Energy

Role of distributed storage in a 100% renewable UK network
Alexander and James

ice | proceedings

Proceedings of the Institution of Civil Engineers

http://dx.doi.org/10.1680/ener.14.00030
Paper 1400030
Received 30/09/2014 Accepted 20/02/2015
Keywords: economics & finance/energy/renewable energy

Role of distributed storage in a 100% renewable UK network

Marcus Joseph Alexander MEng
EngD Researcher, Faculty of Engineering and Environment, University of Southampton, Southampton, UK

Patrick James BSc, PhD
Professor of Energy and Buildings, Faculty of Engineering and Environment, University of Southampton, Southampton, UK

DOI: 10.1680/ener.14.00030

Title: Role of distributed storage in a 100% renewable UK network

Author 1

- Marcus Joseph Alexander, EngD Researcher
- Faculty of Engineering and Environment, University of Southampton, Southampton, UK

Author 2

- Dr Patrick James, Professor of Energy and Buildings
- Faculty of Engineering and Environment, University of Southampton, Southampton, UK

Full contact details of corresponding author:

Marcus Joseph Alexander

Faculty of Engineering and Environment

University of Southampton

SO17 1BJ

Email: mja105@soton.ac.uk

Abstract

This study considers generation and demand challenges in a 100% renewable UK electricity grid and poses the question whether this can be addressed through the use of distributed energy storage. To explore this issue, hourly demand and electricity generation profiles for a year have been constructed for a variety of renewable sources and demand scenarios. Alongside baseline projections, further scenarios have been produced that include extensive uptake of electric heat pumps for domestic heating and hot water, as well as moderate uptake of electric vehicles. It is proposed that these technologies are used on a local scale to help integrate the additional renewable electricity generated within a pre-determined zone of the electricity network. Analysis has been carried out to determine the pinch points in the UK network where renewable electricity generation is greater than local electricity demand. From this, consideration has been made to understand the real impact distributed energy storage in the form of heat pumps and electric vehicles can have in helping balance a 100% renewable UK electricity grid. Initial results have found that depending on the demand scenario and location on the network, there is the potential to accommodate up to 50% of the excess electricity generated.

Keywords

Energy, renewable energy and economics & finance

List of notation

ASHP	air source heat pumps, technology suitable for providing heating from electricity
BAU	business as usual, scenario whereby electricity demand increases by 1% yearly
CAPEX	capital expenditure, cost to install a technology
COP	coefficient of performance, ratio of heating or cooling provided to electrical energy consumed
EV	electric vehicle, in this definition includes any battery electric and plug-in hybrid vehicle

GP green plus, scenario whereby electricity demand increases by 0.25% yearly after a period of decline

GW gigawatt = 1,000 megawatts, unit of power (capacity)

H2 hydrogen storage, defined as the process of producing hydrogen from cheap/excess electricity, storing it and then re-using it when needed

LAES liquid air energy storage, technology that cryogenically condenses air to store excess/cheap electricity

LV low voltage, electricity network on the distribution side maintained and operated by the distribution network operator

MW megawatt, unit of power (capacity)

PHES pumped hydro energy storage, technology that uses the potential energy in water and reservoirs at different levels to store/generate electricity

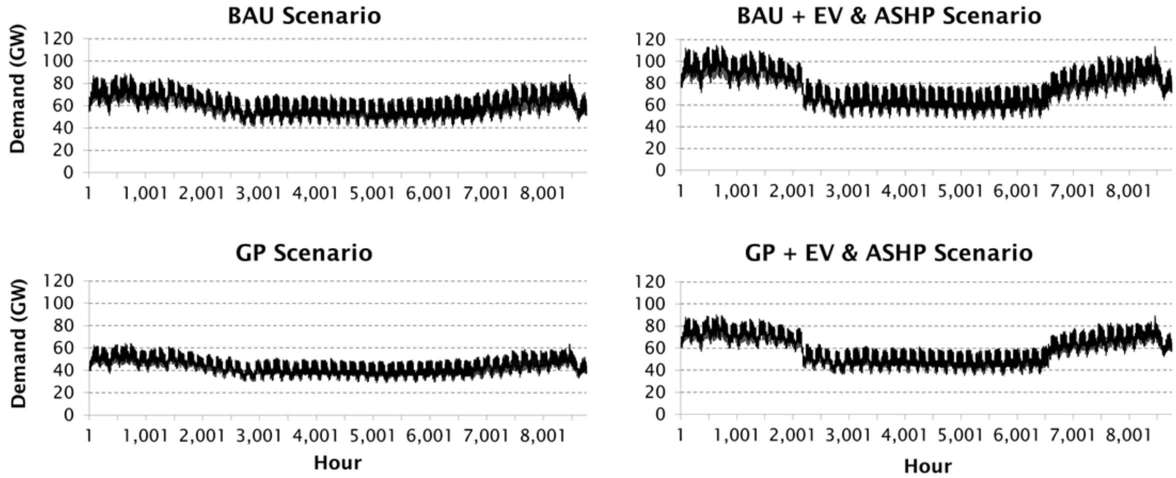
TWh terawatt hour = 1 million megawatt hours (MWh), unit of energy

1. Introduction

An extensive de-carbonisation of the energy supply sector as is highlighted by the targets set by the European Commission Roadmap 2050 (EC, 2011) will be required in the future. The UK Low Carbon Transition Plan (DECC, 2009) includes energy sources such as wave, tidal, geothermal and solar, but mainly onshore and offshore wind as likely technologies to provide carbon free electricity generation. These sources are, by their very nature, variable and in most cases unpredictable over long time periods which creates challenges for distribution, grid stability and standby plant (Milborrow and Gonzalez, 2003). At present, the real-time balancing of the supply and demand of electricity on the electricity grid is carried out by flexible fossil fuelled power plants which are capable of increasing or decreasing output rapidly as required by the grid operator. However, in a future electricity network supplied only by renewable sources, this balancing will have to be achieved using alternative methods and technologies.

In previous work by the authors studying a 100% renewable UK electricity grid (Alexander et al., 2014), the balancing options proposed were interconnection with neighbouring electricity networks and large-scale bulk energy storage technologies such as pumped hydro (PHES), liquefied air energy storage (LAES) and hydrogen (H2). To arrive at this, a number of electricity supply and demand scenarios have been formulated to enable potential views of the needs and requirements on the network. These are based on hourly demand and generation profiles derived from actual 2011 data and scaled to meet the future requirements (Alexander et al., 2014). An hourly time step has been chosen to reduce the computational time required in modelling a full year's simulation. Additionally, energy resource modelling should be based on simulations with a time step of no courser than one hour as it has been shown that there are large differences in output/model fidelity with larger time steps (Hovenaars, 2009). The demand scenarios proposed include two baseline scenarios suggested by (Elders et al., 2006) to which two further scenarios have been added that includes estimates for the uptake of electrification of domestic heating and transportation. The demand profiles for these scenarios are outlined in Figure 1.

Figure 1: Hourly electricity demand scenarios (Source: Alexander, et al. 2014)



The estimated capital expenditure (CAPEX) costs per scenario have also been calculated using projected technology capital costs for 2030 (Arup, 2011, Ernst&Young, 2010). Note that these costs represent the full cost of installing the required future renewable capacity if it were to be commissioned and installed in one year. The scenarios and costs described are summarised in Table 1.

Table 1: Scenario electricity demand (TWh), assumed practicable resource capacity (GW) and generation (TWh) and calculated mix for each scenario: Business as Usual (Radov et al.), Green Plus (GP), BAU with electrification of heating and transportation (BAU+ASHP&EV) and GP with electrification of heating and transportation (GP+ASHP&EV) (Elders et al., 2006, Gardner, 2011))

Technology	BAU (GW/TWh)	GP (GW/TWh)	BAU + ASHP & EV (GW/TWh)	GP+ ASHP & EV (GW/TWh)
2050 electricity demand (TWh)	540	390	677	527
Onshore wind	30/65	30/65	30/65	30/65
Offshore wind	86/288	41/138	127/425	82/275
Solar PV	34/37	34/37	34/37	34/37
Tidal	2/7	2/7	2/7	2/7
Bioenergy	14/95	14/95	14/95	14/95
Hydro	2/13	2/13	2/13	2/13
Geothermal	5/35	5/35	5/35	5/35
Estimated scenario CAPEX (£Bn)	280	200	353	273

This work concluded that for the BAU scenario, an interconnector capacity totalling 60 GW costing in the region of £58 billion would be sufficient to balance the supply and demand requirements throughout the year. Note that this would be dependent on the neighbouring European electricity network being capable of accommodating these levels of import and export. The second option discussed is the bulk energy storage options. The conclusions in this case are that for the BAU scenario the optimum solution would be 65 GW of rated hydrogen capacity and 13,645 GWh of hydrogen storage in underground caverns requiring an extra 5 GW of installed offshore wind capacity. This would add an extra cost to the scenario in the region of £45 billion. However, due to the current uncertainties in this technology, a relatively more conservative solution employing PHES is proposed consisting of 4 GW of rated pumped storage capacity (864 GWh storage capacity) with an extra offshore wind capacity of 38 GW at an estimated additional cost of £72 billion.

The present paper will employ the BAU electricity supply and demand scenario developed in (Alexander et al., 2014) to understand the impact on the network boundary capacity required. It also considers the impact that energy storage on the local network will have as well as estimate the level of variable renewable generation that can be absorbed before extensive network upgrading is required.

2. Existing UK transmission grid suitability

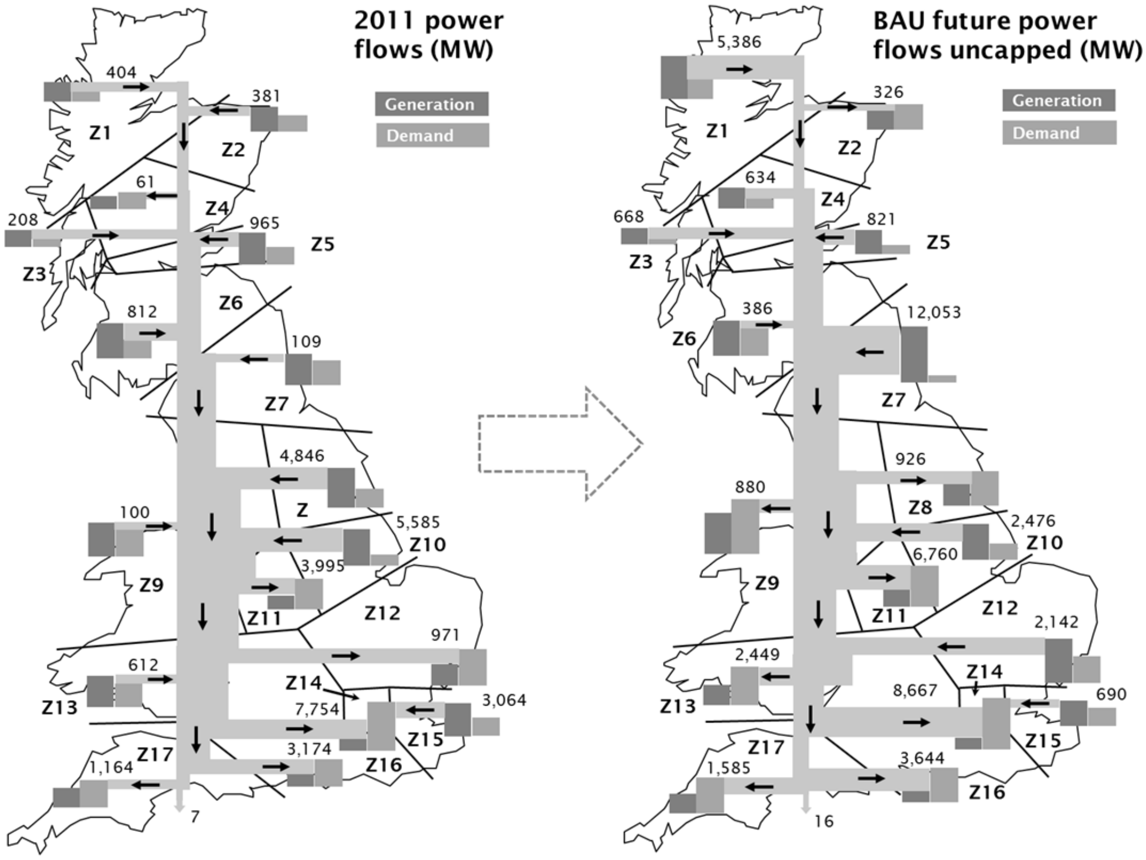
To enable a better understanding of the demand requirements within the UK network, National Grid, the network operator, has divided the network using 17 boundaries which confine areas or zones within the grid that are considered as blocks that have their own generation and demand requirements (NationalGrid, 2013). The relationship between boundaries and zones is given in Table 2.

Table 2: GB Transmission System Boundaries (NationalGrid, 2013)

Boundary n°	Zone n°
B1	Z1
B2	Z1, Z2
B3	Z3
B4	Z1, Z2, Z3, Z4
B5	Z1, Z2, Z3, Z4, Z5
B6	Z1, Z2, Z3, Z4, Z5, Z6
B7	Z1, Z2, Z3, Z4, Z5, Z6, Z7
B8	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9
B9	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9, Z10, Z11
B10	Z16, Z17
B11	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8
B12	Z13, Z16, Z17
B13	Z17
B14	Z14
B15	Z15
B16	Z1, Z2, Z3, Z4, Z5, Z6, Z7,Z8, Z10
B17	Z11

It is of note that these zones can change over time as they are dependent on the characteristics, mix and location of electricity generation. Therefore, in a future fully renewable electricity grid, the location of electricity generation will undoubtedly be different. However, it is assumed that this remains unchanged in the present study. The system zones are depicted in Figure 2. Each zone has a number of electricity generators within it. However, not all generation in each zone is consumed within the zone; therefore in some cases there is a transmission of excess generation to neighbouring zones where there is a demand. This produces power flows between zones around the network towards the centres of consumption in cities and generally from North to South in the UK. From the work carried out for (Alexander et al., 2014), it is possible to have a breakdown of expected generation by network zone. Figure 2 provides the net power flows on the UK network in 2011 (NationalGrid, 2011)) and the estimated power flows in the BAU scenario. It is apparent that in the future scenario, the overall flow of electricity is still towards the South however, the magnitude is much greater. It is also possible to appreciate the extent of increase in the gap between generation and demand in certain zones.

Figure 2: Average electricity power flows across the UK network in 2011 (adapted from (NationalGrid, 2011)) and calculated for 2050 BAU scenario (Alexander et al., 2014)



Due to the large increase in the calculated offshore wind capacity in the BAU scenario there are larger generation exports from zones 1, 7 and 12 implying that the transmission network in these zones would require upgrades to ensure the electricity can be transported to where it is required. These bottlenecks could also be ideal locations for targeted bulk energy storage installations to ease network congestion and defer transmission upgrades or, as investigated in the present paper, distributed energy storage.

2.1. Zonal analysis and constraints

The electricity network capacity is closely monitored and administrated by National Grid. The National Electricity Transmission System (NETS) Seven Year Statement 2011 report has analysis on the available electricity network capacity within the zones and also sets out the proposed capacity upgrades to 2018 (NationalGrid, 2011). This baseline has been chosen to maintain consistency with the assumptions used in creating the BAU scenario supply and demand requirements. The NETS statement enables an estimate of the effect of increases in installed capacity on the network. It is assumed that demand within each zone is scaled linearly to meet the assumed demand projections in the future. This exercise provides a view of the likely capacity upgrade necessary within each zone to be able to cope with the increased generation from renewable sources. Table 3 provides a summary of the BAU scenario electricity transfer required between each boundary and the proposed upgrades (SYS capability). The shortfall is given as new transfer capacity. In some instances, it was found that the planned increases are sufficient to accommodate the increase in generation capacity, and hence are given a null value. However, for the instances where new capacity is required, the cost of such is estimated.

Due to the intricacies of electricity network connection and the commercially sensitive information, the costing of the upgrade is given here as an indicative cost. This is based on a value of £44,394 per MW capacity which has been calculated from information provided in (Sterling et al., 2012). It is further assumed that all boundary upgrades are carried out by increasing the transfer capacity of existing infrastructure. This gives a guideline cost to increase the network capacity to account for the increase in renewable generation of £2.2 billion.

Table 3: Investigation of the network transfer capacity in the BAU scenario and the amount of investment required to meet it. Note, negative future transfer values denote import requirement (NationalGrid, 2011, Sterling et al., 2012))

Boundary	Future transfer (MW)	SYS capability (MW)	New transfer capacity (MW)	Cost (£ million)
1	5,386	2,300	3,086	£137
2	5,060	3,400	1,660	£74
3	668	500	168	£7
4	6,361	3,650	2,711	£120
5	7,182	5,350	1,832	£81
6	7,568	8,050	-	-
7	19,620	6,600	13,020	£578
8	17,814	11,035	6,779	£301
9	13,529	10,985	2,544	£113
10	- 5,229	6,167	-	-
11	18,694	9,556	9,138	£406
12	- 7,679	4,804	2,875	£128
13	- 1,585	3,264	-	-
14	- 8,667	9,849	-	-
15	690	6,121	-	-
16	21,170	16,909	4,261	£189
17	- 6,760	5,706	1,054	£47
Total investment required for BAU scenario				£2,181

It is of interest to investigate potential solutions that could defer or in fact eliminate the necessity to carry out this expensive network upgrading. The study now considers energy storage solutions on the local scale to understand what impact they could have to enable the integration of renewable generation on the network.

3. Distributed energy storage solutions

As introduced, the previous study by the authors considers four future electricity demand scenarios. Two of these include electrification of heating and transportation. It is proposed in the present paper to investigate the suitability and scale of electricity storage that the uptake of electrification can provide to the future UK electricity network. It is assumed that these systems will be connected to the low voltage distribution network and therefore the necessary transmission and distribution systems within each zone are sufficient to be able to transfer the electricity from the generator (connected to the transmission network) to the ‘store’ and vice versa. In this discussion, the ‘store’ refers to the amount of electricity storage in the battery of an electrified vehicle and the thermal store within a domestic property.

3.1. Domestic heating and hot water

For this study it has been assumed that there is a mass uptake of domestic heat pumps to supply all space heating. This can be supplied by a number of heat pump technologies, however in this case it has been assumed that the technology used is air source heat pumps (ASHP) with a coefficient of performance (COP) of 3.5 as detailed in Cabrol and Rowley (2012). As well as supplying space heating, it has also been assumed that ASHP can supply a portion of domestic hot water demand.

To calculate the amount of energy available for storage, some future projections of the make-up of the domestic housing stock was used. Projections put the number of houses in 2050 to increase to circa 34 million properties. This figure takes into account a demolition rate of 0.1% per year (assumed demolition rate from DECC) and a new build of 9 million properties as given in Arran and Slowe (2012) was used. This equates to 27% of the future stock being new build whereas the remainder are made up of existing buildings. The zonal distribution of the building stock in 2050 has been assumed to be linearly scaled from the 2011 census information (ONS, 2012, GRO-Scotland, 2012). This distribution can be seen in Table 4.

From Boardman et al. (2005) it has been taken that heat demand from existing buildings is 6,800 kWh per dwelling per year (which includes insulation of 100% of all cavity walls and loft insulation, 15% of solid walls and upgrading all windows to high-performance windows) whereas for new build this is 2,000 kWh per dwelling per year. Taking into account the spread of housing given, this equates to a total heating demand in the region of 187 TWh per year. As it is proposed that all this demand be supplied by ASHP, the total electricity demand is 53 TWh due to the increased efficiencies from this technology.

For hot water contribution, it has been assumed that daily hot water demand in the UK is 7.2 kWh per day per house, based on a household of four people and an electricity demand of 1.8 kWh for 45 litres at 45°C (Panasonic, 2013), of which 4.5 kWh per day per house can be supplied by ASHP. This assumption is made due to the high temperature required for domestic hot water supply. The remainder of the demand is assumed to be supplied from immersion heaters, making it a two stage heating system. Given the COP of this technology, the amount of electricity demand for hot water is calculated to be in the region of 16 TWh.

This gives a total figure of 69 TWh of electricity demand for heating and hot water. For this discussion, it has been assumed that the grid operator has full control of this demand during the winter months (October to March) to be able to use this to balance supply and demand from renewable sources throughout the year.

3.2. Electric vehicles

A potential second source of energy storage is within the batteries contained inside electric vehicles. In the scenario discussed, it is assumed that by 2050 there will be an increase in the uptake of electric vehicles in the UK. Note that in this study, electric vehicle (EV) constitutes any battery powered vehicle that is able to connect to the electricity grid to charge/discharge energy. Work carried out by Hassett et al. (2011) suggests that by 2050, there is the potential for 7 million vehicles on the roads to be electric, 70% of which would be plug-in hybrid vehicles (PHEV) and 30% pure battery electric vehicles (Crossley and Beviz).

It has been assumed that the average battery capacity of a PHEV is 9 kWh (based on the average of the battery capacity of the Toyota Prius plug-in, Chevy Volt and BMW i8) whereas for a BEV battery capacity is assumed to be 24 kWh (Nissan, 2014)). It is also assumed that battery charging and discharging efficiency is 80%. Based on vehicle utilisation of 50 weeks per year, with four full charge/discharge cycles per week. The total amount of electricity demand from EV is in the order of 34 TWh if all vehicles are plugged-in and charging.

This electricity demand can also be considered as a potential store as, with the right control systems in place, the grid operator could call upon these reserves to balance shortfalls and excesses in renewable generation. This also has a benefit as vehicles are likely to be geographically dispersed, following a similar pattern to the spread of households. However, due to the current limitations in battery technology impinging on the range that these vehicles are able to travel, it is proposed that EV are mainly located in urban areas. For this reason, the spread of EV has been calculated based on the ratio of households in each zone over the total in the UK thereby giving a scale that ranges from 0.2% in areas of Scotland to 14.8% in Zone 9. This trend can be appreciated in Table 4.

3.3. Total distributed energy storage potential in the UK

The amount of ‘storage’ that can be provided through the uptake of ASHP to supply heating and hot water and the potential collective battery store in EV have been calculated above. Table 4 shows the distribution of this ‘storage’ across the zones of the UK network based on housing census data. As can be seen, the total amount of distributed storage in the UK is in the region of 103 TWh per year. From the work carried out in (Alexander et al., 2014) it was calculated that for the BAU scenario, a bulk energy storage technology with a maximum storage capacity of 13.6 TWh was required. If all this potential can be used, there would be sufficient storage capacity on the electricity network.

It is useful to understand the amount of demand, and hence storage, available within each zone as this will be used as the basis for further investigation into the potential for these technologies to be able to absorb excess generation from renewable sources.

Table 4: Zonal distribution of storage from domestic heat pumps and electric vehicles in the BAU scenario

Zone	2011 households	Future households	Spread of EV	ASHP store (MWh)	EV store (MWh)
1	188,173	246,338	50,947	503,928.73	248,477
2	220,520	288,683	59,705	590,554	291,190
3	46,679	61,108	12,638	125,007	61,638
4	236,109	309,091	63,926	632,302	311,775
5	352,714	461,739	95,496	944,571	465,749
6	1,444,301	1,890,739	391,040	3,867,849	1,907,159
7	1,351,900	1,769,777	366,023	3,620,399	1,785,146
8	2,224,100	2,911,577	602,168	5,956,157	2,936,861
9	3,832,300	5,016,876	1,037,584	10,262,929	5,060,444
10	1,681,800	2,201,650	455,342	4,503,873	2,220,769
11	1,557,400	2,038,797	421,661	4,170,729	2,056,503
12	2,016,600	2,639,938	545,988	5,400,470	2,662,863
13	2,784,700	3,645,460	753,949	7,457,448	3,677,118
14	3,266,200	4,275,793	884,314	8,746,909	4,312,925
15	1,430,500	1,872,672	387,304	3,830,890	1,888,935
16	1,945,000	2,546,206	526,603	5,208,725	2,568,318
17	1,275,400	1,669,630	345,311	3,415,531	1,684,130
	25,854,396	33,846,075	7,000,000	69,238,270	34,140,000

4. Analysis of constrained zone and effect of distributed energy storage capacity

Here the total maximum technical capability of storage within each zone to absorb renewable generation will be investigated. To do this, it is proposed that the worst pinch points on the network are investigated in greater detail. These are created where there is a large amount of generation from renewables, in most cases from offshore wind, which needs to be distributed to where there is a demand or where there is a large demand from densely populated areas and not enough generation.

From the analysis previously carried out on the generation and demand flows on the future network it has been identified that the worst pinch points created are, in order of severity, at the boundaries of zones 7, 1 and 12. These have been chosen as there is the largest imbalance between electricity generated, which is driven by the increase in generation from offshore wind farms connecting to the network in these zones, and the demand within these zones. There are two notable zones which have a reverse effect, which is that demand is much higher than generation. This is the case with zones 11 and 14, which are the zones encompassing Birmingham in the midlands and Greater London. For the discussion in this paper, these have not been considered as the focus is on assessing the maximum potential storage available in zones where there is a large increase in generation. Though it is noted that there is a large storage potential within these zones as they are major urban areas and that this could be used to minimise peak transmission capacity requirements.

The analysis investigated the amount of installed capacity and the respective generation from the different renewable sources that would be within the zone over the course of the year. This was compared to the demand from within the zone, which is driven by the forecasted increase introduced earlier. From this, the amount of excess generation can be determined. From the investigation carried out into the zonal ‘store’ from the electrification of domestic heating and transportation, it is possible to determine how much of the excess generation can be absorbed within the zone assuming all of this potential ‘store’ can be utilised. Table 5 shows the results for the BAU scenario with associated ASHP and EV. It can be seen that in the case of Zone 7, only 8% of the imbalance generation can be absorbed. This is driven by the large capacity of offshore wind expected to be developed in the waters east of this zone. The result for Zone 1 is similar in scale (3% excess generation absorbed); however in this case, there is a smaller demand and amount of ‘storage’ within the zone due to a lower population. On the other hand, the results for Zone 12 show that a significant proportion of the generation (65%) can be absorbed within the zone. This is due to the high population within this zone.

Table 5: Analysis of storage availability within zones and amount of generation that could be absorbed in the BAU plus air source heat pumps (ASHP) and electric vehicles (EV) scenario

BAU + ASHP & EV	7	1	12
Imbalance between generation and demand (MW)	16,461	6,534	3,949
Generation imbalance (MWh)	70,579,501	21,498,786	12,342,269
Storage within zone (MWh)	5,405,544	752,406	8,063,334
Excess generation absorbed (%)	8%	3%	65%
Storage within neighbouring zones (MWh)	29,991,399	2,012,467	39,508,575
Excess generation absorbed including neighbour zones (%)	50%	13%	+100%

The effects of considering the neighbouring zones have also been investigated. This would have the net effect of being able to distribute the excess generation across a larger portion of the population. However, it is important to note that in this case, there would need to be investment made to increase the line capacity between neighbouring zones to account for this. It is now possible to see how the excess generation from Zone 7 can be distributed between Zones 6, 8 and 9 also (as depicted in Figure 2). With this extra storage capacity, up to 50% of the excess generation can be absorbed. In the case of Zone 1, due to the location on the network, only a relatively modest amount of generation can be absorbed within Zones 2, 3 and 4 (13%). Whereas for Zone 12, the location on the network is favourable as there is a larger proportion of population, which means that all of the excess generation can be absorbed.

The same analysis has been carried out for the GP with ASHP and EV scenario. Table 6 gives a summary of the findings. In this case, the amount of generation in each zone is lower than the previous scenario but also the demand. This means that there is still a measure of excess generation that needs to be absorbed. In this scenario, Zone 7 along with its neighbouring zones can absorb up to 71% of the excess generation. In Zone 12, it would be possible to absorb all the excess generation within the constraints of its own zone. This would be the best possible case for distributed storage from ASHP and EV to be able to ensure the supply and demand of renewables is feasible.

Table 6: Analysis of storage availability within zones and amount of generation that could be absorbed in the GP plus air source heat pumps (ASHP) and electric vehicles (EV) scenario

GP + ASHP & EV	7	1	12
Imbalance between generation and demand (MW)	11,615	5,272	1,961
Generation imbalance (MWh)	50,110,478	17,491,080	5,909,117
Storage within zone (MWh)	5,405,544	752,406	8,063,334
Excess generation absorbed (%)	11%	4%	+100%
Storage within neighbouring zones (MWh)	29,991,399	2,012,467	39,508,575
Excess generation absorbed including neighbour zones (%)	71%	16%	+100%

It has been shown that in most cases, there is not enough storage within each zone to be able to accommodate the proposed levels of renewables required to ensure all the electricity demands are met. It would require the addition of neighbouring zones within the boundary, or indeed across boundaries, to be able to absorb greater amounts of generation. However this would require additional investment to increase the network capacity to be able to cope with the increases in power flows.

Further steps necessary would be to calculate a likely estimated cost of HV and LV cables for each case to ensure that the electricity network within each zone can cope with the additional renewable generation. There also needs to be an investigation into the capability of the distribution network in accommodating the amount of generation discussed here and the costs and/or feasibility of control systems to be able to regulate these flows. Another aspect which is not considered is the business model for the grid operator being able to control the amount of storage within the battery of an EV, affecting the personal usage of the vehicle, or controlling temperatures within households. However, it is expected that flexible control of electrical loads and two-way flow of electricity will become prevalent in the future network, especially in the GP based scenarios where household smart metering and options for time-of-use tariffs will be employed.

5. Discussion and conclusions

From this analysis it is seen that with sufficient uptake of electrification of domestic heating and transportation a significant level of renewable electricity generation can be accommodated onto the existing network. However, it is important to note that a proportion of the network would need to be upgraded to allow for bi-directional electricity flows on a large scale as well as the mass roll out of smart control systems to be able to regulate this.

It was found that, dependant on the location on the electricity network and the future scenario discussed, anywhere from 3% to 100% of excess generation could potentially be absorbed into the local network.

It is likely that any future electricity scenario that has 100% of its electricity generated from renewable energy sources will employ a combination of methods and technologies to account for the variability of this supply. Distributed storage will play a major role alongside large scale storage and increased interconnection with neighbouring networks. Demand side management will have, and already has in the industrial and commercial energy sectors, an important role to play in the domestic energy sector.

Further work needs to be carried out to investigate the compatibility of domestic heating requirements and electric vehicle usage with the variability of electricity supply on the network. The energy services associated with these devices that are being proposed must be provided reliably on a daily basis and the limitations of the energy 'store' to be available when there is a surplus or deficit of generation. There is a seasonal variation to the heating demand in the UK which could have an adverse effect on the amount of storage available. The colder temperatures during winter months also have an effect on the amount of energy available in the battery of a vehicle, meaning that there would potentially be less storage capacity available to the grid. During the winter months, electricity demand is higher due to the increased need for artificial lighting and electric space heating. The modelled scenarios have defined the required capacity based on this higher demand during the winter. However, due to the relative unpredictability of wind resources, the effects of there being a low resource are heightened. There is however a clear seasonal link present between higher availability of wind generation and an increased demand for household heating. Another concern relating to the amount of storage that is available from vehicles plugged into the network is the number of vehicles connected at any one time. In addition, another consideration to take into account is the amount of battery energy that will be available due to the owner needing to use the vehicle.

Clearly these issues need to be addressed for this technological solution to be feasible. There is a large volume of research and technical trials being carried out that are investigating this feasibility and how these systems can interact with each other to ensure a secure and stable network.

Acknowledgements

The authors would like to acknowledge the support of the Engineering and Physical Sciences Research Council (EPSRC) and the University of Southampton.

References

ALEXANDER, M., JAMES, P. & RICHARDSON, N. 2014. Energy storage against interconnection as a balancing mechanism for a 100% renewable UK electricity grid. *IET Renewable Power Generation,* 8**,** 11.

ARRAN, J. & SLOWE, J. 2012. 2050 Pathways for Domestic Heat - Final Report. Delta Energy & Environment (Delta-ee).

ARUP 2011. Review of generation costs and deployment potential of renewable electricity technologies in the UK. London: Ove Arup & Partners Ltd.

BOARDMAN, B., DARBY, S., KILLIP, G., HINNELLS, M., JARDINE, C. N., PALMER, J. & SINDEN, G. 2005. 40% House. Oxford: Environmental Change Institute.

CABROL, L. & ROWLEY, P. 2012. Towards low carbon homes - A simulation analysis of building-integrated air-source heat pump systems. *Energy and Buildings,* 48**,** 127-136.

CROSSLEY, P. & BEVIZ, A. 2010. Smart energy systems: Transitioning renewables onto the grid. *Renewable Energy Focus,* 11**,** 54-56.

DECC 2009. Smarter Grids: The Opportunity. *In:* CHANGE, D. O. E. A. C. (ed.). London: Crown Copyright.

EC. 2011. *Roadmap 2050 - Sectoral perspective* [Online]. European Commission. Available: http://ec.europa.eu/clima/policies/roadmap/perspective/index_en.htm [Accessed September 2012].

ELDERS, I., AULT, G., GALLOWAY, S., MCDONALD, J., KOHLER, J., LEACH, M. & LAMPADITOU, E. 2006. Electricity Network Scenarios for Great Britain in 2050. Glasgow: Institute for Energy and Environment.

ERNST&YOUNG 2010. Cost of and financial support for wave, tidal stream and tidal range generation in the UK. Ernst & Young LLP and Black & Veatch.

GARDNER, P. 2011. UK generation and demand scenarios for 2030. Glasgow: Garrad Hassan & Partners Ltd.

GRO-SCOTLAND. 2012. *Household Estimates* [Online]. General Register Office for Scotland. Available: http://www.gro-scotland.gov.uk/statistics/theme/households/estimates/index.html [Accessed March 2013].

HASSETT, B., BOWER, E. & ALEXANDER, M. 2011. MERGE WP 3 Task 3.2: Evaluation of the impact that progressive deployment of EV will provoke on electricity demand, steady state operation, market issues, generation schedules and on the volume of carbon emissions. European Commission: Ricardo.

HOVENAARS, E. 2009. *Temporal Resolution in Time Series and Probabilistic Models of Renewable Power Systems.* Master of Applied Science, Queen's University.

MILBORROW, D. & GONZALEZ, S. 2003. The Carbon Trust & DTI Renewables Network Impact Study Annex 4: Intermittency Literature Survey & Roadmap. Brighton, UK: Mott MacDonald.

NATIONALGRID. 2011. *2011 National Electrical Transmission System (NETS) Seven Year Statement* [Online]. National Grid. Available: http://www.nationalgrid.com/uk/Electricity/SYS/current/ [Accessed 2012 June].

NATIONALGRID 2013. Electricity Ten Year Statement 2012 - Appendix A1: System Maps.

NISSAN. 2014. *Nissan Leaf brochure - specs* [Online]. Available: http://www.nissanusa.com/electric-cars/leaf/versions-specs/ [Accessed September 2014].

ONS. 2012. *2011 Census, Population and Household Estimates for England and Wales* [Online]. Office for National Statistics. Available: http://www.ons.gov.uk/ons/publications/re-reference-tables.html?edition=tcm%3A77-257414 [Accessed March 2013].

PANASONIC 2013. Aquarea air/water heat pump: design handbook for split and compact systems. Bracknell.

RADOV, D., KLEVNAS, P., LINDOVSKA, M., ABU-EBID, M., BARKER, N., STAMBAUGH, J. & FLETCHER, K. 2010. Decarbonising Heat: Low-carbon heat scenarios for the 2020s. London: NERA Economic Consulting & AEA.

STERLING, M. J. H., KENNEDY, M., LOUGHHEAD, J., WINFIELD, M., LLOYD, S., DAVIES, P., LUFF, T. & GRIEW, S. 2012. Electricity Transmission Costing Study. Parsons Brinckerhoff.