Energy Research Partnership report

Delivering flexibility options for the energy system: priorities for innovation

May 2012

The Energy Research Partnership

The Energy Research Partnership is a high-level forum bringing together key stakeholders and funders of energy research, development, demonstration and deployment in Government, industry and academia, plus other interested bodies, to identify and work together towards shared goals.

The Partnership has been designed to give strategic direction to UK energy innovation, seeking to influence the development of new technologies and enabling timely, focussed investments to be made. It does this by (i) influencing members in their respective individual roles and capacities and (II) communicating views more widely to other stakeholders and decision makers as appropriate. ERP's remit covers the whole energy system, including supply (nuclear, fossil fuels, renewables), infrastructure, and the demand side (built environment, energy efficiency, transport).

ERP is co-chaired by Professor David Mackay, Chief Scientific Advisor at the Department of Energy and Climate Change and Nick Winser, Executive Director at National Grid. A small in-house team provides independent and rigorous analysis to underpin ERP's work. ERP is supported through members' contributions.

ERP Membership

This report has been prepared by Jonathan Radcliffe, with input from ERP members and their organisations. The views are not the official point of view of any of these organisations or individuals and do not constitute government policy.

Contact: Jonathan Radcliffe (ERP Analysis Team) jonathan.radcliffe@energyresearchpartnership.org.uk.

Contents

Summary ... 4
1. Introduction and background ... 6
2. Delivering technology options for flexibility ... 8
   2.1. Demand side response ... 8
   2.2. Interconnection ... 10
   2.3. Bulk storage ... 11
   2.4. Flexible generation ... 13
3. Implications for energy systems analysis ... 14
4. Conclusions ... 16

Summary

To meet carbon emission targets, the UK's energy system in the 2020s is likely to have high levels of intermittent generation from wind power, with increasing electrification of heat and transport. However, we need a better understanding of how intermittency can be managed to ensure an efficient transition to a low-carbon economy. A number of options could provide operational flexibility on such a radically different system, including more electrical interconnection, demand side participation, energy storage and flexible thermal generation. Some directed innovation programmes in these areas would develop the technologies and assess their full potential, helping to guide further investments and design appropriate policy instruments and a regulatory framework.

The Renewable Energy Review by the Committee on Climate Change set out an ambitious scenario for managing intermittency, at relatively low cost, in a system with more than 50% of generation from renewables. To achieve this would require significant innovation in some technologies, and unprecedented changes to system operation as patterns of supply and demand shift. The scale of meeting the challenges of intermittency should not be underestimated, but nor should it be a barrier to the deployment of renewables. Many of these issues will be played-out as the proportion of wind generation rises towards 30% of total capacity in the 2020s, and the preparations should be put in place now.

In this report, we use the assumptions and results from the CCC's scenario as a starting point for studying how technologies could help manage intermittency. We propose priorities areas in which innovation could reduce the impacts of intermittent generation and improve the flexibility of the energy system. Our analysis draws on the previous work by the Energy Research Partnership and experience of its Members to consider technical and engineering challenges, the business cases for technology deployment, and how further analysis of the energy system should incorporate a wider set of perspectives. The key findings are:

Technical and engineering challenges

Technological options could provide greater system flexibility, but need further development to show their potential scale and performance. Priorities for innovation are to:

- demonstrate how effectively thermal storage can manage power requirements for heat pumps, particularly in commercial buildings, and retrofitted in domestic properties;
- develop lower cost vehicle-to-grid capability in networks and vehicles;
- ensure smart meter systems are deployed which will enable demand-side participation;
- consider how to integrate interconnection of the GB electricity network with offshore wind development, and support the commercial development of some key enabling technologies;
- support research, development and demonstration of energy storage technologies, including novel thermal storage;
- improve the efficiency and reliability of thermal generation which will be responding to rapid changes in demand.

Business cases and market framework

The market and regulatory framework, as it evolves under the EMR process, should recognise the current uncertainty in how flexibility will be provided from the possible options:

- Thermal plant, which Government expects to provide the flexibility through to 2030, will have significantly lower load factors than today, with potential over-generation at times of low demand. Such a situation would undermine investment in new plant under current market conditions
- If vehicle-to-grid and interconnection are required at the scale suggested by the CCC's scenarios, their low utilisation would need strong financial incentives for a business case to be made. Further analysis is required, and may show that other scenarios offer a more commercially viable development of the energy system.
- Flexibility from demand side participation and storage could be effective, but will need a value proposition to bring forward technologies and be taken up by consumers.

<u>Systems analysis</u>

The scale and nature of flexibility that is required will depend on the degree of intermittency and electrification of the energy system. The modelling for the CCC has up to 15% of demand as responsive. Any further scenario or modelling analysis on this topic should assess how sensitive results are to such high levels, in particular: the penetration of electric vehicles and heat pumps on the demand side, and the deployment of wind generation on the supply side.

Some technology-specific analysis would also help improve our understanding, including:

- the role of rechargeable energy storage – how, at what scale, and where, electrical and thermal storage can deliver most benefit to the energy system under different scenarios;
- the extent to which interconnection can provide flexibility to the UK electricity network, especially in periods of widespread low-wind events.

The CCC's scenario relies heavily on imported electricity during extended periods of low wind. We feel that security of supply considerations would favour more conservative levels of imports in periods when wind power could drop across Europe, especially given the uncertainty in generation mix elsewhere.

Flexibility options have been, and are being, considered independently, but their combined integration over the next 10 – 15 years within a dynamic energy system is a critical area in which understanding needs to be improved. Analysis should go beyond single point optimisation of the power sector and consider how other technology choices in buildings and transport could contribute to overall system flexibility. The CCC's work has been a welcome start, but needs to be built on, incorporating engineering, operational, business, regulatory and political perspectives in order to construct more credible future scenarios.

Renewable power generation will be critical to achieving carbon reduction targets. However, the extent to which thermal generation and other technologies will be required to manage the future energy system needs to be better understood. This will allow investment in infrastructure and innovation to be well directed, and for the market framework to be designed such that the system is delivered efficiently. Not investing now risks forcing the UK down high carbon pathways in the future, and missing opportunities for technology development.

1. Introduction and background

Renewable energy, in particular from wind, will play an important role in meeting the UK's carbon emissions reduction targets. To meet the UK's 15% renewable energy target by 2020, the Government has estimated that 30% of electricity generation will be required from renewables, with 15GW generation capacity from onshore wind and 13GW from offshore wind.[1] If this is achieved, the proportion of wind will exceed 20% of the electricity system capacity and delivered energy. To meet targets under the Fourth Carbon Budget[2], the amount of intermittent generation will be rising towards, and perhaps beyond, 30% over the subsequent decade[3].

Understanding how to manage such significant levels of intermittent generation is essential to ensuring we have a reliable and efficient energy system in place. The Government's Carbon Plan envisages that "Over the next two decades, gas-fired power plant will provide the flexibility that we will need to meet peak demand and manage intermittent generation from some renewables, as well as baseload generation capacity, while new nuclear and renewable capacity is built." [4] However, there could well be opportunities for new technologies to help manage intermittency, and to lower system costs, in the period to 2030 if innovation is encouraged.

The Committee on Climate Change (CCC), with Pöyry, has studied the impacts of high penetration of renewables in the UK, and how a full range of options could manage the system. Their analysis considers scenarios with 50% and 65% generation from renewable sources in 2030, though this level is above that which would be expected to meet carbon reduction targets. Even with penetration of 65%, the CCC concludes that "A range of options exist to address intermittency (demand-side response, interconnection, balancing generation) at a cost that is likely to be low relative to the costs of generation even up to very high penetrations." Placing such a low cost on intermittency can give the impression that the solutions will be easily achievable.

We find, though, that managing intermittency in the way described by the CCC for the UK relies on a series of ambitious assumptions being met. To deliver the options will require significant technological development, changes to system operation and greater participation from consumers. The scale of meeting these challenges should not be underestimated.

A recent report by the European Climate Foundation has also examined a scenario with high penetration of renewables - 50% across Europe[5]. Whilst the report found that current plans would be adequate to reach 2020 targets, key challenges for 2030 would be upgrading the grid infrastructure, investment in a diverse set of renewable technologies, and implementing demand side measures.

In the Annex we set out how each of the options for flexibility is used in the CCC's modelling, drawing on their review, and the accompanying supporting research from Pöyry. Whilst the numbers add up for such a modelled system, the technical, engineering and operational issues need to be fully explored to give confidence in achieving the proposed scenarios. A better understanding of future system and technology performance will help guide investment in infrastructure and the

---

[1] DECC (2010) National Renewable Energy Action Plan for the United Kingdom http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/uk_action_plan/uk_action_plan.aspx
[2] See http://www.decc.gov.uk/en/content/cms/emissions/carbon_budgets/carbon_budgets.aspx
[3] National Grid (2011) UK Future Energy Scenarios http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/
[4] See http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx
[5] ECF (2011) Power Perspectives 2030 http://www.roadmap2050.eu/pp2030

RD&D that can deliver the flexibility options most cost-effectively. Without such preparation risks higher cost, or more carbon intensive, pathways being taken, and missing opportunities for technology development.

We use the CCC's scenario of 50% renewables in 2030 as a starting point for a review of the flexibility options. Though such a high penetration of wind is beyond the current ambition for 2030, the issues will be pertinent as generation from renewables increases above 20%. This report covers:

- In section 1: the challenges of delivering each of the flexibility options if they are to be delivered at scale. The individual technologies may have a strong potential role to play in principle, but will require a focused innovation programme to bring them to commercial deployment.
- In section 2: how the energy system, and its operation, has been described by scenarios. Whilst scenarios and models can provide valuable insights, their outputs need careful interpretation and are dependent upon inputs and assumptions.

We make a number of recommendations, in bold text below, to guide support for innovation and on the treatment of assumptions in the analysis of the energy system, when considering the integration of intermittent generation.

2. Delivering technology options for flexibility

The technology options available to manage intermittent generation and increasing electrification of heat and transport are: interconnection of electricity systems, demand-side response, energy storage and generation from dispatchable plant. The scale of these options incorporated in the CCC's scenario for 2030, with 50% renewable generation, is summarised in the table, and described in more detail in the Annex.

Scenario	Demand	409TWh/yr	including 120TWh for heat & transport; current demand:350TWh
Scenario	Generation	125GW	total capacity, with 59GW onshore + offshore wind, 19GW nuclear.
Flexibility options	Demand side response	~20GW	moveable demand (15% of total) predominantly intra-day thermal storage for heating + inter-day EV storage
Flexibility options	Interconnection	16GW	- an increase on 4GW at present: 6GW with Norway, 8GW with North West Europe, 2GW with Ireland
Flexibility options	Bulk storage	4GW	with further pumped hydro storage increasing the current 2.7GW capacity
Flexibility options	Balancing generation	30GW 4GW	CCGT running at load factor 0.19 Coal CCS running at load factor 0.63

Table1: Scale of flexibility options from CCC's Renewable Energy Review scenario with 50% renewable generation.

The assumptions and innovation challenges for each of these are considered below.

2.1. Demand side response

The electrification of heat and transport will allow demand side response to have more of an impact on balancing the electricity system than at present.[6] There are currently few opportunities for consumers to offer dynamic services to the network, mostly limited to major industrial and commercial users with interruptible contracts. In the domestic sector, 23% of electricity consumption is associated with time-of-use tariffs (such as Economy 7), with electrical heating as the primary system in 7% of UK housing stock. There is little consensus over the amount of further moveable demand, though DECC's impact assessment of a GB-wide smart meter roll out for the domestic sector assumes a 5% load shift from a 20% uptake of time-of-use tariffs.

The CCC scenario has 15% of electrical demand as responsive in 2030, primarily from heat (using thermal storage) and transport (with EV charging and Vehicle-to-Grid). Unlocking such a magnitude will need development and demonstration of the individual technologies (not least to better understand consumer behaviour) and deployment of appropriate ICT systems and infrastructure.

A critical aspect for any demand-side technology will be valuing the flexibility of energy use, so they are commercialised and taken-up by consumers. As was found in a recent workshop, without a route to capture the value from demand-side response, this option will not deliver.[7] The role demand-side response can play needs further analysis and to be recognised by the Electricity Market Reform process.

---

[6] See ERP (2011) The future role for energy storage in the UK, p.16, for the potential of demand side response.

[7] UKERC (2011) The Role of Demand Side Participation in Managing Generation Intermittency. Workshop Report http://www.ukerc.ac.uk/support/tiki-index.php?page_ref_id=3020

Heat

The electrification of heat is seen as an important step to decarbonising energy demand in the UK. The CCC's scenario for meeting 2030 targets set out in their Fourth Carbon Budget report has 143TWh of heat delivered from heat pumps (HPs) in 2030, a quarter of total heat demand. Of this, 37TWh is provided from thermal storage associated with HPs, predominantly from the non-domestic sector. In the domestic sector, the CCC expects 25% of households to have HPs by 2030, of which 25% will have thermal storage attached.

Though thermal storage in principle is a straightforward technology when hot water is the medium, such systems linked to HPs have not been widely demonstrated in the UK. Even HPs themselves are in the early stages of field trials in UK housing stock. Shifting demand for heat to night-time storage when temperatures are lowest would have an adverse impact on the coefficient of performance of HPs. In the worst case, under severe conditions, heat pumps could revert to operation as direct acting immersion heaters. Measuring the extent to which this increases electrical demand, and the impact on networks (especially at the distribution level) is an example of the extra data required.

Having the space available for thermal storage is non-trivial – a report for the CCC envisages 2500l of stored hot water for domestic systems. The opportunity costs of this loss of space should be taken into account in the analysis. For commercial buildings, space is perhaps even more valuable than in the domestic sector and may affect the feasibility of deploying thermal storage. In houses, conventional hot water cylinders are being quickly replaced by combi-boilers, and affect future deployment of thermal storage. New phase change materials (PCMs) offer the prospect of reduced size of thermal stores, but are still at the development stage.

Upcoming trials will study the effects of thermal storage with heat pumps in the domestic sector and provide valuable evidence for future analysis. However, trials to assess performance and suitability should also be conducted in the non-domestic sector, where the CCC finds significantly more potential.

The full costs of installing thermal storage should be studied and taken into account. Results may show the benefits of using lower volume phase-change materials in place of hot water, and guide RD&D funding.

Transport

If the take-up of EVs is at the rate necessary to reach the CCC's 2030 targets (with 11 million EV/PHEVs on the road) 'smart' charging will bring great opportunity to shift demand across hours and possibly even a day or two.

In the CCC's scenario, vehicle-to-grid (V2G) provides up to 10GW at peak times, with 50GWh delivered over 7 hours, during periods of low wind. Whilst this appears achievable in principle, the role for V2G is very uncertain, given questions over battery lifetime from increased cycling and whether consumers would be wiling to provide such a service back to the network. It also requires that charging points and vehicles be designed to be compatible with V2G, and that distribution networks are able to handle such power flows.

Further, the business case for providing any additional equipment or services to enable V2G is questionable if the system demand for it is limited (as is the case in the CCC scenario). Recent research by Ricardo and National Grid has shown that capital costs would make V2G for balancing uneconomic in a 2020 scenario.[8] The CCC's analysis does not appear to include additional costs of V2G equipment or infrastructure.

Further analysis should be undertaken to show if V2G has a bigger role to play in managing intermittency in scenarios where other technologies do not deliver, and therefore whether it is a valuable option to retain. In this case, a concerted innovation programme to develop technologies, reduce costs and define standards should be considered.

Smart meters

Both EV/V2G and thermal storage options will need appropriate control functionality to provide flexibility for the energy system. The roll-out of smart meters from 2014 should allow this, though some recent reports have highlighted where better understanding and further development is needed. To support this, Government will be undertaking work during 2012 on various technical aspects of smart meters, including trials of Home Area Network.

However, a UKERC workshop on 'Future requirements for smart metering' found that current research does not adequately consider the place of smart meters within the wider energy system.[9] And a report by the Public Accounts Committee on 'Preparations for the roll-out of smart meters' concluded that "There is a risk that the smart metering system may not be able to support the development of smart grids, designed to better match electricity supply and demand, without incurring additional expenditure to modify or upgrade the meters and the data communications system."[10]

In setting out the technical specification for smart meters, it is critical that a system is developed to allow the electricity network to operate with demand side participation as it could look under scenarios with greater electrification of heating and transport.

2.2. Interconnection

Interconnecting electricity transmission networks gives an opportunity for balancing electricity systems geographically, rather than the temporal flexibility of demand side response or storage. The GB network is currently linked to the 'Republic of Ireland and Northern Ireland Single Electricity Market' (SEM), and North West Europe (NWE), with total 3.2GW capacity. There are proposals for further such links, and also to Norway, which could give access to hydro generation and Pumped Hydro Storage (PHS).

The CCC's scenario has 16GW interconnection capacity in 2030, showing transmission links already proposed for an extra 5GW. National Grid forecasts an extra 2.5GW by 2020, with total 7.6GW in their Gone Green scenario by 2030.[11] Increasing the current interconnection capacity would undoubtedly benefit GB system flexibility, especially with wind output fluctuating over periods of

---

[8] http://www.ricardo.com/en-GB/News--Media/Press-releases/News-releases1/2011/Report-shows-how-future-electric-vehicles-can-make-money-from-the-power-grid/

[9] UKERC (2011) 'Future Research Requirements for Smart Metering Workshop' report http://www.ukerc.ac.uk/support/tiki-read_article.php?articleId=1381

[10] House of Commons Public Accounts Committee (2012) Preparations for the roll-out of smart meters http://www.publications.parliament.uk/pa/cm201012/cmselect/cmpubacc/1617/161702.htm

[11] National Grid (2011) Gone Green 2011 http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/; Government estimates 2-3GW of interconnection will be built by 2020, see DECC (2011) Statutory Security of Supply Report http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/energy-security/3425-statutory-security-of-supply-report-2011.pdf

hours. However, the stronger links between markets would also add complexity to system operation.[12] Further, the impact of such interconnection on the provision of a secure UK supply during a wind-lull across northern Europe is a serious matter, and described further in section 2 of this paper.

Whilst point-to-point interconnection itself is a mature technology, the scale and design of its deployment (in conjunction with offshore wind farms) may raise some engineering challenges. If these can be addressed, there will need to be an appropriate market framework in place which signals to business that building such levels of interconnection will be commercially viable.

Delivering a four-fold increase in interconnection by 2030 would need a market framework that valued such a capacity. The CCC and Pöyry reports do not give details of the overall utilisation of the cables, but from the case study that has been published, it appears that the load factor drops considerably for the capacity above 7GW. This would make a business case for building the additional 9GW a challenging proposition without other incentives.

Analysis of the load-duration curves for interconnectors between GB and each of SEM, NEW and Norway would help inform thinking on the priorities for new cables.

Designing interconnected systems

Consideration of such high level of imports should come from a more strategic view of interconnection across Europe. This may lead to a conclusion that a North Sea grid should be pursued which will need technological development, a new market framework and political agreement. We have separately reported conclusions from a UK-Norway workshop to look at the potential from North Sea Offshore Networks[13], and recognise the work by DECC and Ofgem investigating the options through the North Sea Countries Offshore Grid Initiative (NSCOGI).

Though PHS in Norway is often seen as a providing the 'green battery' for Europe, there are still major environmental, economic and engineering issues to be resolved. We should not take PHS in Norway as a given.[14]

Developing proposals for the strategic use of the North Sea as a hub for wind power and transmission networks should be a priority for Government, regulators, academia and industry, working with other European countries. Technical, political and market challenges will need to be addressed for this to be a possibility.

2.3. Bulk storage

Conceptually, storing electrical energy at times of over-supply for later use is an ideal solution for a system with more electrified energy demand and variable renewable generation. The role for energy storage, though, is poorly described in many pathways to a low-carbon economy because models have difficulty capturing its full benefit.[15] Such technologies can operate over timescales shorter

[12] See National Grid (2011) Operating the Electricity Networks in 2020 – Update June 2011, section 10 http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/
[13] UKERC/ERP/Sintef (2011) North Sea Offshore Networks, UK-Norway Forum and Workshop http://www.energyresearchpartnership.org.uk/offshorenetworks
[14] See, for example, SEFEP (2012) Norway and the North Sea Grid http://www.sefep.eu/activities/publications-1/norway-and-the-north-sea-grid/
[15] ERP (2011) The future role for energy storage in the UK http://www.energyresearchpartnership.org.uk/energystorage

than the temporal resolution of the model, be sensitive to scale and location of their deployment, with future performance and costs not well defined.

Currently, pumped hydro storage (PHS) in the UK has 2.8GW generating capacity, with up to 28GWh stored energy, from four major sites (Figure 1). The characteristics of each site are important: Dinorwig in Snowdonia has a low volume of stored water compared to the two major PHS sites in Scotland, but is able to generate 1.7GW from a high head. Given the geography of the UK, future PHS is unlikely to deliver such high power output, but could store significant energy volumes. In Scotland, SSE is proposing to build the UK's first new PHS facility in 20 years, which would double the storage volume (with up to 30GWh) generating a maximum 0.6GW power output.

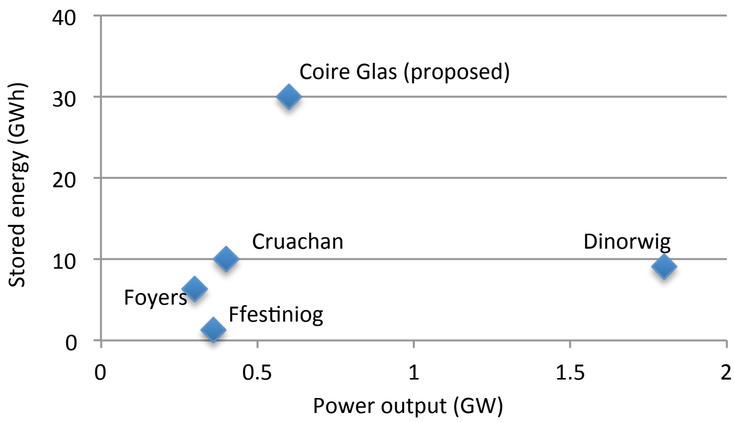

Figure 1 Current and proposed pumped hydro storage in the UK[16,17]

In the CCC's scenario, bulk electrical storage connected to the transmission network increases to 4GW capacity, with characteristics analogous to Dinorwig (though there is an anomalous reduction in storage volume to 20GWh). Despite this, energy storage appears to play a very limited role in providing power at peak times.

The potential from energy storage could be game-changing, and the possible developments should be included in the same way as advances in other technologies. For example, in a 2030 scenario in which 11 million cars have some storage capacity, it might be reasonable to expect that electrical storage devices of with 10 – 100 kWh will be a relatively mature technology. To show the scale of the potential storage, if 20kWh of battery storage were placed in a million homes, there would be 20GWh of energy volume and 3GW power available. Therefore such batteries may also have a role as affordable distributed electrical storage.

Following recent reports on energy storage from ERP and others, several studies have been, or are in the process of being, funded to improve understanding of the role and value of energy storage in the UK's energy system. These will need reinforcing and developing to provide robust evidence, but should give an indication of the storage characteristics that will be most valued.

[16] MacKay (2009) Sustainable Energy – without the hot air http://www.inference.phy.cam.ac.uk/withouthotair/c26/page_191.shtml
[17] SSE (2012) Press release: http://www.sse.com/PressReleases2012/CoireGlasPlanningApplication/

To back-up analysis of the role of energy storage, demonstration of specific technologies will be required to show how they can perform in an energy system, and how system operators and consumers utilise them.

Such activities are being considered by DECC, and are within the scope of Ofgem's low carbon innovation stimulus, so these organisations should work closely together and with others to maximise learning. ERP is taking a leading role to foster coordination in energy storage innovation.

2.4. Flexible generation

The default assumption for providing flexibility in support of intermittent generation is to use fossil-fired power stations, with relatively low (or sunk) capital costs, and only operating (hence emitting carbon) at times of peak demand or low renewable supply. The contributions from interconnection, demand-side response and storage will determine the amount of plant required and how often it has to operate. Under the CCC's scenario for 2030, just the 30GW CCGT plant that is already built or planned is called on, running at an average load factor of less than 20%. In 2010, 75% of CCGT ran at more than 60% load factor.[18]

Overestimating the potential from the technologies considered in the sections above may lead to an underestimation of the conventional thermal generation required to balance the electricity system. There are risks both of too great an investment in new plant (which would be inefficient) and too little (which would lead to a loss of energy security). In either case, and under any scenario with generation from wind increasing, overall load factors of conventional thermal generation will drop significantly from the current level. There will also be times when *over*generation will need to be managed, particularly at times when the wind is strong but demand is low (in the summer). Yet the load-following ability of gas-powered generation will be valuable.

A market framework will need to be in place that sufficiently values the availability of capacity with low load factors to ensure secure electricity supplies. This becomes more complicated if and when carbon capture and sequestration is being commercially deployed - potentially in the late 2020s - following development of the technology by public and private sectors, and an expectation that returns will cover the significant investment costs.

Low load factors may also bring technical challenges to improve efficiency and reliability of plant that is rapidly and frequently ramping up and down. As well as for fossil fuel-fired generation, there would be benefit from more flexible nuclear energy.

The economic and technical consequences of conventional generation running at low load factors, and operating more responsively to changes in other supply and demand, need to be fully assessed. This should inform Electricity Market Reform, the design of new power stations, and priorities for energy innovation programmes.

[18] National Grid (2011) Development of Energy Scenarios http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/47855/DevelopmentofEnergyScenariosTBE2011.pdf

3. Implications for energy systems analysis

Impact on security of supply

An energy system with intermittent wind generation and high demand for electricity should be in a position to withstand weather-related 'shocks' to a given level. Such a shock could be that of a blocking anticyclone that draws cold arctic air over Europe, reducing supply and increasing demand. Providing the GB system with imported electricity in this case would require generation capacity being available in the SEM, NWE or Norway, which may also be experiencing the same impact on wind generation.

Assessing the extent and frequency of wind lulls, the consequent impact on wind generation in the UK and continental Europe, and the resulting effect on European power flows, is clearly complex. Not only is there uncertainty over the UK's energy mix to consider, but that of several other key European countries whose electricity system are undergoing similar transitions – intermittent generation could be more than 20% of the EU's total capacity by 2030. Rigorous analysis will be required to show the back-up generation plant required for such an event, and may include amounts of natural gas storage available.

For the CCC's 50% renewables scenario, Pöyry modelled a winter wind lull case study. This had a period of low wind (<10% capacity) for three days, during which an average 8.5GW was imported (with total energy 600MWh), peaking at 15GW. The available evidence is not convincing that in this case there will be excess capacity in SEM or NWE to cover the shortfall in UK wind generation when it could be supplying domestic markets. Indeed, Pöyry's report for the CCC's Fourth Carbon Budget report correlated wind load factors in GB with NWE and found that interconnection "would only provide limited flexibility, and could even make things worse at times."[19]

We do not believe that significant levels of imported electricity to meet demand can be assumed in the event of multi-day wind lulls.

For DECC's 2050 Pathways, its scenarios are tested with a five-day period that has a drop in on- and off-shore wind output to 83% of mean annual output and average temperature of -1.4°C.[20] For the 'central electrification, nuclear' trajectory, which has 27.5GW wind, 4GW storage and 10GW interconnection, the pathway require 5GW gas-fired plant for back-up.

Future modelling of the GB system should consider cases with zero imports from SEM and NEW in low wind periods, with further analysis to assess the reliability of imported supplies. Recent changes to energy policy in other European countries have made the impact of widespread low wind even more acute. Improved assessment of the value of interconnection to the UK more broadly under European energy scenarios would help inform further analysis of managing intermittency.

System sensitivities

We have noted a number of areas where the level of technology deployment will have a strong impact on the system flexibility. The effect of different deployment levels needs better quantifying, as they can appear very ambitious relative to the current situation, and when there are multiple

[19] Pöyry (2010) Option for low-carbon power sector flexibility to 2050 http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research
[20] http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

pathways to meeting low-carbon targets. For example, the roll-out of electric vehicles could benefit system flexibility, but if another technology (such as hydrogen fuel-cells or biofuels) took the market lead, this would have knock-on implications for managing intermittency.

As these flexibility options reduce, conventional generation is likely to play a greater role. The subsequent impact on economic and carbon costs will be important results.

The period of 2020s will be a critical period for the managing the UK's energy system – there may be 30GW of wind capacity (predominantly offshore), but the flexibility options described above are unlikely to have been deployed at significant scale. In this case it is conceivable that CCGT plant will be built to maintain reliable supplies, providing back-up and flexibility. In the short term, through the 2020s, this could crowd-out the space for investment in other options, and in the longer term, emissions from CCGT (without CCS) will be too high for the UK power sector to meet 2050 targets.

We recommend more detailed analysis of the period between now and 2030, studying the system operation challenges which will arise as new supply and demand technologies are deployed, and therefore what a realistic amount of CCGT will be required in this intervening time.

Further sensitivity tests should examine economic and carbon costs for varying deployment levels of:

- **EVs, and their V2G capability;**
- **HPs with thermal storage, incorporating full cost estimates;**
- **Interconnection, including with zero or negative imports during trans-continental low wind events.**
- **Energy storage, taking into account likely characteristics of large-scale PHS and the potential for distributed storage, drawing on results from ongoing studies to assess the role and value of storage.**

As well as the high levels of renewables employed in the scenarios described in the CCC's report, the same system analysis should be given for renewable generation at levels which are described as currently appearing to be the most appropriate to meet carbon reduction targets (i.e. 40% of total generation).

4. Conclusions

Ensuring that £200bn is invested in the UK's energy infrastructure over the next decade in the most effective way is an important task. Undertaking technology demonstrations and rigorous systems analysis that could help integrate generation from intermittent sources will ensure the energy system is designed efficiently, minimising the risk of stranded assets or taking inadvertent high carbon pathway at a later date. It would also show opportunities for technological development that would place the UK in a good position to capture market share elsewhere, as intermittency becomes a systems issue in other countries deploying renewables.

We emphasised in our report 'Innovation Milestones to 2050' that the next decade would need substantial demonstration of technologies so that decisions which may affect the long term future of the energy system can be taken with the best available information.[21] We are pleased to see some demonstration activities getting underway in this area – ETI is investigating energy storage devices, Ofgem is funding projects through the LCIF, DECC plans to incorporate thermal storage in studies of heat pump use in UK housing stock, and there are various pilot EV schemes underway.

However, the scale of these activities needs to be increased and in some cases the nature of the trials needs to be refocused to produce outcomes that will help inform future decisions on the evolution of the energy system over the next 20 years.

A further step would be for the CCC scenarios/Pöyry models to be re-examined in the light of stakeholder input on the flexibility options. The issues raised in this paper should provide a starting point, and the Energy Research Partnership would be happy to guide further work

Costs

In this paper we have focused on the innovation requirements that appear to offer options for system flexibility under high levels of intermittency, and how the technologies are represented in the system by models.

The cost assumptions for providing the flexibility have not been treated here, other than to note where some costs do not appear to have been taken into account (such as providing V2G capability, or opportunity costs of providing space for thermal storage). That the costs of managing intermittency are found to be so low, relative to the cost of generation, can give the impression that the solutions are easily achievable.

We will look further at the treatment of costs by the CCC. However, a more general systematic and thorough examination of the costs of intermittency, as previously undertaken by the UK Energy Research Centre (2006)[22], in the context of a high deployment of renewables may be appropriate at this time, given the often polarising debate surrounding wind power.

[21] ERP (2010) Energy innovation milestones to 2050 http://www.energyresearchpartnership.org.uk/Milestones
[22] http://www.ukerc.ac.uk/support/Intermittency