Delivering flexibility options for the energy system, Technical Annex: Analysis of Committee on Climate Change 50% renewables scenario

May 2012

This Technical Annex accompanies ERP's report 'Delivering flexibility options for the energy system: priorities for innovation'. The main report uses the assumptions and results from scenarios of the Renewable Energy Review by the Committee on Climate Change as a starting point for studying how technologies could help manage intermittency.

The Committee on Climate Change concluded that in high renewables scenarios, managing intermittency from wind generation could be technically achievable at relatively low cost:

> *"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. For example, analysis that we present … suggests that even for renewable shares up to 65% in 2030 and 80% in 2050, the cost is only up to 1 p/kWh of additional intermittent generation."*

This paper examines the key points of the different flexibility options as used by the CCC, focusing on the scenario with 50% renewables in 2030. The inputs and assumptions used in the model are described, and the main uncertainties and barriers that would need to be overcome to meet this target are set out. A case study of how such a system responds to a two-week winter period with several days of low wind, which was modelled by Pöyry, is also considered.

Contents

Overview

The Committee on Climate Change's 'Renewable Energy Review'[1] (CCC RER) was commissioned by the Government to provide advice on the scope to increase ambition for energy from renewable sources. The Committee also wanted to establish if very high penetrations of renewables could in principle be managed and to establish the requirements and probable costs in doing so.

Following on from the CCC's Fourth Carbon Budget report (CCC 4CB)[2], the CCC RER presents a scenario in which renewable electrical generation reaches 230TWh (50% of the total generation) by 2030. This is higher than the 40% generation from renewables, which the CCC describes as currently appearing to be the most appropriate level to meet carbon reduction targets. The report notes:

- *This scenario constrains CCS investment, reflecting a world where CCS demonstration shows this technology to be either not technically feasible or not economically viable.*
- *Nuclear continues to be built at all currently approved sites and offshore wind investment in the 2020s roughly doubles compared to the 2010s.*
- *This scenario could be appropriate where renewables are cheaper than CCS and nuclear investment cannot be increased beyond current plans.*

Pöyry Management Consulting was commissioned by the CCC to examine the scope for maintaining security of supply, using their Zephyr model to undertake the analysis. [3, 4]

Balancing the electricity system in this '50% renewables' scenario relies on demand response and interconnection being deployed as flexibility options at significant scale. The nature and magnitude of the technology options are summarised in Table 1.

Scenario	Electricity demand	409TWh/yr	including 91TWh for heat, 30TWh for transport and 288TWh for lighting and appliances (demand in 2010: 328TWh)
	Generation	125GW	total installed capacity, including 19GW nuclear, 21GW onshore wind, 38GW offshore wind
Flexibility options	Demand response	~20GW	moveable demand (15% of total) predominantly intra-day thermal storage for heating + inter-day EV storage
	Interconnection	16GW	of which: 6GW with Norway, 8GW with North West Europe, 2GW with Ireland (current interconnection: 4GW)
	Bulk storage	4GW	new storage assumed to be pumped hydro an increase on 2.7GW pumped hydro storage at present
	Balancing generation	30GW 4GW	- CCGT running at load factor 0.19 - Coal CCS running at load factor 0.63

Table 1 Main elements of the CCC's 2030 50% renewables scenario.

[1] Committee on Climate Change (2011) Renewable Energy Review http://www.theccc.org.uk/reports/renewable-energy-review
[2] CCC (2010) The Fourth Carbon Budget http://www.theccc.org.uk/reports/fourth-carbon-budget
[3] Pöyry (2011) Analysing technical constraints on renewable generation to 2050 http://www.theccc.org.uk/reports/renewable-energy-review
[4] Zephyr is described as being based on a mixed integer linear programming platform, simulating the dispatch of each unit on the GB and Irish systems for each hour of every day. The optimisation finds the least cost solution taking into account the sum of variable costs (including fuel and carbon), the costs of starting plant and the costs of part-loading.

In sections A to D below, we outline the role of each of these flexibility options in the 50% scenario, highlighting key inputs and assumptions made, and point out key uncertainties which underlie the use of the flexibility options as described by the scenario. The sensitivity runs of the model are described in section E, and the interaction of the technologies is then described in a modelled case study in section F. This Annex concentrates on technical aspects of the flexibility options; the main report also considers how a business case is an integral part of deploying the technologies.

As part of their study for the CCC, Pöyry estimated the costs of resolving the potential technical constraints for the options (given in Annex A of their report and shown in relevant sections here). The CCC then calculated the total costs for system flexibility measures, details of which are given in the Technical Appendix to the Renewable Energy Review.[5] Given the annualised costs for system flexibility options, and shedding of low variable cost generation, the CCC generated an estimate of the total system costs for each additional kWh of intermittent generation. In general, the results suggested that the increased costs were of the order of 1 pence per additional kWh of intermittent renewable generation. Our analysis has not considered these cost estimates, though we recognise this as being an important future area for further work.

Key messages from ERP

Though the message from the CCC's Review is that managing intermittency in a scenario with 50% (and more) renewables can be achieved at low relative cost, it will have serious challenges for technology development, system operation and policy if the flexibility options are to be delivered.

The deployment of EVs (with vehicle-to-grid power transfer) and heat pumps (with thermal storage) at scales set out in CCC Fourth Carbon Budget report will require significant innovation to bring these technologies to market. Allowing the scale of imports will be an engineering challenge if extensive new build of interconnectors is to be integrated with offshore wind, and need much greater cable production volumes. Whilst the management of transmission and distribution networks will have to change under any low carbon future, the scenario envisaged by the CCC is very different from current system operation, and will also need radical behavioural changes from consumers.

Further, commercial deployment will rely on individual business cases being made for the technologies. The scenario reflects a low system cost, and understandably the report does not delve into whether there are viable value propositions for each technology. However, this will be a critical aspect for policy and regulation to address.

The main report looks in more detail at the innovation priorities to deliver flexibility options for the UK's energy system, particularly focusing on how to resolve the key uncertainties, and how the CCC's analysis could be extended to provide insights that would allow development of an operational system.

[5] CCC (2011) Renewable Energy Review - Technical Annex - Costs of low-carbon generation technologies http://www.theccc.org.uk/reports/renewable-energy-review/technical-annexes

A. Demand response

Extract from CCC Renewable Energy Review

"There is scope for significant demand response, with a particular opportunity from electric vehicle batteries:

- Pöyry's analysis suggests around 15% of demand could be flexible, at least within-day, in 2030.
- Just over half of the flexible demand is in heating, with the remainder primarily in the transport sector. This reflects our fourth budget assumption that electric car penetration has reached 60% of new cars by 2030, resulting in an electric vehicle fleet of around 11 million.
- Smart technologies and pricing that reflects electricity costs at time of use, and encourages consumer response, would be necessary in order to unlock this potential. Current Government proposals for smart meter roll-out have recognised this requirement."

Key points from scenario

- Annual 2030 demand is 411TWh, of which 346TWh is fixed, 65TWh (16%) is 'moveable' (Figure 1).

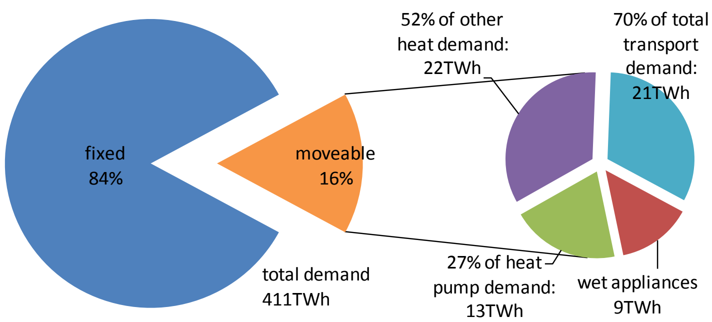

Figure 1 Moveable demand in the CCC's 50% renewables scenario.

- Transport provides multi-day flexibility and the ability to return to grid (vehicle-to-grid, V2G), heat and appliances provide within day flexibility to shift demand but not return to grid.
- Transport and residential non-heat demand are constant over the year at 65 and 20 GWh/day respectively. Moveable demand from heating is ~150GWh/day in the winter, dropping to ~40GWh/day in the summer.

Inputs/assumptions

- Heat and transport are electrified according to CCC 4CB scenario.
- Heat pumps (HPs) are deployed with storage and control systems.
- 1GW voluntary demand reduction in response to high electricity prices.
- Costs: £2.0bn/yr for smart meters/grids.

Key uncertainties

The scale of heat pump and electric vehicle take-up in the CCC 4CB is itself ambitious, but two aspects of their deployment are particularly relevant to the provision of flexibility:

- Deployment of heat pumps with thermal storage: The NERA-AEA report on low carbon heat for the CCC 4CB acknowledges these are not yet commercially available, though are a "plausible future development".[6] The report estimates that HPs with 2500l hot water storage tanks are suitable for 40 – 45% of all domestic properties, and about 55% of non-domestic properties. CCC 4CB assumes thermal storage in 25% of properties with HPs by 2030.

- Vehicle-to-grid: there are challenges to enabling this, especially concerning the vehicle/property charging hardware, supporting electricity distribution infrastructure, ICT systems and economic case.

Allied to these, there are uncertainties around:

- Deployment of smart meters, or other systems, with the technical capability to allow demand side participation. Meters may also have to be able to respond to dynamic pricing within a market framework which values flexible demand.
- Consumer response and behaviour to demand side participation.

B. Interconnection

Extract from CCC Renewable Energy Review

"Increased interconnection with European and Scandinavian systems offers scope for flexibility, given that load factors for renewable generation and storage technologies are likely to vary significantly across systems. Pöyry analysis suggests that interconnection could provide 16 GW of flexibility (i.e. 16 GW import capacity) by 2030; modelling for the European Climate Foundation considered up to 35 GW of interconnection to the UK by 2050."

Key points from scenario

- Interconnection capacity with Ireland's Single Electricity Market (SEM), North West Europe (NWE) and Norway is substantially increased by 2030 (Figure 2).
- Over a year, Pöyry modelling finds that GB is a small net importer in the 2030 scenario, with net imports from Norway of 7.5TWh.

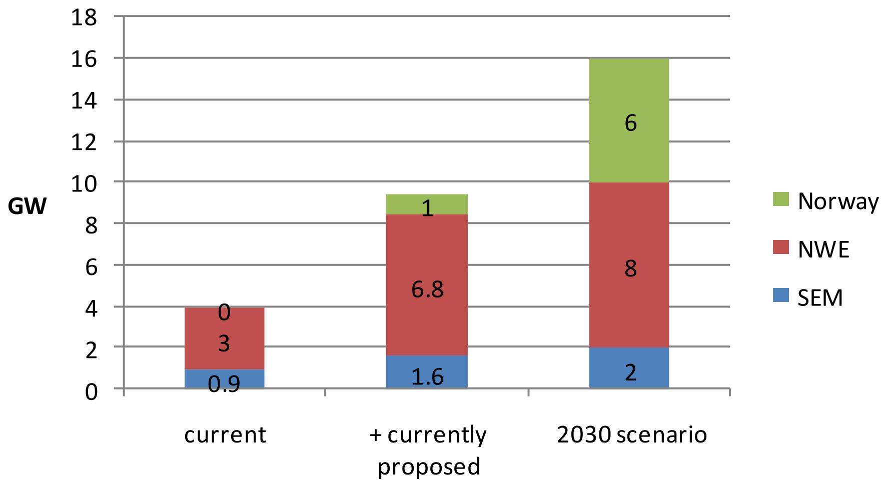

Figure 2 Increase in interconnection to GB network under the CCC's 50% renewables scenario.

[6] NERA-AEA (2010) Decarbonising Heat http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research

Inputs/assumptions

- Assumptions for flows have been determined by analysis outside the GB model, based on separate modelling by Pöyry in an intermittency study for North West Europe[7] which included weather across all of Northern Europe. The magnitude of flows has been scaled with changes in the level of interconnector capacity.
- No technical restrictions to operate interconnectors flexibly at an hourly resolution.
- Costs: £0.5bn/yr.

Uncertainties

- Supply through interconnectors is dependent on generation capacity being available elsewhere. During widespread low wind events, lasting several days and at times of high demand, the ability of NEW and Norway to provide power, when continental systems are also increasing their dependency on intermittent generation, is not clear. A separate report by Pöyry for the CCC looking at system flexibility (with an additional 6GW interconnection capacity) correlated GB and NW Europe wind data, suggesting that such an interconnector "would only provide limited flexibility, and could even make things worse at times." [8]
- The development of pumped hydro storage and the associated transmission network in Norway, for export of electricity to the UK and elsewhere, is not a given. As well as potential environmental, social, political and economic barriers, the UK will be in competition for the resource form other countries with similar needs.

C. Bulk storage

Extract from CCC Renewable Energy Review

"Bulk storage, such as pumped storage, can be used both to provide fast response and to help provide flexibility over several days (providing supply at times of peak daily demand rather than continuously over the whole period). In addition, investing in thermal storage alongside heat pumps can help shift electricity demand within the day and electric vehicle batteries can also be used as a form of electricity storage."

Key points from scenario

- Bulk storage is increased to 4GW generation capacity by 2030.
- Storage volume reaches 20GWh in 2030.[9]

Inputs/assumptions

- Nature of future storage is unspecified, but assumed to have same operating and cost characteristics of Dinorwig, an increase on the current 2.8GW capacity. See Figure 3 for current and proposed pumped storage facilities in the UK.
- Thermal storage (with HPs) and EV batteries are treated as moveable demand in the scenario.
- Costs: £0.6bn/yr, as for PHS

[7] Pöyry Energy Consulting (2010) How wind generation could transform gas markets in Great Britain and Ireland. Public summary http://www.Pöyry.com/media/media_2.html?Id=1301471113.html

[8] Pöyry (2010) Options for low-carbon power sector flexibility to 2050 http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research

[9] NB: current storage volume is *30*GWh, addition of energy storage facility with characteristics of Dinorwig to reach 4GW, would give 36GWh. See references for caption to Figure 3.

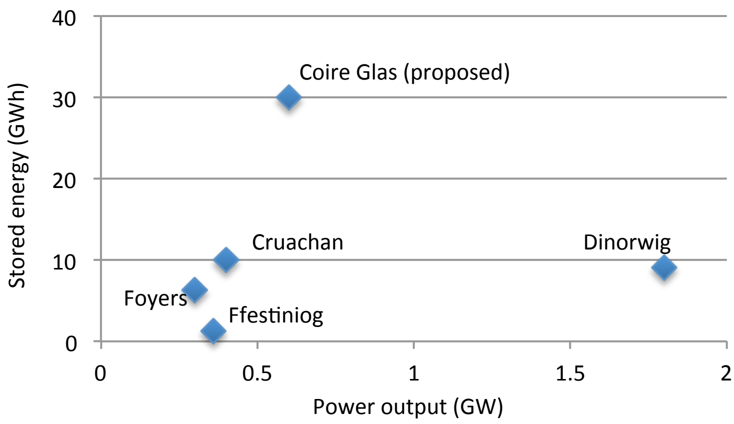

Figure 3 Current and proposed pumped hydro storage in the UK[10,11]

Uncertainties

The potential for the development of electrical storage technologies is not considered. Mass penetration of EVs could have the effect that battery technology is advanced enough by 2030 to have stationary applications at transmission/distribution/domestic level. Most energy system scenarios and models are limited in their ability to capture the potential benefit of energy storage.[12]

D. Balancing generation

Extract from CCC Renewable Energy Review

"Gas-fired generation offers the potential for balancing intermittent renewable generation. Assuming other flexibility options are deployed, Pöyry analysis suggests that residual balancing generation would be around 6% of total generation when all other generation is from renewables. This suggests that it is not possible to have a system running on 100% renewable electricity, although a very high renewable share would be technically feasible."

Key points from scenario

– Total installed capacity in 2030 (with nameplate wind generation) is 125GW, producing 440TWh/yr
– Operation of unabated fossil fuel generation varies between about 2 and 7 TWh/month over a year, with CCGT running at less than 20% load factor (Figure 4).
– There is no shedding of renewable generation, and less than 1% shedding of low variable cost generation (nuclear).
– No construction of CCGT beyond plant currently under development.

[10] MacKay (2009) Sustainable Energy – without the hot air http://www.inference.phy.cam.ac.uk/withouthotair/c26/page_191.shtml
[11] SSE (2012) Press release: http://www.sse.com/PressReleases2012/CoireGlasPlanningApplication/
[12] For further discussion see ERP (2011) The future role for energy storage in the UK http://www.energyresearchpartnership.org.uk/energystorage.

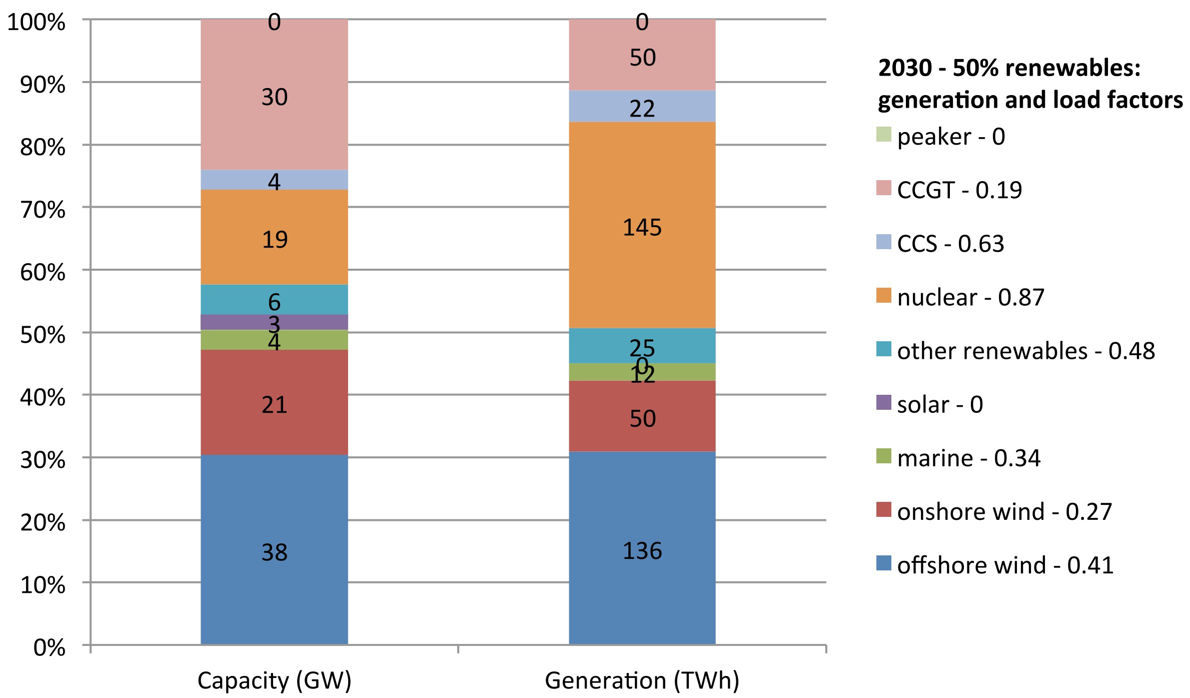

Figure 4 Electricity supply mix under CCC 50% scenario.

Inputs/assumptions

- Pöyry's deployment of non-renewable generation took into account existing plants (given expected closure schedule), plant currently under development and minimum requirements for new CCS and nuclear build provided by the CCC. They then used an iterative modelling process to inform decisions about the construction of additional plant (based on returns received) and the early closure of existing plant (where it was not recovering its fixed costs).
- Wind dominates renewable generation mix
- Costs: £0.02bn/yr for peaking capacity

Uncertainties

- Generation mix is achieved.
- Market framework makes running CCGT at low load factors a viable business case; overgeneration could be a common occurrence.

E. Sensitivities

Pöyry conducted several sensitivity runs of the model to explore the impact of reducing the flexibility options. The sensitivity runs provide some useful information, but do not analyse the effect on costs.

Impact of no demand side response

The absence of flexibility from EVs/PHEVs or heating was found to "significantly worsened system performance, with more peaking (and other thermal capacity) required, greater shedding and higher CO2 emissions". To maintain supply, the model calls for an additional 8GW peaking plant, 5GW CCGT (unabated), and 2GW nuclear. However, the model runs the high-carbon capacity infrequently and the nuclear with a high load factor, which actually reduces CO2 emissions by almost 10% in 2030. By 2050, though, as emissions drop in the main scenario, the variant cannot keep pace and ends up almost 30% higher.

Impact of no demand side response, with reduced interconnection

In this variant, on top of the reduced DSR described above, interconnection capacity was rescued from 15GW in the main scenario to 6GW (including GB-Norway dropping from 5.5GW to 1.4GW). A further 5GW of peaking plant is called for, and the high carbon power plants are operated more, leading to a 20% increase in CO2 emissions in 2030.

F. Case study – winter wind lull

Pöyry modelled the various renewables deployment scenarios using historic data of weather conditions from four different years. The example given in the figure below is with 50% renewables as in the scenario described above, in weather from February 2006. This has a period of low wind (with wind generating at <10% capacity) for three days, followed by high wind (near 100%) for two days (Figure 5). The first three days of the modelled period, for controllable supply, are expanded and annotated in Figure 6.

Balancing 30GW inter-day changes in demand is predominantly from CCGT, imports, and demand response including from EVs/PHEVs and thermal storage. CCGT operates near maximum over three days of low wind, with demand shifting across day/night periods, and interconnection providing hour-to-hour load following. Vehicle-to-grid provides additional generation capacity at peak times. There is a limited role for bulk storage.

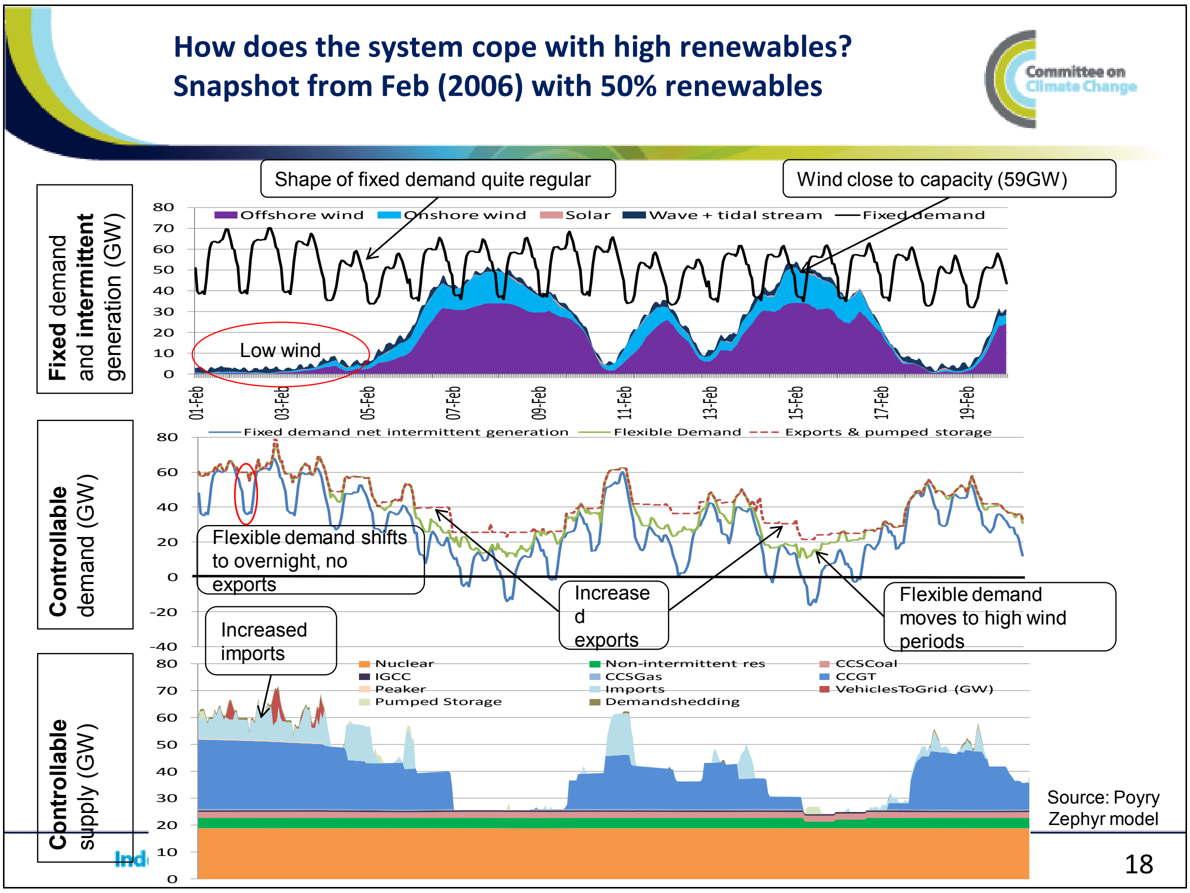

Figure 5 Modelled generation and demand response of CCC 50% renewables scenario to weather from February 2006.

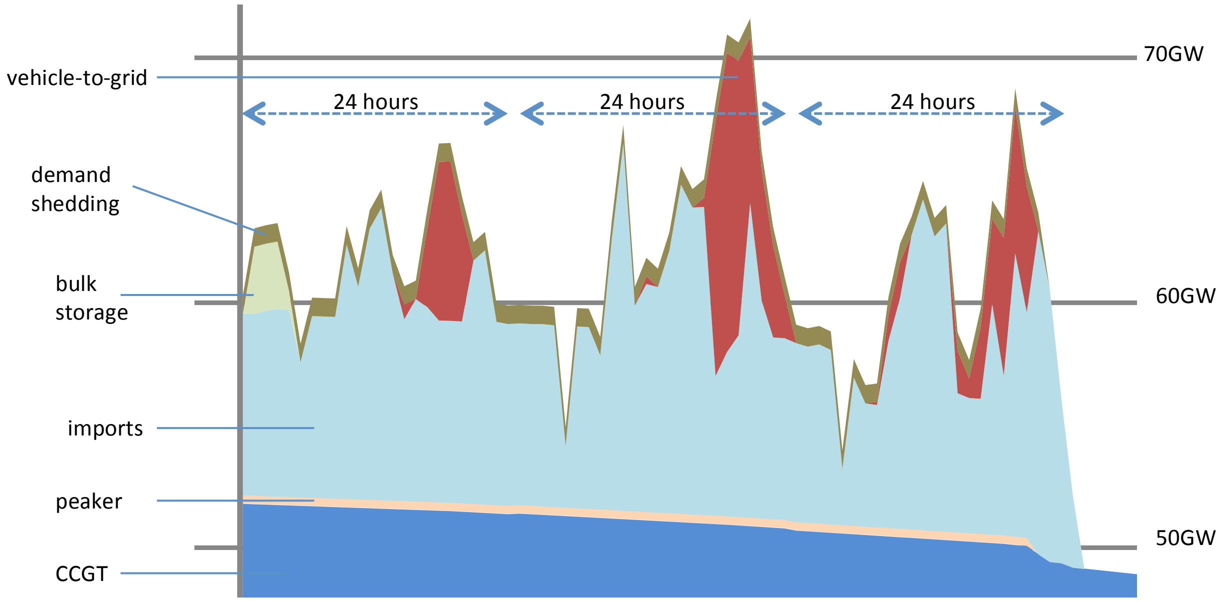

Figure 6 First three days of supply in Figure 5 expanded.

Comments on the response of flexibility options

Interconnection

- Over the course of the three day wind lull, the hourly averaged imported power is almost 8.5GW, peaking at 15GW, amounting to approximately 600GWh. The Pöyry model for North West Europe correlates continental weather patterns so that capacity is available for GB. However, there is still reliance on other European countries actually having this available generation capacity for export in 2030 through their own build programmes.
- Imports fluctuate significantly more than at present (see below for a current day case), with several instances of >10GW change in flow over interconnectors in less than 4 hours.
- Full capacity of the interconnectors looks to be used infrequently (from this snapshot). Load-duration curves would help show utilisation, and the viability of a business case for capacity at the margins without other incentives.

Vehicle-to-grid

- There is substantial, distributed, V2G power delivered at peak times in this case study.
    - V2G is called on in low-wind lull at peak demand, with power requirement up to 10GW for a period of 2-3hrs, and total energy delivered ~50GWh over 7 hours. CCC 4CB scenarios have 84GWh electrical energy supplied to transport each night in 2030; with 30% of fleet EV/PHEV (11m cars).
    - The model constrains V2G according to number of vehicles plugged-in and with sufficient charge (such that they still have enough energy for average mileage the following day, plus extra for range anxiety). The *average* EV 'contribution' to the grid over these periods would be around 5kWh with an 'upload' power up to 1kW. With not all EVs available for V2G at the 5pm peaks, this will have a commensurate effect on energy/power required from each

connected EV. (We would probably expect EV batteries to hold > 100kWh by 2030, to be comparable with current liquid fuel vehicles).
  - Battery EVs make-up 1/3rd of the EV/PHEV fleet, with PHEVs still the majority in 2030 (so providing a fuel-switching option).
- The amount of energy provided by V2G is quite a large proportion of the energy that is expected to be delivered *to* EVs each day, which would then have to be replenished on top of the expected amount plus efficiency losses (say 30% roundtrip losses), i.e. 84GWh + 50GWh + 15GWh.
- This large-scale distributed power generation would need to be considered in development of 'smart' grids (at transmission and distribution levels), and the roll-out of smart meters.
- The contribution of V2G is rarely at this level during the rest of the modelled year. Given this, the value of enabling V2G at all may be questionable: it would seem likely that V2G would require additional vehicle-based and distribution-network hardware to deliver the power, which if used infrequently may not justify the expense.

Thermal storage
- CCC 4CB has 51TWh/yr electrical energy demand by HPs in 2030, which would amount to around 200GWh/day in the winter. The Pöyry model assumes 150GWh/day moveable electrical demand from heating in the winter, 50GWh/day of which would be from HPs – a significant proportion of installed demand requiring storage. If it was provided by domestic sector, with HPs in 25% of properties, and 25% of these with thermal storage, the average shifting would be about 30kWh (equivalent to almost 600l of stored hot water) in each property.

Bulk storage
- Energy storage in the wider sense, including thermal and distributed electricity storage (in EV/PHEV), is made good use of in the model, though bulk electrical energy storage plays a very limited role in this case study despite substantial new storage having being developed. Though this is a limited snapshot, it raises questions whether the model reflects the actual operation of the system – a new highly capital-intensive resource such as energy storage, once built would likely be in use as much as possible. The Zephyr model has hourly resolution, so doesn't show the value new storage may attract from short time-scale ancillary services, but should pick-up inter-day arbitrage.
- In the figures presented by CCC above, storage appears to generate away from peaks, and not be generating at peak times, which is incongruous.
- Demand shifting appears to be a more efficient method of load levelling. This shows the tension between the potential of significant demand side response (effectively very distributed energy storage which would require deployment strategies to implement) and dedicated 'electrical' storage (either mature PHS technology which has limited opportunity for expansion, or new technologies which are yet to be cost-effective).

System operation
Operationally, the above scenario is a significant shift from current system management, which uses power generation (especially gas and PHS, coal to a lesser extent) to follow demand, and imports relatively constant. An example from 7 January 2010 is given in Figure 7, and contrasted with a day from the case study in Figure 8.

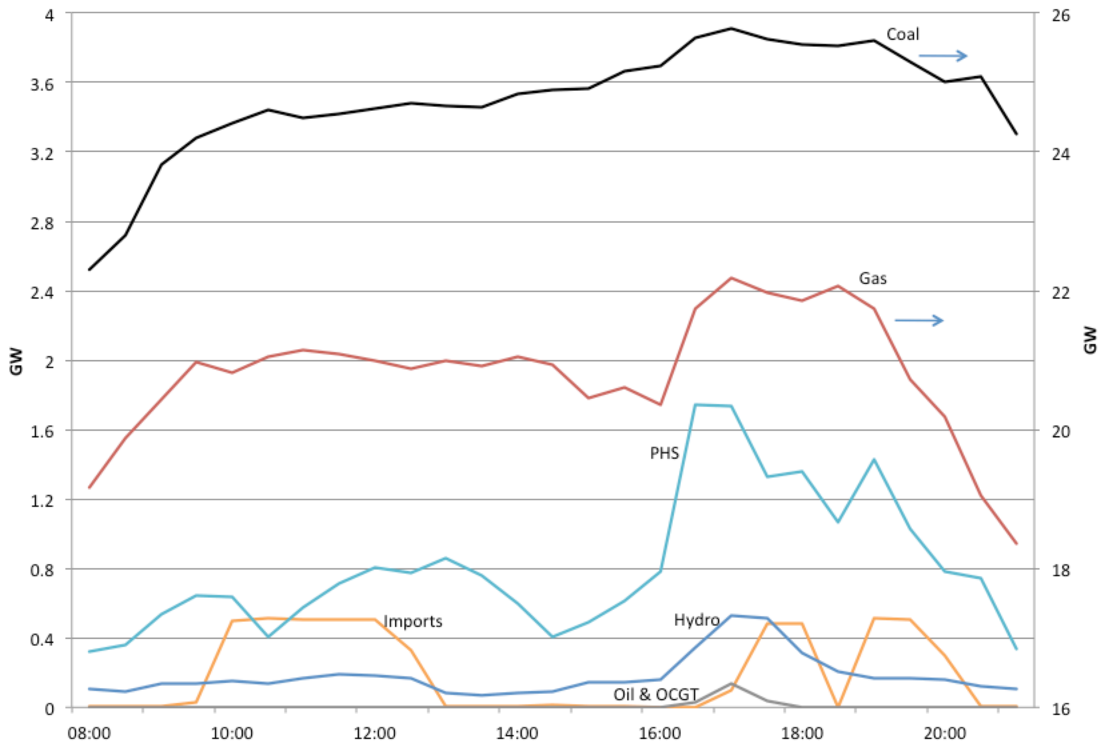

Figure 7 Actual supply profile for 7 January 2010. Gas and coal shown on right-hand axis, all other sources use left-hand axis. Nuclear (which is slowly varying around 8GW) and wind (negligible on this day) are not shown. (Source: National Grid)

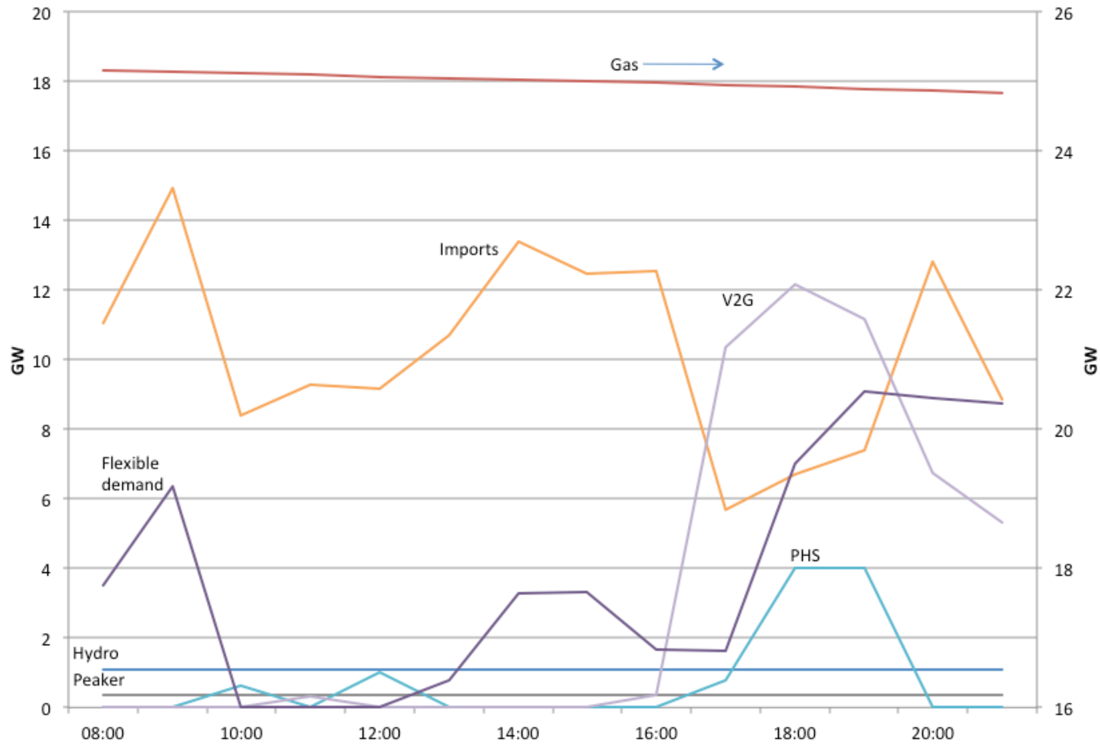

Figure 8 Modelled profiles for 2 February 2030 from the case study with 50% renewables (see Figure 5), during a low wind event (total wind generation is less than 1GW, not shown). Note the left hand scale is x5 that of the previous figure (Source: Pöyry)