective of the analysis was to estimate the full potential for flexibility from smart demand management in a decarbonised electricity system. By exploring the potential for flexibility at scale, we set out to understand the value - for economic and system benefit - of investing in flexibility services now.

In the course of this study, it also became clear that different types of flexibility provide different, but overlapping, types of value. This potentially creates competition between different flexibility sources and path dependencies in their deployment. That is what this report examines.

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[4] National Grid, Future Energy Scenario - Community Renewables 2019

2. Flexibility scenarios and modelling approach

2.1. Creating a net-zero Baseline Scenario

To isolate the scale and impact of flexibility on the energy system, we drew upon a widely-available scenario for decarbonisation, National Grid's Community Renewables model from the 2019 Future Energy Scenarios (FES)[5].

We chose this scenario as the basis for our analysis because it achieves the 2050 decarbonisation target in a decentralised energy landscape and includes assumptions for a high degree of energy efficiency, which is required to achieve efficient net-zero carbon residential heating.

However, although Community Renewables incorporates participation and activity on the demand side to manage the grid, the scenario is not zero-carbon (the scenario reaches an 80% emissions reduction target by 2050).

To remedy this, adjustments were made to remove fossil fuels from supply and end-use technologies, as outlined below. Henceforth, we refer to the net-zero Community Renewables scenario as our Baseline scenario.

Adjusting demand to net-zero

The Community Renewables scenario assumes 5.2m natural gas boilers in 2050. These must be replaced with zero-carbon heating systems for a fossil-fuel free scenario. To adjust the demand, we built on recent analysis undertaken for the Committee on Climate Change (CCC) for residential heating that meets net-zero carbon targets[6].

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[5] Future Energy Scenarios 2019, National Grid, July 2019

[6] Net Zero Technical report, Committee on Climate Change May 2019

In our model, natural gas boilers are replaced with a mixture of air source heat pumps (ASHP), powered by electricity and hybrid heat pumps which combines a heat pump and gas condensing boiler to optimise energy efficiency. This implies a requirement for decarbonised gas (Hydrogen H2), which, compared to a scenario comprised of electric heat pumps only, already incorporates a degree of flexibility in heat demand related to the shiftable demand associated with the production of hydrogen gas.

The original and final configuration is illustrated below, and the CCC central scenario is included for reference.

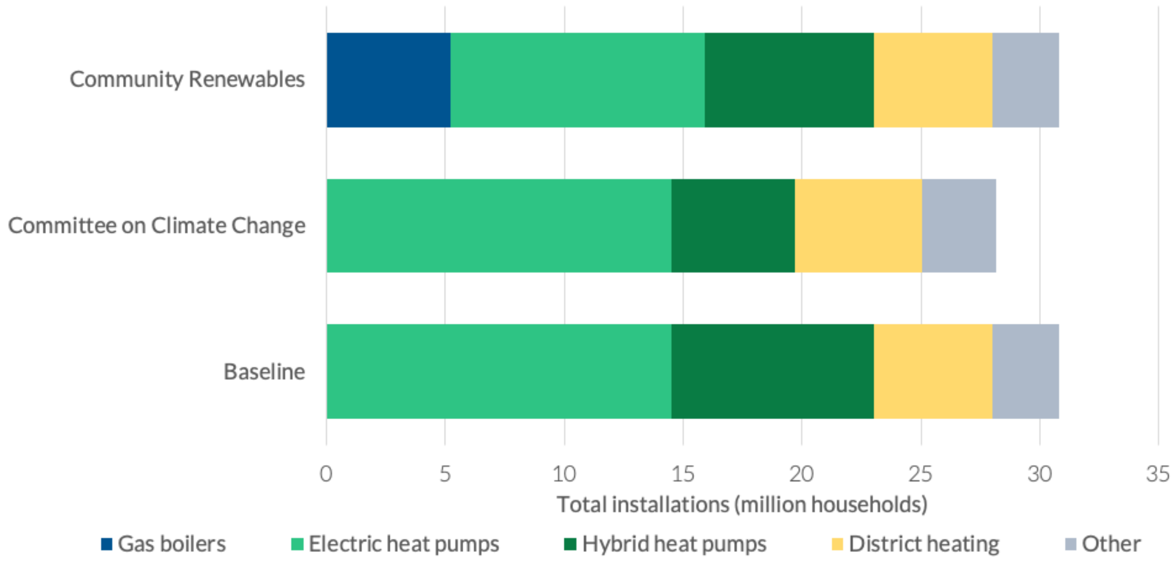

Figure 1: Comparison of heat demand scenarios in 2050, including our Baseline scenario.

Adjusting supply

The Community Renewables scenario retains capacity from fossil-fuel thermal power plants to provide supply flexibility in the form of backup dispatchable generation.

In the adjusted scenario, biomass and carbon capture, utilisation, and storage (CCUS) power plants are used to provide dispatchable generation capacity as an alternative to thermal power plants.

Reducing reliance on dispatchable low-carbon thermal altogether would increase system reliance on demand flexibility above the figures estimated in this report.

There is an increase in underlying demand due to the deployment of heat pumps to displace gas boilers. Consequently, supply capacities are adjusted upwards to maintain the share of renewable generation in the system.

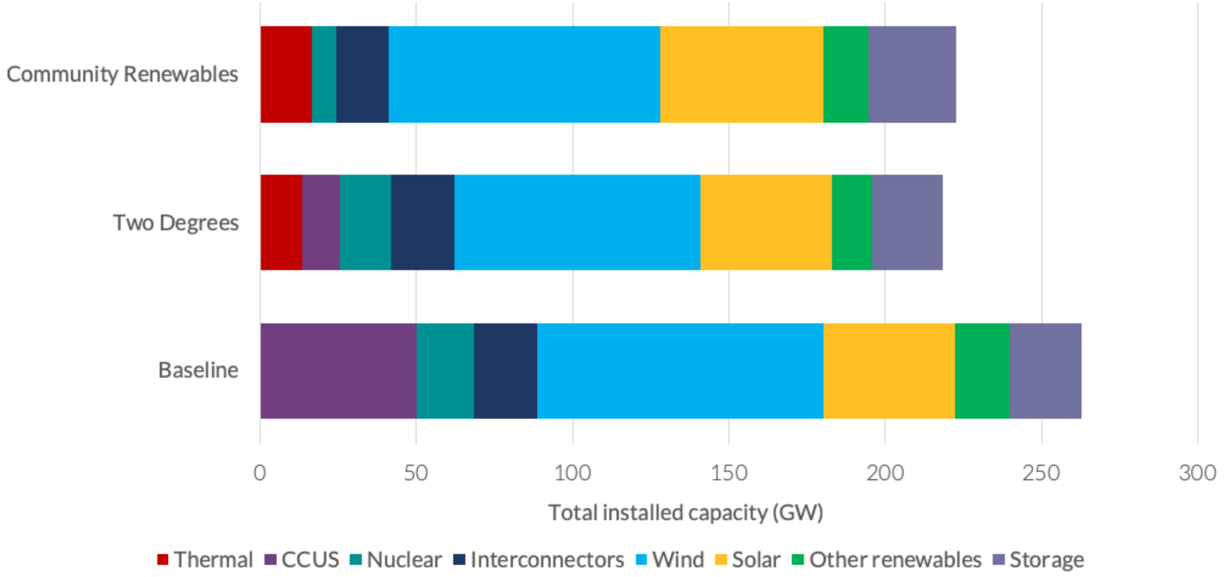

Figure 2: Comparison of projected energy supply scenarios in 2050.

2.2. Flexibility Scenarios

The Community Renewables 2050 scenario includes a range of flexibility assets, assuming a high level of consumer engagement and much-improved building efficiency. The flexibility sources included are:

- Industrial and Commercial (I&C) DSR of 6.7 GW (~14% of peak demand)

- Residential DSR of 1.6GW, including district heating (~5% reduction of peak demand)
- Smart EV charging (~50% reduction in peak demand)
- V2G generation (2.9m vehicles providing 10GW contribution at peak)
- Grid storage (28GW contribution at peak, including 40GWh from utility-scale battery storage and 91GWh pumped-storage hydroelectricity)

Baseline

In our Baseline scenario, the underlying level of DSR flexibility from I&C and residential electricity (non-heat related) outlined above are unchanged. However, contributions from smart EV charging, grid storage and V2G generation are removed.

These changes leave a demand side comprised of largely passive electric transport and electric heating that represent a continuation of business as usual.

In the following flexibility scenarios, we modify the remaining sources of flexibility to adjust peak demand and supply.

Basic Flexibility

Smart EV charging (but not V2G) is dispatched dynamically. The starting point is the passive daily demand profile where drivers plug in their vehicles to charge when they arrive home. In our Smart scenario, charging demand is adjusted for system benefit, while ensuring vehicles achieve the required state of charge in the morning.

Smart heat: electricity consumption from space heating is adjusted dynamically for system benefit while ensuring target internal heating temperatures are met.

A small percentage of Industrial and Commercial demand flexibility is added (5%).

Grid Storage

Smart EV and heat are adjusted dynamically as outlined in the Basic Flexibility scenario.

Utility-scale battery storage is deployed to a level where the marginal economic cost equals the marginal system benefit. This is deployed in addition to smart EV and heat so the economic level of battery deployment is lower than if these other flexible assets were absent.

Vehicle-to-Grid

Smart EV and heat are adjusted dynamically as outlined in the Basic Flexibility scenario. Distributed storage within EVs is deployed as outlined in the Grid Storage scenario.

In addition, V2G deployment (i.e. switching from a smart charger to V2G) is increased to the point at which the marginal cost is equal to the marginal system value gained by deployment.

We developed separate scenarios to explore how the dispatch and control of V2G can impact the service provided. V2G assets are modelled providing two distinct services to the power system, either by operating in a generation capacity avoidance or network-responsive mode.

- V2G gen - 75,000 generation-optimised electric vehicles (generation capacity avoidance mode)

- V2G net - 7million network-optimised electric vehicles (network-responsive mode)

2.3. Modelling Approach

Integrated Supply Demand Model (ISDM) is an energy model that was developed to determine the optimised configuration and operation of power systems with high penetration of renewable energy sources to ensure the security of supply.

For the purpose of this report, ISDM was selected because it operates as a whole-system model which includes the dispatch of generation assets (to abide by network constraints), and demand-side flexibility where available. It includes a range of flexibility assets, and the degree to which associated demand can be shifted, as shown below.

Heat pumps	**Up to one day**
Electric vehicle charging	**Typically one day, or optionally over several days**
District heating and resistance heating	**Up to one day**
Flexible power applications	**Up to one day**
Storage (batteries)	**Several days**
Power to gas	**Weeks or months**

Table 2: Time period by which flexible demands can be shifted.

ISDM allows us to project the availability of flexibility based on the demand assets themselves and their environment. This factors in the attributes of the assets to ensure adequate service delivery. For example,

- Flexibility from EVs accounts for daily driving demand, alongside EV efficiency and battery size.

- Flexibility from space heating factors in both the target temperatures of buildings and attributes such as the fabric of building and heat loss, as well as the local environment (e.g. hourly outdoor air temperatures).

This sophisticated simulation of the demand side means that flexible demand assets can be dispatched dynamically in the model to reduce overall system costs.

3. Key results

3.1. Summary: the value of flexibility

The companion report, "Value of Flexibility", describes the following core findings in more detail:

- Flexibility could reduce network investment to 2050 by 50%. Our Baseline model gives a net-zero electricity consumption of 465TWh per annum. Electrification of heat and transport adds a significant component to loads, raising the peak network demand from the current ~60GW to 91GW. Under the Basic Flexibility scenario, demand side flexibility provided by a combination of DSR, smart heating and smart EV charging (but not V2G) reduces peak demand to only 75GW, thus reducing the amount of network reinforcement that might be needed by ~50%. Flexibility achieves this by shifting demand away from peak times and holding a more constant level of demand throughout the demand cycle, thus giving much higher utilisation of existing network assets. Average utilisation of the network is increased by circa 10%, which translates to greater revenue per unit of network capacity installed.

- Smart demand reduces peak dispatchable capacity by 17GW. The Baseline scenario requires ~67GW of dispatchable generation capacity to backup the system during periods of peak demand. This is lower than the peak network load because some renewable generation offsets the total amount of generation that is required. In the model, this dispatchable generation is predominantly supplied by combined cycle gas turbine (CCGT) plant, backed by carbon capture, use and storage (CCUS). In the Basic Flexibility scenario, flexible demand both reduces peak dispatchable capacity by 17GW and increases the run hours of the remaining capacity. The net result is to reduce the requirement for thermal generation by 22TWh/year while improving the economics of that plant which is required. Adding utility-scale storage improves these numbers further, for example giving an additional 2.4GW reduction in peaking generation.

- Demand flexibility reduces curtailment of renewable generation by 30TWh p.a. As well as reducing peak load on the network and the amount of peak dispatchable generation required, flexibility also reduces curtailment of renewable generation by shifting load into times when renewable energy is available. The flexibility scenarios examined in this study were able to reduce curtailment of renewable energy by up to 30TWh/year versus the Baseline scenario. This reduces curtailment of variable renewable generation from 21% to 14% of annual generation, a significant improvement on revenue and economic viability of these energy sources.

- The overall benefit of flexibility could exceed £4.5bn per annum. We estimate that the Basic Flexibility scenario has the potential to reduce annual system cost by £4.55bn, with savings from avoided network capacity, reducing peaking generation capacity, and reduced curtailment of renewable generation which in turn reduces fuel use. Widespread deployment of storage could extend these savings to £5bn p.a.

3.2. The potential for path dependencies as flexibility markets grow

Flexible assets including demand response and batteries can reduce the discrepancy between supply and demand. However, as more flexibility is deployed, supply/demand imbalance is reduced which can reduce the value of subsequent flexibility capacity.

The reducing marginal value creates the potential for increased competition between these assets. For example, figures 4.1 and 4.2 below show the performance on the peak day for the Grid Storage and V2G-gen scenarios respectively. The similarity between the profiles is striking. We found that 5GWh of transmission connected battery storage could economically displace 2.4GW of peaking generation. Or V2G could deliver similar benefits: 750,000 V2G-enabled electric vehicles could provide 15GWh of behind-the-meter storage and economically displace 3.8GW of peaking generation.

However, utility storage and V2G are at different stages on the technology maturity curve, and at different stages in the development of business models for their deployment. Thus, there is a strong likelihood that one will become established before the other, with the reducing marginal value then making it harder for the second to enter the market at scale.

This creates path dependencies which may have implications for wider policy: if utility-scale storage dominates the market, then what does this mean for the national EV rollout, for example? Are we happy to forgo the additional 1.3GW reduction to peaking generation that V2G enables? And as the next section shows, V2G can provide benefits at the edge of the distribution network that transmission-connected storage cannot address – are we happy to accept the additional network investment that might be required without V2G?

(Note also that these levels of storage deployment come after other demand side flexibility options have been dispatched, as per the Basic Flexibility scenario. Far greater storage levels would be economically deployable in the Baseline scenario, though this would come at significant additional cost to the electricity system and bill payers).

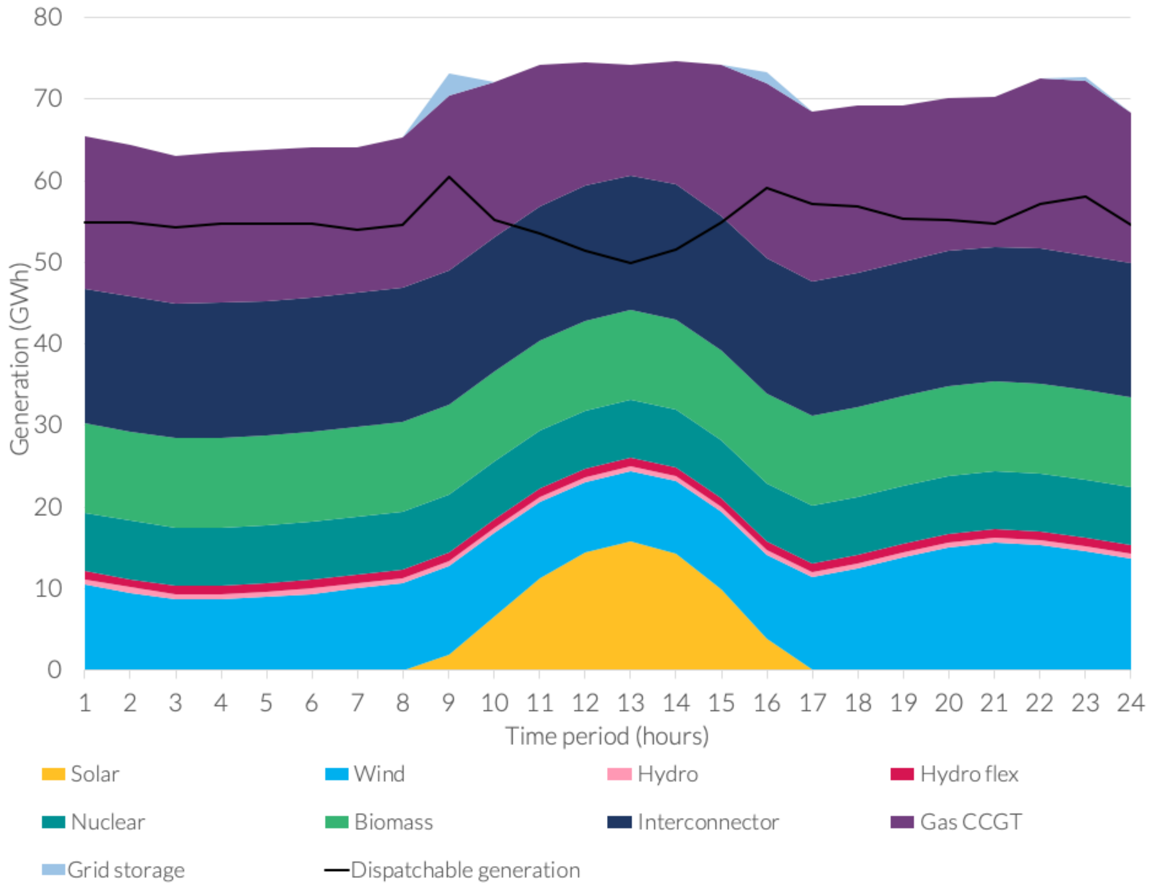

Figure 4.1. Grid Storage: 5GWh of utility-scale storage can economically displace 2.4GW of peaking generation.

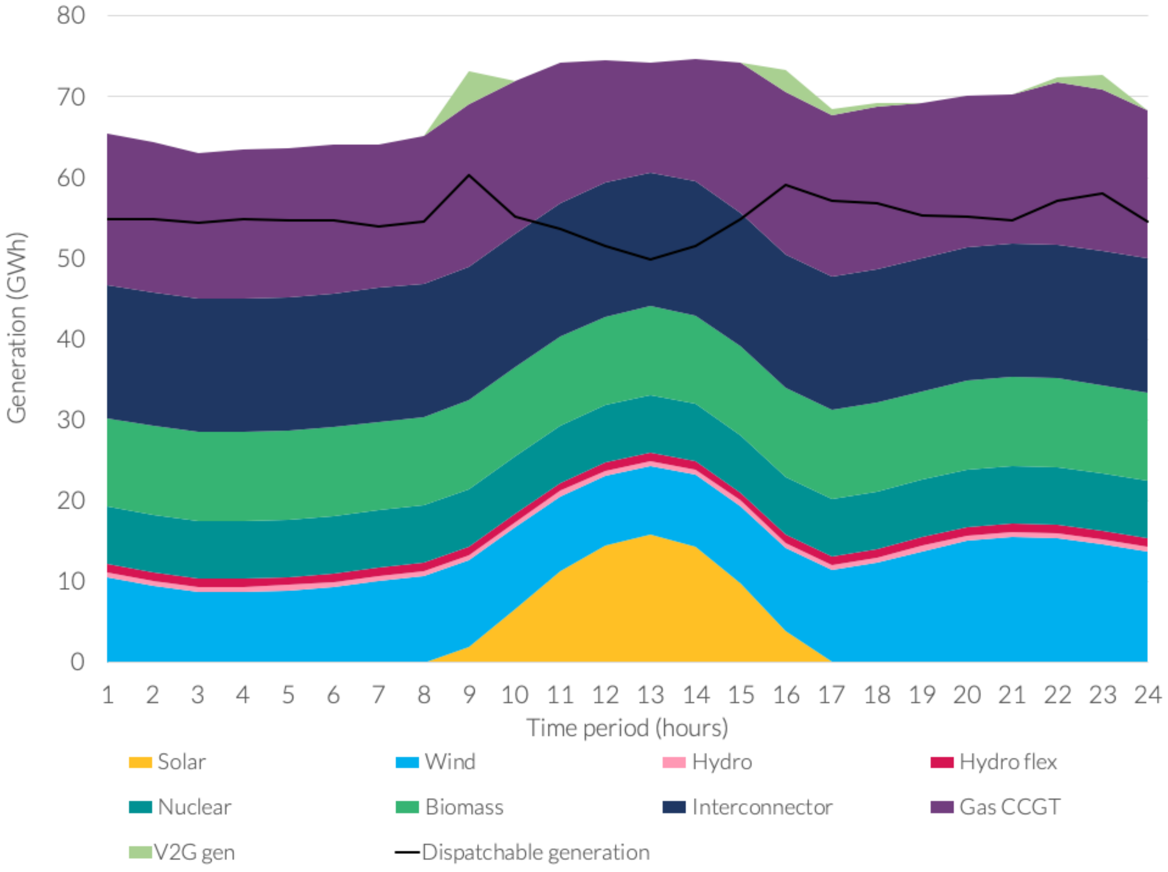

Fig 4.2. V2G-gen: 15 GWh of V2G can economically displace 3.8GW of peaking generation.

3.3. Analysing the impact of distributed storage at the edge of the network

Flexible assets can provide savings across the power system. The way in which these assets are controlled will determine the size and distribution of the savings.

In figure 4.3, V2G assets are deployed until their cost equals the marginal benefit of displacing peaking generation. As with figure 4.2, 750,000 V2G-enabled EVs operate at times of peak dispatchable generation for short periods. The result is that 15GWh behind-the-meter storage can displace 3.8GW of peaking generation.

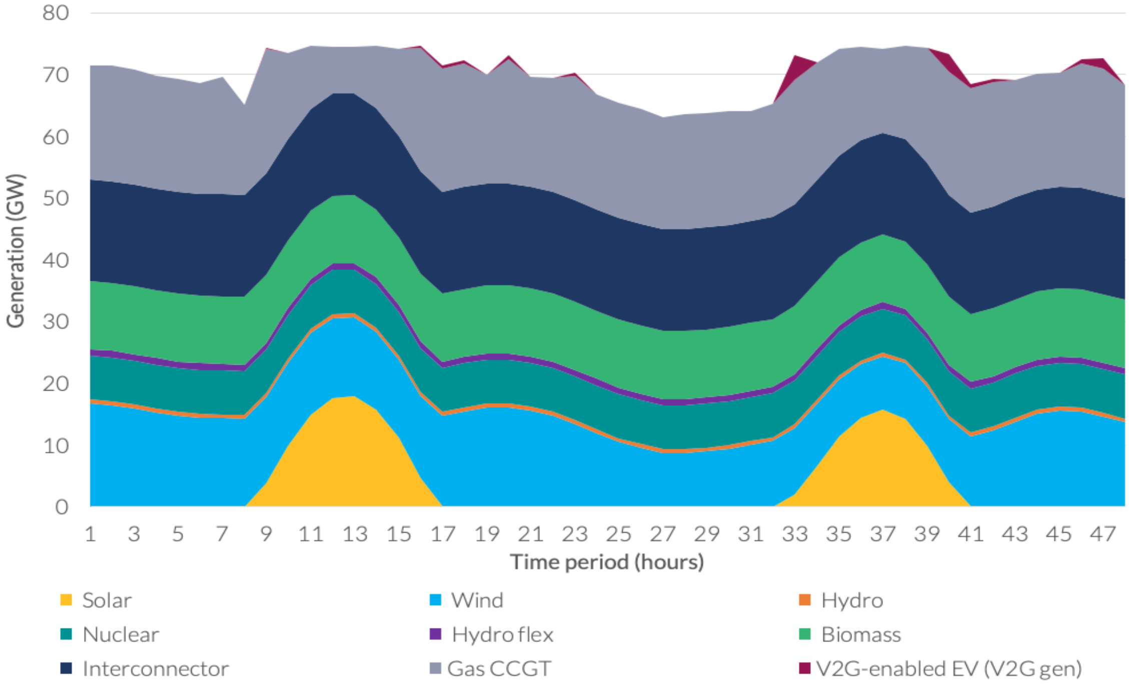

Figure 4.3: V2G assets optimised for the benefit of generation over two days (48 hours) are deployed here to reduce dispatchable peaking plant capacity by ca. 4GW.

Although this displacement is impressive, this operational profile is not effective in reducing peak network demand. This is because the peak network demand profile, after flexibility, has contiguous periods of high demand with a duration of 15-20 hours. To reduce network demand, V2G assets need to provide flexible capacity over this duration. When valued against network capacity savings, and after factoring in the cost, V2G can provide savings up to a duration of 30 hours, as shown in figure 4.4. We estimate that 7 million V2G-enabled cars (~20% of the anticipated EV fleet in 2050) can be economically deployed to provide 140GWh of storage (20kWh per vehicle). This could reduce the peak network requirement (after flexibility) by 5GW and dispatchable generation capacity by 3.8GW. Note that this constitutes an approximate ten-fold increase in the V2G storage capacity to provide these network benefits.

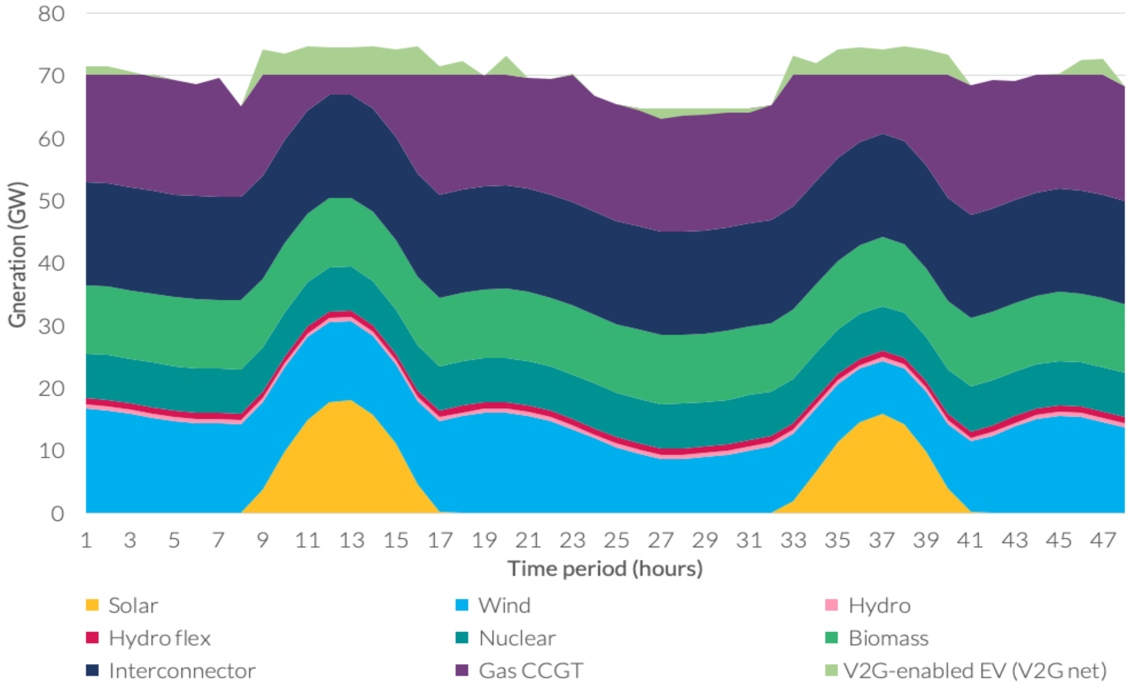

Figure 4.4: V2G assets optimised for the benefit of the network over two days (48 hours) shows that longer duration V2G assets are required to reduce network loads by ca. 5GW

3.4. To capture whole system benefits, we must manage path dependencies

Table 4.1 analyses the potential value streams that can be addressed by centralised (utility-scale) and distributed storage (exemplified by V2G in this report, but also applying to technologies such as fixed batteries deployed on domestic and commercial sites). It can be seen that each type of storage provides a different mix of benefits. The ideal system therefore probably contains a mix of both, with the exact proportion of each determined by factors such as how we decarbonise heat, uptake of EVs versus modal shift in transport, etc. While deep uncertainty remains over these future pathways, there is also significant optionality value to supporting both technologies.

The issue right now is that these value streams are in varying stages of development. Broadly, ESO Ancillary Services and Energy Trading Services are well developed (especially for utility-scale solutions; National Grid's "Residential Response" project is addressing some of the questions of opening them more fully to smaller, distributed solutions), while network services are still in early stages of definition, e.g. being driven by the emerging DSO transition. This gives an inherent advantage to grid-scale storage, which is better suited to address the existing value streams.

That creates the risk that centralised storage will come to dominate value streams that are essential for distributed storage to include in its "value stack" if it is to become economically deployable. That is, the system risks converging on a solution where grid-scale storage captures more of the ancillary service and energy trading revenue streams than is optimum from an economic or system perspective, simply because it got established first and so prevented distributed storage developing its own economies of standardisation. This trend may be exacerbated if system operators and regulators tend to overly reward established technologies over emerging ones.

This has two potential consequences:

1) Without access to significant volumes of edge storage (and the flexibility it provides to the network, especially at lower voltages), DSOs will be forced to invest in traditional network reinforcement to meet demand. This risks creating a "spiral of decline" for edge storage – as DSOs reinforce the network, the value storage can capture from distribution network services declines, and so its deployment becomes even more constrained. This pushes the system further away from the economically optimum point.

2) Early-adopter consumers cannot capture the direct benefits associated with edge storage. This lessens their likelihood of investing in V2G-enabled EVs and infrastructure, home batteries, etc, or at least creates pressures to defer their investment decisions. That slows down the deployment of low carbon technologies, decreases the value of critical early adopter markets to innovators, and reduces people's engagement in the energy transition. All three of these factors will make it harder to transition to net-zero.

None of this negates the value of centralised grid-scale storage. It provides many benefits and will clearly fill a valuable position in the future energy system. But it does suggest that to ensure we have the right mix of options available for the future energy system, policy makers may need to provide more explicit support for decentralised V2G and storage solutions until network value streams are fully developed.

Value Stream	**Centralised Grid-Scale Storage**	**Distributed Storage (e.g. V2G, domestic batteries)**
Ancillary Services to ESO	✓✓✓ • Administratively simple • Low data requirements • Aligns to ESO's existing expertise with large, central, deterministic infrastructure • Economies of scale for small numbers of large sites	✓ • Technically feasible, but requires systems to handle additional administrative and data management overheads • May be inaccessible due to active network management at intermediate layers of network • Requires expertise in distributed, stochastic assets • Economies of standardisation for large numbers of small sites, but these take time to get established
Energy Trading services	✓✓✓ • As for ESO services – fits well with existing models	✓ • As for ESO services – technically feasible, but requires systems, expertise and

	and expertise, and benefits from economies of scale	economies of standardisation to become competitive - Incurs distribution network costs, so can only be viable if it is a supplementary revenue stream where these costs are covered by other uses
Transmission Network Services (Constraint and Fault management)	✓✓ - Fits well with existing models and expertise, but not yet proven at scale	✓ - As above, technically feasible, but requires systems, expertise and economies of standardisation to become competitive - Incurs distribution network costs, so can only viable as a supplementary revenue stream
Distribution Network Services (Constraint and Fault management)	✓ - Whilst it is possible to provide DSO services on higher voltage levels (typically 33kV+), assets are not likely to be situated in the right locations. - Not feasible at low voltage networks	✓✓✓ - Although the issues with systems and expertise remain, only distributed storage has the right granularity and location on the network to address these issues
Consumer Benefit	Indirect – reduces overall system costs, which flows through to consumers via regulated pricing	Provides direct benefit (lower energy costs) to participating consumers and communities, as well as indirect benefit to all consumers

Table 4.1: Value Streams for Centralised and Distributed Storage

4. Conclusions

4.1. Flexibility generates significant savings across the system

As shown in the companion report, "The Value of Flexibility", introducing flexibility via demand-side response and smart charging can reduce overall electricity system costs by circa £4.55bn/year. These savings arise throughout the system, comprising ~£2.7bn avoided network capacity, £0.75bn in avoided generation peaking capacity, and ~£1bn from reduced curtailment of renewable energy.

All our scenarios indicate that significant network investments will be required. However, flexibility can reduce the associated cost by 50% (network investment to handle an additional 30GW is required in a passive scenario, versus 15GW in a flexible scenario). Flexibility will be a key element in ensuring the build-out of network expansion to 2050 is feasible.

Backup from dispatchable generation is required to support an expanding system, even when flexibility of demand can reduce the peak by 15GW. Avoiding investment in low run-hour peaking plants brings significant system savings.

Flexibility can be effective in reducing the curtailment of variable renewable energy sources. The analysis predicts that 30TWh of VRES can be accommodated, which represents 10% of the potential (uncurtailed) annual output. This would reduce policy costs associated with curtailment-related payments to renewable generators.

4.2. Network savings are maximised by distributed storage

We found that to reduce peaking plant capacity by 1GW requires flexibility assets to maintain this capacity for 2-3 hours. To reduce network capacity by the same amount requires much longer duration of storage. This is because flexibility has already flattened the peaks in demand; the typical duration of peak loads after flexibility may be 20 hours or more, requiring an equivalent duration in storage.

A much larger flexible asset (in this case, a V2G fleet) was required to deliver the duration of storage required to achieve network benefit. Network savings are sufficient to justify a large V2G deployment of over 7M passenger cars (~20% of the fleet). But only edge technologies such as V2G can deliver the full network benefit. Grid storage located at higher levels in the system cannot address issues on the distribution network.

4.3. Competition amongst flexibility solutions creates path dependencies

All flexible assets can reduce the discrepancy between supply and demand. However, as more flexibility is deployed, supply/demand imbalance is reduced which can reduce the value of subsequent flexibility capacity. The reducing marginal value creates the potential for increased competition between these assets. This means that technologies which become established early may dominate the market, making it harder for others to become established.

Where those later technologies offer distinctive benefits, path dependences established now may prevent the system accessing those benefits in the future. For example, if utility-scale storage comes to dominate the market, this may make it more difficult for the distribution network to access the benefits of V2G for smoothing the load profile on the LV network. That might in turn increase the overall amount of network investment that is needed to hit 2050 targets.

4.4. Distributed storage may struggle until network value streams are developed

The market currently favours centralised storage over distributed because ESO and energy trading value streams are well developed while DSO value streams are still nascent. Coupled with the fact that the energy system is more accustomed to exploiting the scale economies of a small number of large assets rather than the standardisation economies offered by large numbers of small assets, this creates a significant barrier to distributed storage. This in turn means that there is significant risk that utility-scale storage will dominate the market, stifling optimal deployment of distributed storage.   As well as the economic consequences of converging on a non-optimal solution, this may have social consequences – distributed assets engage consumers and citizens directly, in a way that centralised ones don’t, and so support greater engagement in the energy transition.

4.5. The trade-off between risks of asset stranding versus flexibility solutions needs to be reviewed

Centralised storage and traditional network reinforcement are also favoured by another dynamic: the imbalanced trade-off between the risk of asset stranding versus that of using novel flexibility solutions.

DSOs are accountable for delivering both network capacity and reliability of power supplies. Traditional network investment gives assured capacity at known levels of reliability but carries significant risk of asset stranding if expected load growth does not materialise. Flexibility solutions offer capacity and reliability at lower levels of investment and lower risk of stranding, but their operational characteristics and reliability are less well known (and much less familiar to network engineers) creating significant novelty risk. Centralised storage has characteristics of both traditional solutions and flexibility, but it sits closer to the traditional end of the spectrum – it requires substantial upfront investment in return for relatively well understood performance characteristics.

However, much of the asset stranding risk can be socialised through the regulatory process. Once an investment programme is agreed, then the cost of any stranded assets will be borne by consumers. The consequences of any failure in flexibility services will continue to be borne by the DSO. This imbalance will tend to mean that DSOs favour traditional, centralised solutions over novel, distributed ones. Managing this imbalance will be critical to achieving a net-zero system in the most economical way.

It is also worth noting that passing the cost of stranded assets through to consumers creates a further risk, that of consumer defection. If stranded assets lead to a significant increase in network charges, then the likelihood of consumers going off-grid will also increase. This can then create a “death spiral”: network costs are spread across a smaller consumer base, further raising charges and prompting further defections. This is a small risk now, but as storage and V2G (or V2Home) technologies become more competitive, there will also be more scope for consumers to defect. Enabling consumers to capture value by providing flexibility to the grid would pre-empt this spiral.

5. Implications for stakeholders

Network companies

- We estimate that a passive system would require 30GW of network expansion by 2050. This could be reduced to 15GW by deploying flexibility. And reduced further to 10GW with the successful and widespread deployment of V2G. This demonstrates that a coordinated approach of flexibility with network expansion is required.

- Furthermore, flexibility allows network companies to run their assets at a higher load factor and generate greater revenues per unit of capacity.

- Network companies must currently choose between two risks – undertake traditional reinforcement and face the risk of stranding assets or use novel flexibility solutions and face the risk of unknown levels of service reliability. However, there is an inherent conservatism within current network design codes that could be leveraged to offset the risk of choosing the flexibility pathway.

- Flexible edge-technologies such as distributed storage provide distinctive benefits for the network. However, it may be difficult for them to become established in the market if they are not treated similarly to traditional reinforcement and centralised storage. Thus it is in the interests of network companies and end users to develop this asset class as quickly as possible, otherwise path dependencies may develop and lead to sub-optimal investment decisions.

Policy makers

- System flexibility arising from smart electrification of demand can reduce annual electricity costs by £4.5bn, a ~10% reduction. The system benefits of smart flexible demands would increase with greater electrification of demand e.g. lower deployment of hybrid heat pumps, and greater deployment of variable renewable energy sources.

- Most of the system savings from flexibility relate to avoided capacity investments and it may be challenging to monetise these savings (e.g. in network-charging models). Capacity is often required at times of peak system stress, and the maturity and reliability of DSR and other edge-flexibility solutions will need to be proven so that it becomes a viable alternative to traditional capacity investments.

- It is vital to deploy and prove DSR at scale now so that it can become a viable alternative to traditional investments. The risk/reward profile of asset classes differs. Traditional assets have well understood characteristics and low operational risk (but higher risk of stranding). Flexibility is less well understood and so has higher operational risk (but lower stranding risk). In the current regulatory model, the distribution network operator (DNO) carries the operational risk while the stranding risk is essentially socialised. To achieve optimum deployment of flexibility, we need to either adjust this risk model or allow DNOs to earn greater returns on flexibility to compensate for the greater risk they are taking.

- The marginal value of flexibility and storage assets are reduced with increased deployment. The erosion of revenues and competition between technologies could disincentive necessary investment. However, there is a link between deployment of VRES and flexibility - increased VRES deployment helps to maintain grid conditions that support flexibility, and flexible technologies help to improve the economics of VRES deployment. Decarbonisation policy should recognise the benefit of parallel deployment and incentivisation of system flexibility and VRES.

- The declining marginal value of flexibility and storage assets means that technologies that become established early may lock others out of the market. Markets accessible to grid-scale storage are currently well developed while those for distributed storage are not – this may mean that the market converges on a sub-optimal mix of grid-scale and distributed storage.

Flexibility providers

- There is a large and growing need for flexibility services across all scales of the energy system. However, the analysis shows that different sources of flexibility can overlap in their services to the system, resulting in competition between technologies and potential cannibalisation of market share.

- To ensure flexibility is able to deliver whole-system value - by avoiding investment in traditional technologies for capacity - flexibility technology developers need to move quickly to deploy and prove their technology at scale.

- Flexibility technology developers should recognise the benefits of decarbonising via VRES, which expands the market need for flexibility (compared to nuclear). By linking the growth of flexibility to deployment of VRES, providers can show how their technology is vital, not only for reducing system costs but also for decarbonising the power system.

Appendix A: Integrated Supply+Demand Model

Integrated Supply Demand Model (ISDM) is a proprietary energy model developed and maintained by Element Energy. It was originally developed to determine the optimised configuration and operation of power systems to ensure the security of supply with very high penetration of renewable energy sources.

ISDM was developed to represent multi-vector low or zero carbon energy systems with high penetration of VRES. By placing equal emphasis on demand side and flexible system technologies as it does the supply side and so overcomes many limitations of traditional power dispatch models. The starting point for the modelling used is the set of hourly energy demand profiles. The model is populated with a detailed breakdown of the demand by end-use types. The demand is differentiated based on its hourly profile and potential for flexibility.

For heating, these demands are based on the building sector heat loss, heating technology and outside air temperatures. Weather data is taken from a 1-in-20 year cold period, but an alternative can be used. Some demand profiles are fixed (no flexibility), while others are able to be shifted over defined periods. Country-specific hourly weather data is also used to generate hourly load factors for wind and solar production.

An initial specification of the VRES generation fleet is used and combined with the demand data to generate initial net-load curves. In normal operation, demand shifting is deployed to minimise net demand and, therefore, minimise generation curtailment. Network capacity is adjusted to optimise between demand driven and network curtailment. Alternatively, the fleet can be dispatched to minimise network loads. The dispatchable generation fleet is then deployed in merit order to fill in the supply gap. Remaining unmet demand is supplied by seasonal storage, and generation capacities are updated to reflect this. Once all hourly demand is met, annual system performance metrics are evaluated (CO2, limits on biomass use) and generation inputs adjusted to meet targets. Final outputs are generator capacities, network capacities, electrolyser capacities, storage, and H2GT capacities, and associated costs.

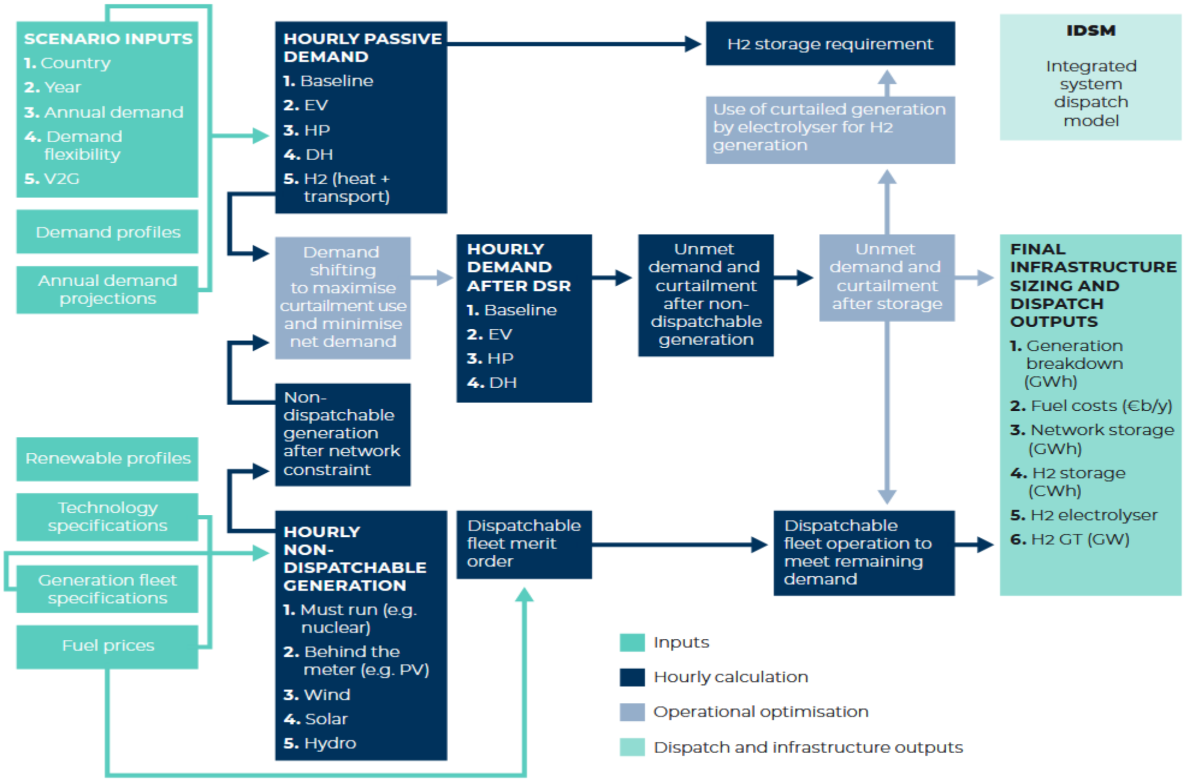

Figure 15: Integrated System Demand Model - primary modules

Credits

Element Energy

Element Energy is a dynamic and growing strategic energy consultancy. They specialise in the intelligent analysis of measures that can reduce carbon emissions in the built environment, energy and transport sectors. Since forming 18 years ago, they have grown to over 80 personnel and have become one of the largest low carbon-focused consultancies in the country.

Graham Oakes

Graham Oakes helps municipal, local and community energy systems identify and exploit the value of flexibility for the energy system. He founded Upside Energy in 2013, steering it to raise significant grant and equity funding and so develop an advanced flexibility platform. Since stepping down from Upside in early 2018, he has supported a number of projects across the UK and EU to develop flexibility-enabled products and services, and worked with regulators and policy makers to develop an environment where such products can succeed in the market.

Piclo

Piclo has been at the forefront of innovation in the fast-changing energy industry since 2013. Previously trading as Open Utility, Piclo's mission is to power the world with cheap, clean and abundant electricity. Piclo runs Piclo Flex, the UK's leading independent flexibility marketplace. Read more about Piclo's story.

Innovate UK

Innovate UK is part of UK Research and Innovation, a non-departmental public body funded by a grant-in-aid from the UK government.

They drive productivity and economic growth by supporting businesses to develop and realise the potential of new ideas, including those from the UK's world-class research base.

Project LEO

Project Local Energy Oxfordshire (LEO) is one of the most ambitious, wide-ranging, innovative, and holistic smart grid trials ever conducted in the UK. LEO will improve our understanding of how opportunities can be maximised and unlocked from the transition to a smarter, flexible electricity system and how households, businesses and communities can realise its benefits.

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Published in the UK: April 2020

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