UNIVERSITY OF BIRMINGHAM

NET ZERO - KEEPING THE ENERGY SYSTEM BALANCED

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NET ZERO - KEEPING THE ENERGY SYSTEM BALANCED: 1.0.0

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1 Executive Summary

- One of the biggest impacts of Net Zero will be the need to find alternatives to the (unabated) use of fossil fuels with their low cost, large capacity and long duration storage options, which still provide nearly all the flexibility and resilience that balance Great Britain's energy systems.
- The heavy lifting in balancing Great Britain's electricity and heat sectors is still done by natural gas, contributing up to 3-4 TWh towards daily balancing, and over 100 TWh between seasons and years.
- This new research simulates future imbalance in a 'pure' renewable electricity system solely using various ratios of wind and solar generation, scaled to meet annual electricity demand. Imbalance calculations, including simulation of the consequences of heat electrification, are derived using matched historical demand and generation data for each day in the period 2015 to 2019, rather than using generation values derived indirectly from meteorology.
- The results show:
  - Future orders of magnitude of system imbalance for heat and electricity are similar to todays, but no longer with ready access to fossil fuel storage to manage them.
  - Electrifying heat would transfer significant extra imbalance into the electricity system, doubling or trebling the scale of daily and cumulative levels, depending on the electric heat technology used.
  - The 'optimum' mix of wind and solar for minimising electricity imbalance differs according to both the applicable timescale and to how, and how much heat is electrified.
- Regarding **daily** imbalance patterns:
  - Electricity system deficit (and surplus) can approach 'worst-case scenario' levels when, over a period of a day (or more), lowest generation coincides with highest demand (and *vice versa*).
  - The capacity credit (the level of conventional generation capacity that can be replaced with renewable generation without reducing system reliability) can drop as low as 5%, depending on the electricity/heat and wind/solar ratios.
- Regarding **cumulative** imbalance patterns:
  - For **electricity** consumption over longer timescales (beyond intra-day), a wind/solar mix containing up to 15-20% solar (by energy) can, despite its high inherent variability, show some positive correlation to demand. This results in a cumulative seasonal system imbalance that is close to, or slightly less than the imbalance resulting from demand patterns alone.
  - When **heat** is added to electricity consumption over these longer timescales, the availability of power from renewable generation mixes is more strongly correlated with the resultant combined demand. This positive correlation reduces system balancing requirements by an average of a third below the level attributable to demand imbalance on its own.
  - Solar generation is partially **correlated to electricity** demand and, over longer timescales, an 80:20 wind:solar mix can halve the system imbalance seen with no solar. However, in contrast, solar output is seasonally **anti-correlated to heat.** Any level of solar in the heat scenarios actually reduces the positive impacts attributable to wind on the cumulative system imbalance. A 20% solar component almost doubles the cumulative system imbalance compared to a mix containing none, so completely eliminating solar enables the availability of electricity to better match **heat** demand.
  - Although it could improve the system capacity credit, inflexible baseload generation, like UK nuclear, does not reduce the order of magnitude of the system imbalance nor does it change the patterns which, by definition, always just mirror those of demand variations.
- Gas infrastructure is already in place and current balancing costs are predominantly included in the price of fuel. Balancing and associated infrastructure costs are not included in the levelised or wholesale costs of electricity from solar or wind which are extensively used in economic system assessments.
- What looks like an optimal energy mix based solely on levelised costs of energy production could look very different to one based on minimising total system cost. For example, replacing the current daily gas balancing capability of up to 3-4 TWh with batteries would cost over £1 trillion, based on recent actual/proposed installation costs of large 'grid-scale' projects in Australia and the UK.

2 Introduction

Running the energy system can be like managing money - supply and demand vary as do income and expenditure and for both it takes a conscious effort to 'balance the books'. Coping with the ever-changing circumstances requires flexibility and resilience.

With money, this can be achieved by increasing and reducing consumption to match changes in income but, more commonly, by having good banking facilities for deposits and withdrawals, somewhere to safeguard surplus funds until they are needed to meet commitments, and affordable loan facilities to bridge deficits during periods of no or low income. Ensuring the availability of sufficient working capital is key to avoiding the cash-flow problems which are one of the most common reasons for otherwise successful businesses to fail. Households and businesses that wish to be financially resilient to unforeseen changes or shocks also build up reserves that can be called upon in difficult times.

Likewise with energy systems - there is a need to 'balance the books' while still satisfying the fundamental requirement to deliver energy when and where users need it. Being resilient to shocks is also important for the energy system and its wider role in supporting society, so as well as having enough flexibility to balance the normal swings in demand and production, adequate resilience cover can help deal with the unexpected.

Since the industrial revolution, fossil fuels like coal, oil and gas have been energy's 'working capital' and represent the mainstay of system flexibility and resilience in Great Britain (GB)[A]. Even now, in 2021, it is still liquid fossil fuels that overwhelmingly provide the buffers of energy in the transport sector, while natural gas delivers the main balancing capability for the electricity and heating sectors.

It is worth emphasising that fossil fuels themselves are energy stores and carriers, not energy sources. They have long provided cheap, almost free energy storage at huge scale to balance across timeframes ranging from sub-second to seasonal, multi-year and beyond. Such 'storage' actually encompasses a broad range of supply side reserves and infrastructure that can be mobilised to serve the needs of consumers.

One of the biggest impacts of Net Zero will be the need to find alternatives to the (unabated) use of fossil fuels with their low cost, large capacity and long duration storage options, which currently provide nearly all the flexibility and resilience that balance GB's energy systems.

A critical element of energy planning for the evolving Net Zero system should be to understand the full technical and economic challenges as well as the wider social impacts of suggested alternatives. Therefore, proposals for GB's future energy system should be able to demonstrate clearly not only how average energy and capacity requirements can be met, but also how, and at what cost, the inherent imbalances between supply and demand will be managed over all scales and timescales. They should also consider how energy will be transported along supply chains and networks to where it is needed, if and when existing fossil fuel pipelines, ships and tankers no longer can.

We will only achieve the right answers for the design of the Net Zero energy system if we ask all the necessary questions. If we focus on in-day balancing of a little energy, locally, there are a number of good options, including batteries. However, we must also ask how truly 'grid scale' energy can be balanced, system-wide, nationally or internationally, and over prolonged timescales. There are currently no easy answers to this, so all the more reason to ensure the questions are asked and satisfactorily answered.

This paper seeks to help frame the necessary questions and the assessment of the answers by demonstrating the orders of magnitude of balancing services currently involved in the electricity and heat sectors, and how these may evolve in potential future scenarios. It starts with analysis of the current role of natural gas in providing flexibility and resilience in GB, then uses new datasets and calculations to simulate patterns of future electricity and heat demand as well as to illustrate how these could be met by 'pure' renewable electricity, exclusively from wind and solar. The paper aims to highlight data and simulation tools to aid others with whole system design and analysis, not to prefer or select any particular solutions.

[A] In this paper we consider the GB energy system (England, Wales and Scotland). Northern Ireland has separate responsibility for energy and a 'single market' for electricity operated together with the Republic of Ireland.

3 Natural gas' role in flexibility and resilience for heat and electricity

Various components of the gas system combine to provide the flexibility and resilience needed to balance supply and demand across the year. Figure 1a shows the largest recorded daily contribution made by each of the elements from 2015 to 2019 – a potential total of 6,734 GWh. In comparison, the load duration curve in Figure 1b shows the actual daily range of outputs from 2018 ranked from the daily maximum on the left, extending across to the minimum on the right. In 2018 the daily range was from 4,604 to 1,444 GWh.

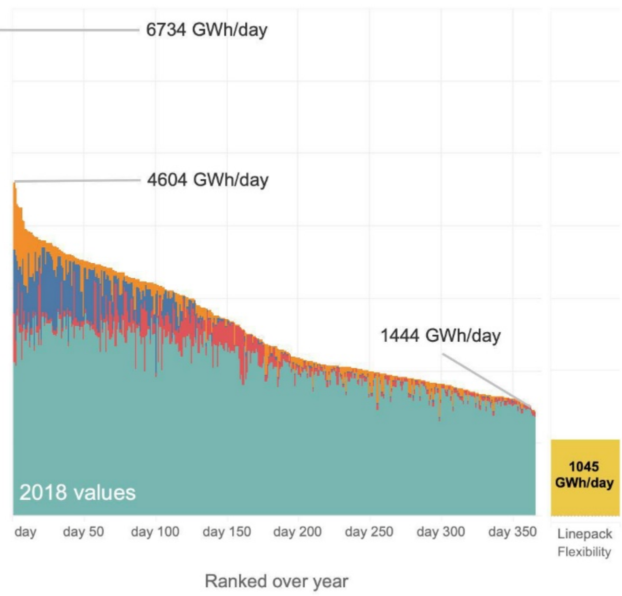


Figure 1a Daily gas storage capacities in GB **Figure 1b** Load-duration curve for gas supply in 2018

Linepack flexibility is also shown alongside the load duration curve on the right at up to 1,045 GWh/day. This and the other categories are further described and quantified[1] as follows:

- **North Sea Infrastructure (supply ranges from 1.7 - 3.0 TWh/day)** - access to the gas 'stored' in the North Sea, including the UK Continental Shelf (UKCS) which can be flexed through the production process to meet different daily and seasonal needs. The daily availability is primarily limited by extraction and transport capabilities. Unlike the other elements this does not reduce to zero.
- **International LNG supplies (up to 1.5 TWh/day)** – alongside supply from LNG storage tanks, maximum GB daily availability is determined by the onshore regasification and unloading capacity, as well as by commercial contractual arrangements and international competition.
- **Interconnector/international pipeline supplies (up to 1.2 TWh/day)** – maximum daily availability is determined by the physical capacity of the pipelines, as well as by the commercial contractual arrangements, international competition and, in some instances, Public Service Obligations or politics.
- **Physical storage (up to 1.1 TWh/day) -** consists of salt caverns and disused gas fields – daily maximum availability is determined by the associated extraction and transport capabilities.
- **Linepack flexibility (up to 1.0 TWh/day) -** within the gas pipelines, the pressure can be adjusted between the minimum necessary to keep the system operating and the maximum allowable for safe operation – this is described as linepack. Linepack flexibility represents the fraction of total linepack which is utilised to manage flexibility. Pressure in the transmission and distribution networks is increased (e.g. overnight) and then, together with the direct transport of gas through the pipes, released to satisfy the varying requirements of users over the day(s). Although only part of the total amount of gas in the network, it still represents a significant quantum. Under current operational practices linepack flexibility over a day typically represents about 6% (280 GWh) of the total gas in the pipeline but can grow to 15% (690 GWh) of this on more extreme days.

Reducing linepack pressure (conceptually equivalent to discharging gas storage) can boost the supply of natural gas above what is being transported along the network for some time and has reached as much as 113 GWh over one hour and 251 GWh over a 3-hour period[2]; corresponding to 91 GWh over the first hour, 92 GWh over the second and 68 GWh over the third.

Linepack flexibility currently plays a crucial role in the electricity and heat sectors by providing a large proportion of within-day and overnight flexibility. It is used to help manage the extremely fast ramp rates, e.g. through the morning as multiple heating and hot water systems are switched on within a few hours of each other, or as gas-fired power stations ramp up to support short-term increases in electricity demand. Linepack flexibility therefore acts as an enormous buffer which avoids the need for the up-stream gas production and supply chain to exactly mirror demand patterns.

The greatest change in combined transmission and distribution linepack flexibility values happened before and during the Beast from the East (Figure 2) between the maximum at 16:00 on 24 Feb. 2018 (4,886 GWh) and minimum at 21:00 on 1 Mar. 2018 (3,841 GWh). The difference between the maximum and minimum was 1,045 GWh and demonstrates the potential levels of power and energy in linepack flexibility.

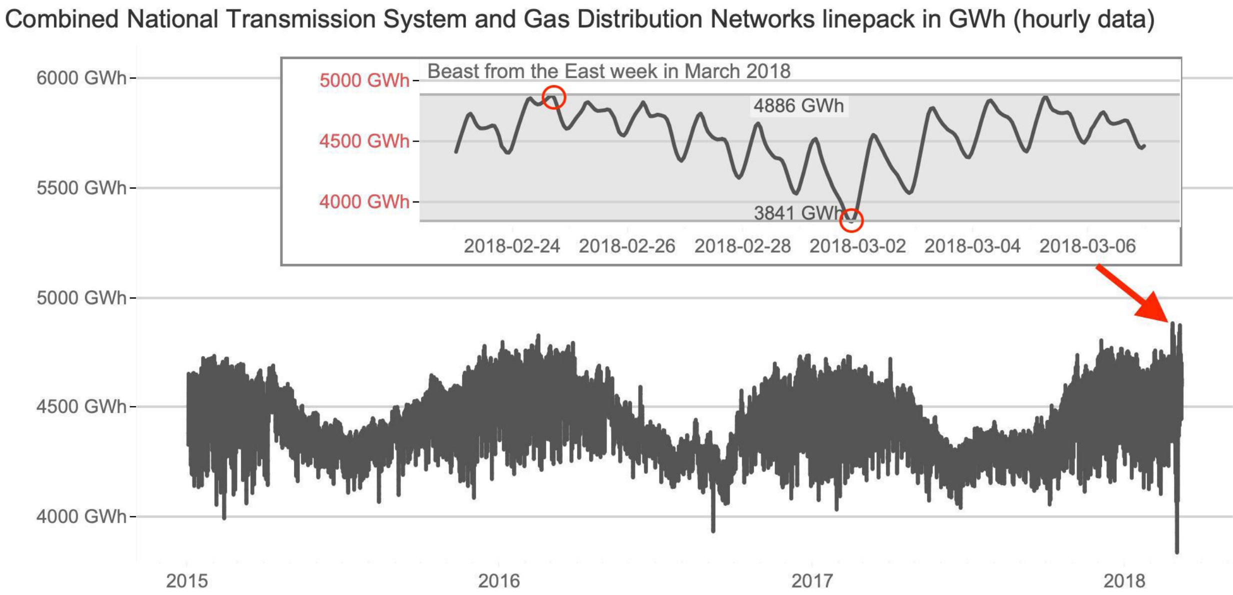


Figure 2 Combined linepack from January 2015 to March 2018; inset are the 10 days from 26 February to 7 March which included the Beast from the East.

3.1 Natural gas infrastructure

Linepack flexibility together with salt caverns and LNG (storage tanks and regasification) have provided a combined usable daily physical delivery capacity up to about 3,500 GWh. This helps the gas system, either directly in the heating sector, or indirectly by fuelling OCGT and CCGT generators in the electricity system, to flex sufficiently to meet the system balancing requirements over a day. The capacity from the North Sea, interconnectors and the wider LNG supply chain can also flex supply over a day, but more importantly, they allow the system to balance over longer seasonal timescales, e.g. by increasing supply in the winter.

Crucially, this flexibility has also been provided at an affordable cost. Significant gas infrastructure is already in place so potentially finding ways to augment and repurpose it at lower cost and with less disruption than could be associated with alternative options, is proving a strong, albeit sometimes controversial incentive to pursue low/zero-carbon gas options, like hydrogen, and/or for the continued transport and storage of natural gas for future use with Carbon Capture Utilisation and Storage applications.

The ability to source gas from international supply chains and to transport it across the world at relatively low cost has allowed access to gas from diverse global sources and has significantly reduced the price differentials between regions. International supply chains have also improved resilience and allowed GB to move from being a net exporter of gas to a net importer since 2003[3].

This comprehensive system has provided essential system services as well as energy. Future solutions must also be able to meet the base energy needs and to balance the electricity and heat sectors, e.g. by storing and conveying energy in large enough volumes to be available where, when, and for as long as needed. Deciding on the way forward is no simple task and must be well planned – it will not happen by default[4].

4 Balancing supply and demand

In order to investigate the scale of flexibility required to balance supply and demand we analysed on a daily and cumulative basis:

- **demand** imbalance patterns
- potential future **generation** imbalance patterns
- how these combine to create an overall **system** imbalance pattern.

More detailed methodology and data sources are described in the Annex (Section 7) with the main results discussed in the body of the paper.

4.1 Demand patterns

Detailed historic data representing electricity and heat consumption (derived from gas) has been used to illustrate the demand patterns which can vary significantly throughout the day and seasons, as well as between years. 2018 was an interesting year for heat consumption because of the 'Beast from the East' in early March. Figure 3 shows the patterns for electricity and heat using daily data.

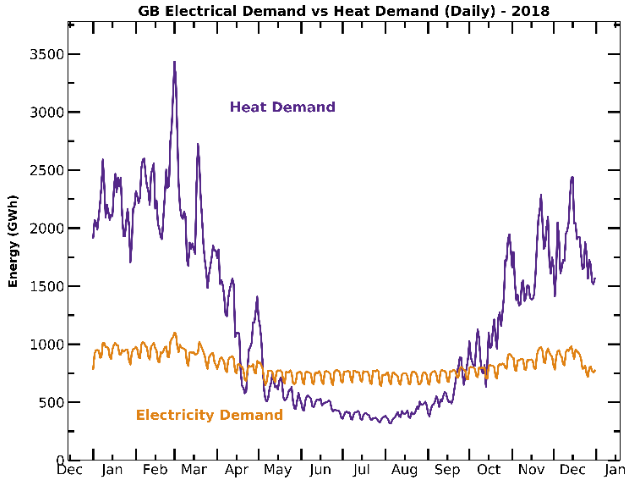


Figure 3 2018 daily electricity and heat demand

To further characterise and quantify these patterns of imbalance, the average 2018 daily demand (from Figure 3) was calculated for combined electricity and heat. Each day was then plotted as the deviation from this average. This is shown in Figure 4 with the days plotted a) chronologically on the left-hand chart and b) ranked from greatest above-average to the greatest below-average on the right-hand chart.

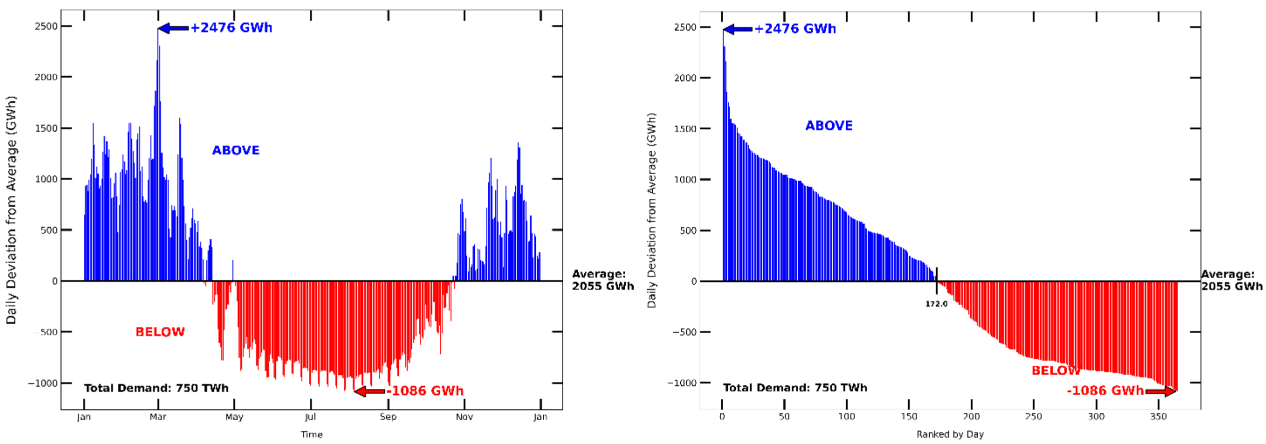


Figure 4 Electricity and heat demand – deviation from average **a)** chronological and **b)** ranked

Over the year, daily demand deviated between 4,531 GWh and 969 GWh, i.e. extremes of +2,476 GWh and -1,086 GWh from the average of 2,055 GWh, equivalent to +120% and -53%.

Over the period 2015-2019 the range seen in the other years extended only from +88% to -56%. The high-demand extremes were well below 2018 levels showing the scale of the impact of the Beast from the East on **heat** system balancing requirements. (NB Figure 3 shows much less impact on **electricity** demand.)

In the current system, the supply to heat and electricity is flexed (predominantly through natural gas) to balance demand, so these overall orders of magnitude are a good reflection of the daily balancing provided by natural gas to these sectors. The efficiency of heat production in buildings with modern gas boilers is 85-95% and with simple electric radiators[B] it is 95% or more, so this simulation is also roughly equivalent to the theoretical (albeit extreme) scenario for future demand patterns if all heat in buildings were provided by electric radiators. We explore later the impact of using air source heat pumps for heat production.

4.2 Electricity generation patterns

In the past, dispatchable generation (oil, coal and gas) was simply ramped up and down to meet electricity demand at any point in time. However, the system balancing needs are also affected by the output of inflexible (e.g. nuclear and most CHP) and, increasingly, intermittent/variable (e.g. wind and solar) generation.

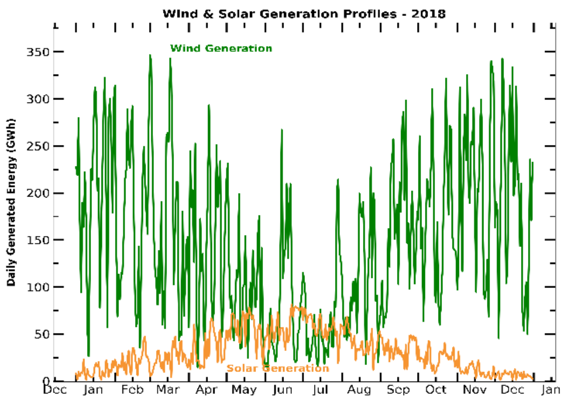
With the ever-growing deployment of low-carbon generation, the characteristics and system impact of imbalance driven by them will evolve further:

- If generation were only provided by inflexible, baseload plant running continuously with a fixed output level, the resultant system imbalance would still just mirror that of demand in both scale and pattern[5].
- If generation were composed only of variable and intermittent technologies, there are two extreme scenarios between which the resultant imbalance could lie:
  - if generation and demand patterns were completely correlated, there would be no imbalance at all.
  - if generation output were anti-correlated with demand, the aggregate imbalance could at times reach the 'worst-case scenario', i.e. minimum generation at a time of maximum demand and *vice versa*.

Since nearly all Net Zero scenarios for GB electricity foresee the predominant deployment of wind and solar, the following sections illustrate their output and imbalance characteristics when aggregated together in a range of ratios. Combining these with various demand scenarios gives an indication of the orders of magnitude of potential future system imbalance.

4.3 Wind and solar generation

Figure 5a shows typical daily generation profiles of solar and **wind**[6], using reported data from 2018. The Figure illustrates output variability/intermittency and also shows the very different seasonal patterns of the two, i.e. wind output is higher in winter and lower in summer, whereas solar has its highest output in summer and generates much less in winter. Previous research has suggested a suitable combination of wind and solar production for matching GB **electricity** demand is reached with an annual wind energy component between 80% and 85%, with solar between 20% and 15%[7]. Figure 5b illustrates how the electricity balancing need (shown here as the theoretical storage buffering requirement over the year) reduces to a minimum as the wind share increases, before rising again after around 80-85%[8].



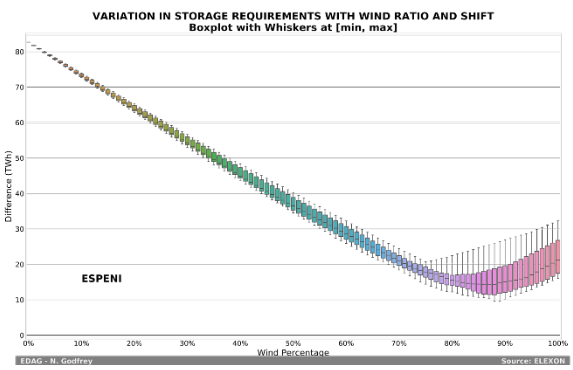


Figure 5a Wind and solar electricity production **Figure 5b** Wind and solar ratios – combined impact

[B] Radiators is used throughout this paper to describe direct resistive heating

4.4 System imbalance patterns

For Figure 4 in Section 4.1, levels of demand imbalance were characterised by measuring the daily deviation from average. A similar approach was adopted for generation imbalance. Based on recorded data for generation output from 2018, a renewable system using just wind and solar in an 85:15 ratio was simulated. The observed generation data was normalised to account for the capacity additions during the year, then scaled so the output meets demand (electricity and heat). Detail of methodology is described in Section 7.

Figure 6 shows the daily generation deviation from average and the installed capacities of wind and solar. Figure 7 shows demand deviation from average as well as total annual demand. Figure 8 represents the system imbalance as a daily surplus or deficit resulting from the difference between each day's generation and the same day's demand. The largest system deficit occurs when the extremes of below-average generation and above-average demand coincide (and *vice versa*). The system will be most balanced at times of correlated generation and demand, regardless of whether this is at, above or below average levels.

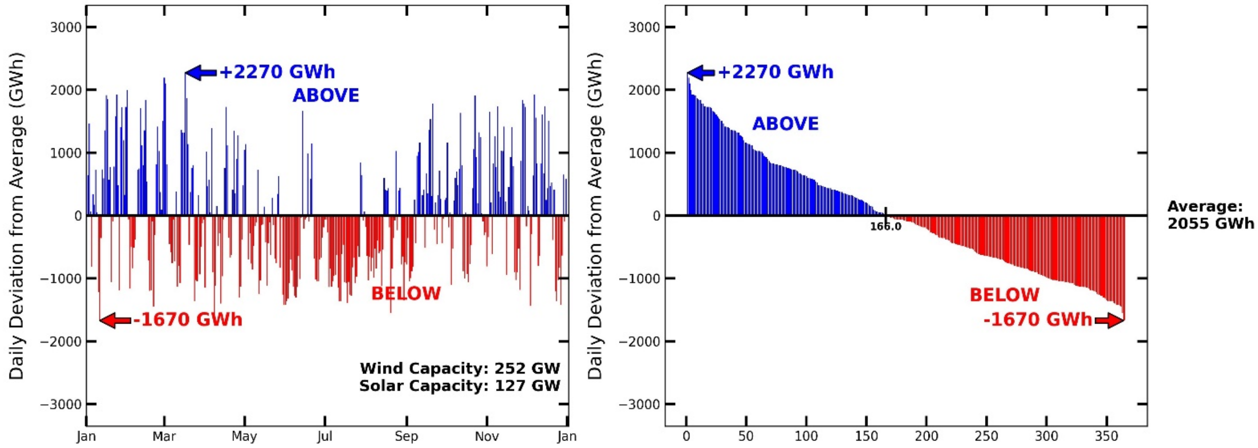


Figure 6 Daily **generation** deviation from average, a) chronological (left) and b) ranked (right)

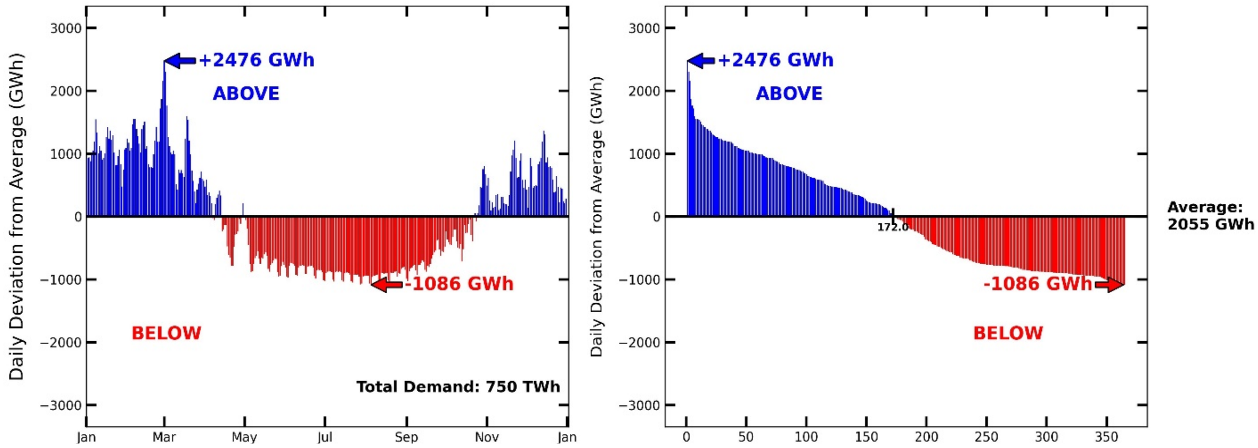


Figure 7 Daily **demand** deviation from average, a) chronological (left) and b) ranked (right)

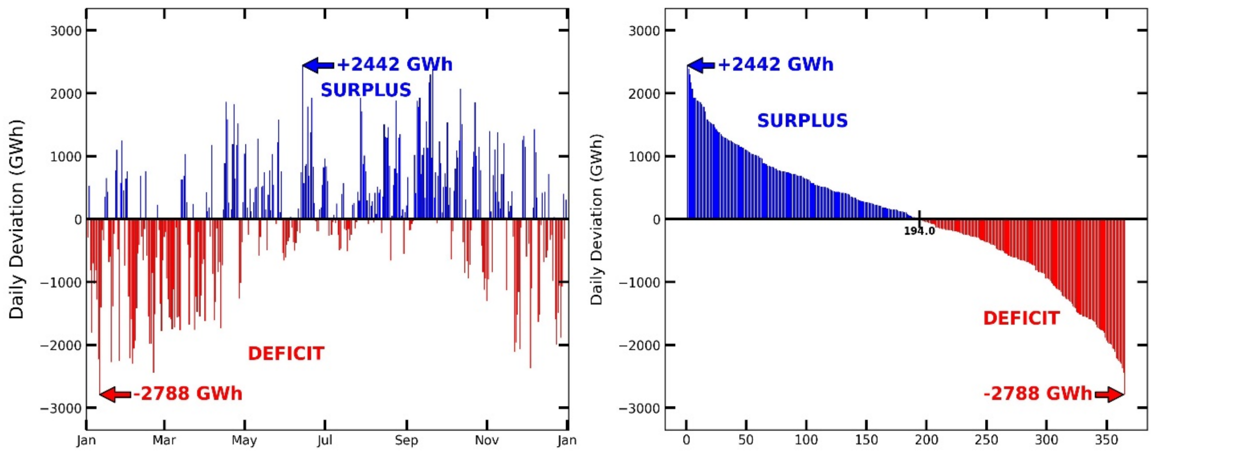


Figure 8 Daily **system** surplus and deficit, a) chronological (left) and b) ranked (right)

The same methodology was then used to examine how various demand combinations (based on 2018) could be met with a range of wind:solar ratios from 80:20 to 100:0 (in 5% increments). The daily system imbalance was calculated by subtracting each day's measured demand from the normalised and scaled daily generation for the same day. The three demand scenarios were:

a. Electricity only
b. Electricity plus heat based on electrification with radiators (as previously simulated above)
c. Electricity plus heat based on air source heat pumps (ASHP) using a combined coefficient of performance (CoP)[C] for heating and hot water of 3 from April to November, and 2 between December and March[9].

Table 1 below summarises the range of results for the extremes of deviation from average in 2018:

Table 1 (2018)	Average demand	Range of extremes of daily system imbalance compared to average daily demand (for 80-100% wind)			
Scenario	(GWh)	Surplus (GWh)	Surplus (%)	Deficit (GWh)	Deficit (%)
a	818	+735 to +1,028	+90 to +126	-819 to - 823	-100 to -101
b	2,055	+2,439 to +2,630	+119 to +128	-2,786 to -2,797	-136
c	1,386	+1,571 to +1,578	+113 to +114	-1,812 to -1,820	-131

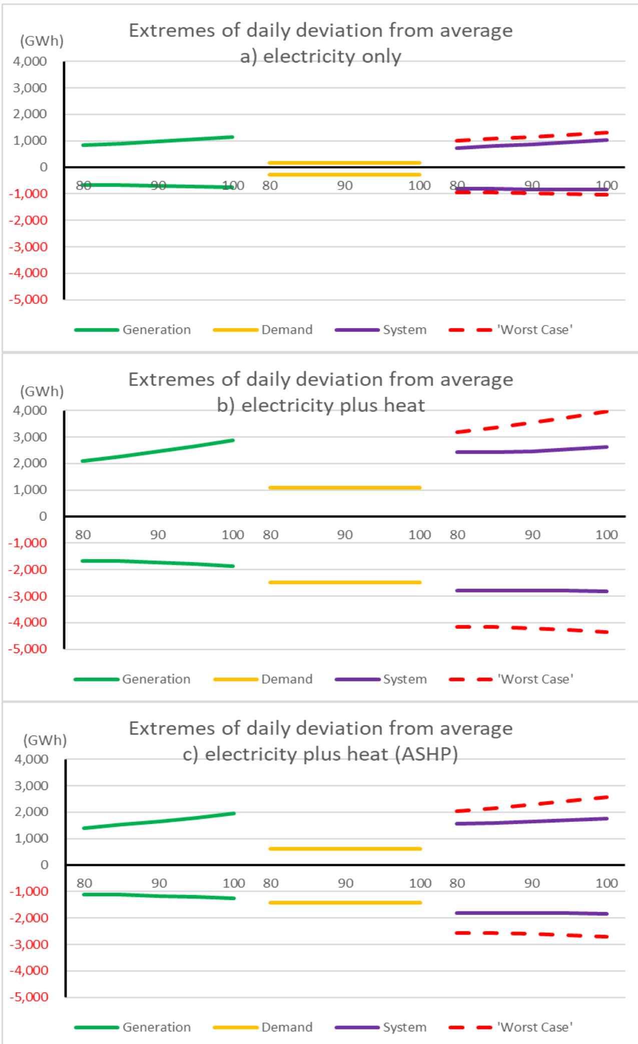


Figure 9 – daily deviations from average for a) electricity, b) plus radiator heat, c) plus ASHP heat

Figures 9 a, b and c show for the respective scenarios the extremes of daily deviation from average for **generation** and **demand** in 2018. They also show the extremes of surplus and deficit for the **system** in relation to the potential '**worst-case scenarios**' which would arise if a day of minimum production coincided with a day of maximum demand or *vice versa.* (NB the values for the 85% wind scenario are equivalent to those shown previously in Figures 6, 7 and 8).

In 2018 (the year shown in Figure 9) the extremes of **system** deficit reached 87% of the '**worst-case scenario**' while **system** surplus reached 73%.

The methodology was also extended to all years from 2015-2019 where the extremes of **system** deficit reached 64-99% of the '**worst-case scenario**' while **system** surplus reached 61-91%.

Changing the ratio of wind and solar from 80:20 to 100:0 did not have a major impact on the daily system surpluses and deficits.

Another indicator of system adequacy is the capacity credit. This is the the level of conventional generation capacity that can be replaced with renewable generation without reducing system reliability. In 2016, a year of relatively low wind output, this fell at times to between 5% and 13% (depending on electricity/heat scenario and wind:solar mix).

[C] CoP is a measure of the efficiency with which a heat pump extracts heat from its surroundings. For example, a CoP of 3 means that if 1 kWh of energy is used to run the pump, 3 kWh of usable heat is produced.

NB in 2016 the 'worst-case' daily-deficit scenario was all but reached. For example, with electricity only:

- On 20 January, the maximum daily-average demand for that year was recorded at 1,038 GWh, equivalent to 43.3 GW of theoretical firm capacity over the day.
- On 19 January, the minimum daily average combined wind and solar (85:15) generation output for that year was recorded at 82 GWh, equivalent to a theoretical firm capacity of 3.5 GW over the day.
- Together this meant a potential 'worst-case' deficit for 2016 of 39.5 GW (43.3-3.5 GW).
- On 20 January, the biggest actual daily average system deficit for that year was recorded at 955 GWh, equivalent to 39.2 GW over the day i.e., 99.2% of the worst-case scenario (39.2/39.5*100%).
- The capacity credit for electricity over 19 and 20 January was therefore 9% (3.5/43.3*100%))

4.5 Cumulative impacts

Over the course of a year, there may be many successive days of above- and below-average generation and/or demand which lead to a cumulative impact on system imbalance. Most significantly, seasonal differences in heat demand lead to large cumulative differences between summer and winter. The upper graphs in Figure 10 reproduce the 2018 chronological daily imbalance patterns from Figures 6, 7 and 8, and show how these patterns translate into the respective cumulative imbalances for **generation**, **demand** and the **system** in the lower graphs. (Blue days in the upper graphs increase the values shown in the lower ones, whereas red days decrease them). This resultant cumulative **system** balancing requirement is an indicative measure of the capacity of storage that would be needed to both absorb all surplus and service any deficit over the year.

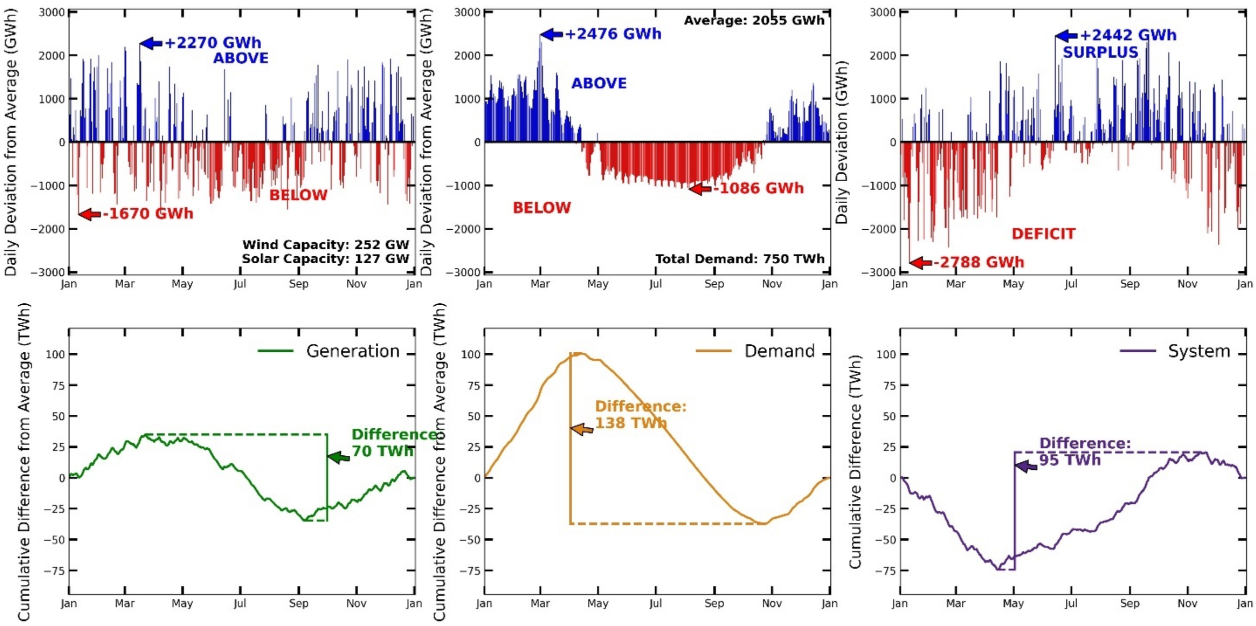


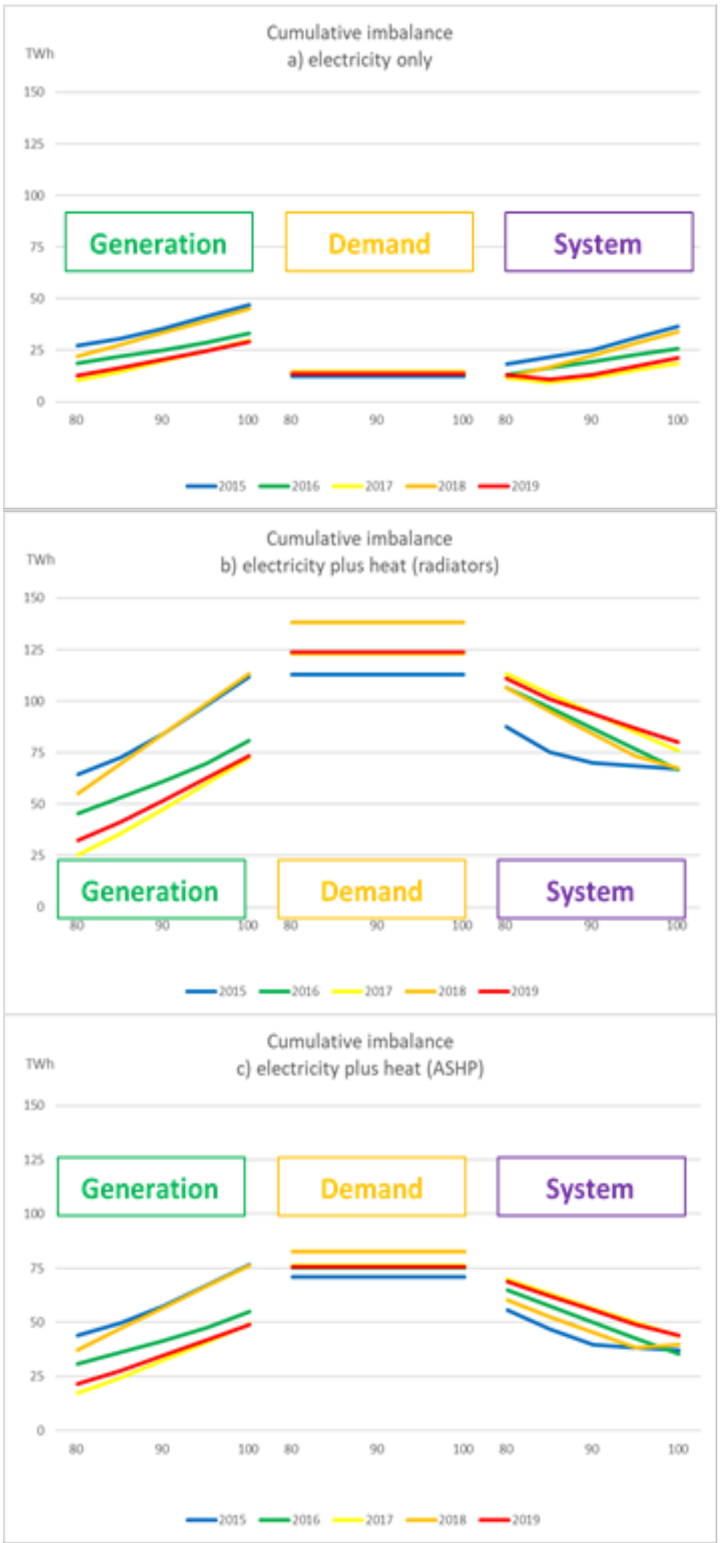
Figure 10 Daily + cumulative **generation**, **demand** and **system** imbalance for electricity and heat (radiators)

Across the year, **demand** imbalance of 138 TWh (measured as the difference between minimum and maximum values reached) is almost twice that of **generation** at 70 TWh. However, there appears to be a correlation between generation and demand patterns, since not only is the **system** imbalance of 95 TWh well below the 'worst-case scenario levels' that could have arisen (as described earlier for daily imbalance), but actually reduced below that of demand on its own.

A series of further simulations was carried out, again using the previous three demand scenarios. The wind proportion was varied from 80% to 100% (in 5% increments) based on the reported generation data from the years 2015-2019 (normalised and scaled as before). These years demonstrated some interesting variations in their generation and demand characteristics:

- 2015 had relatively high and 2016 relatively low wind output[10]
- 2018 included high demand during the Beast from the East
- 2019 had very few capacity additions of wind and solar throughout the year, reducing any impact of normalising the measured data.

The results of the simulations are summarised in Figures 11 a), b) and c).



- For electricity alone, cumulative **generation** imbalance is nearly always greater than that of **demand**. When heat is also considered, this is reversed.
- For **electricity** alone, increasing the wind proportion above 80% increases the **system** imbalance. On average, the cumulative **system** imbalance with 100% wind is double the level reached at 80%.
- In all the **heat** scenarios, the cumulative **system** imbalance was not only much less than in the 'worst-case scenario' where **demand** and **generation** imbalances might have aggregated together, but also less than the **demand** variation alone. This indicates that, over each of the years, there was a positive correlation between the variation in generation and variation in demand. The cumulative **system** imbalance is hence also less than it would be with inflexible baseload generation, like nuclear, where it would always mirror **demand** imbalance in pattern and scale.
- For the **heat** scenarios, raising the wind ratio above 80% increases the imbalance of the **generation** output. However, as the resulting variability appears to better match the **demand** pattern, the cumulative **system** imbalance reduces as solar is eliminated.
- For both scenarios that include **heat**, increasing the wind ratio right up to 100% reduces the cumulative **system** imbalance by a third compared to an 80% share.
- Solar output is anti-correlated to heat and any level in the mix adversely impacts on the cumulative **system** imbalance, even when electricity demand is also included.
- Variations of ±33% from median were seen between the **system** imbalances across the years for electricity. For electricity and heat the variation was ±13%.

Figure 11 – cumulative imbalance from **a)** electricity, **b)** plus radiator heat, **c)** plus ASHP heat

4.6 Inter-year imbalance

The results considered above are for single years in isolation, but an imbalance can also accumulate across many years[11]. The upper graphs in Figure 12 show the daily imbalances across the five-year period 2015-2019 for electricity with heat from radiators (based on an 85:15 wind:solar ratio). The lower graphs show how these patterns then translate into the respective cumulative imbalances for **generation**, **demand** and the **system**.

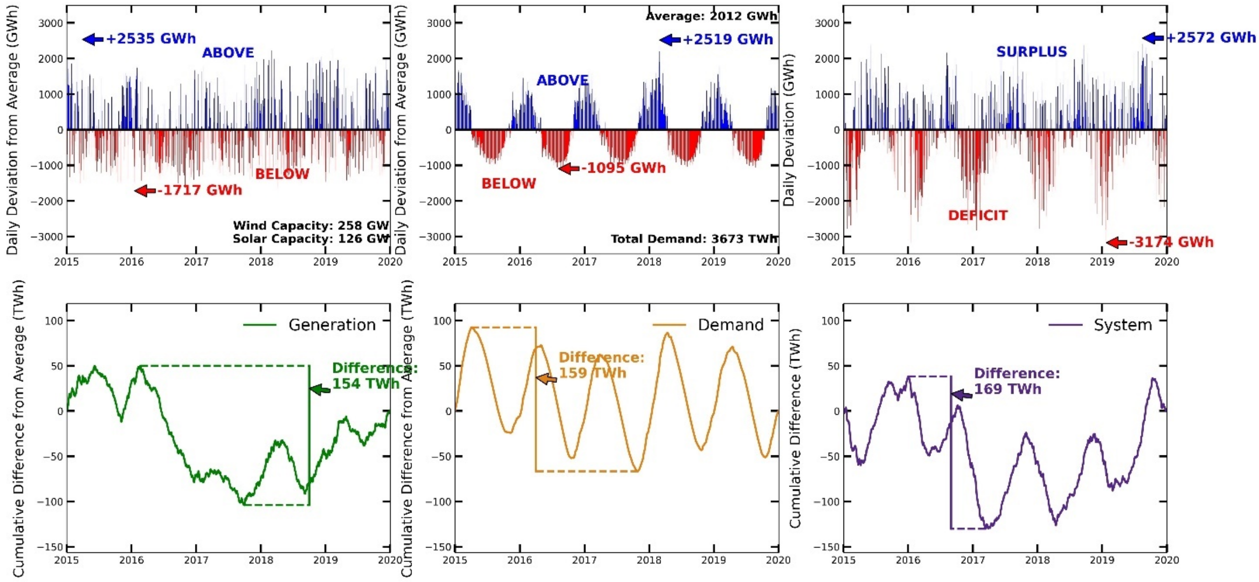


Figure 12 – Daily (upper) + 5yr cumulative (lower) imbalance for **generation**, **demand** and **system**

Table 2 below summarises the cumulative impact for all scenarios.

Scenario	Range of single-year system imbalances	5-year cumulative system imbalance	Increase
a) Electricity only	9-22 TWh	57 TWh	160-530%
b) Electricity + radiator heat	75-104 TWh	169 TWh	60-125%
c) Electricity + ASHP heat	47-63 TWh	113 TWh	80-140%

5 Comparing balancing options

A whole system view should be taken to determine which option or options to deploy to manage future imbalance. Solutions must be found for all timescales, but our results show the ‘optimum’ solution for short timescales is not always the same as for longer ones. Similarly, the ‘optimum’ for the electricity sector alone is not the same as in a system that also considers heat demand with its highly seasonal characteristics.

Any solution should be capable of meeting the orders of magnitude of imbalance both in terms of energy and duration. Our results confirm that, as with today’s system, one composed only of wind and solar generation also requires ‘grid scale’ balancing of up to 3 TWh on a daily basis, and tens or hundreds of TWh are needed for seasonal and multi-year timescales.

We suggest a simple ‘target’ to quickly visualise how potential option combinations stack up against these requirements. We have shown examples of current UK storage capabilities in Figure 13. These estimates illustrate the orders of magnitude difference and how these are disguised by a log scale which is often used to show all options together. (NB not all combinations of capacity and duration can be achieved together.)

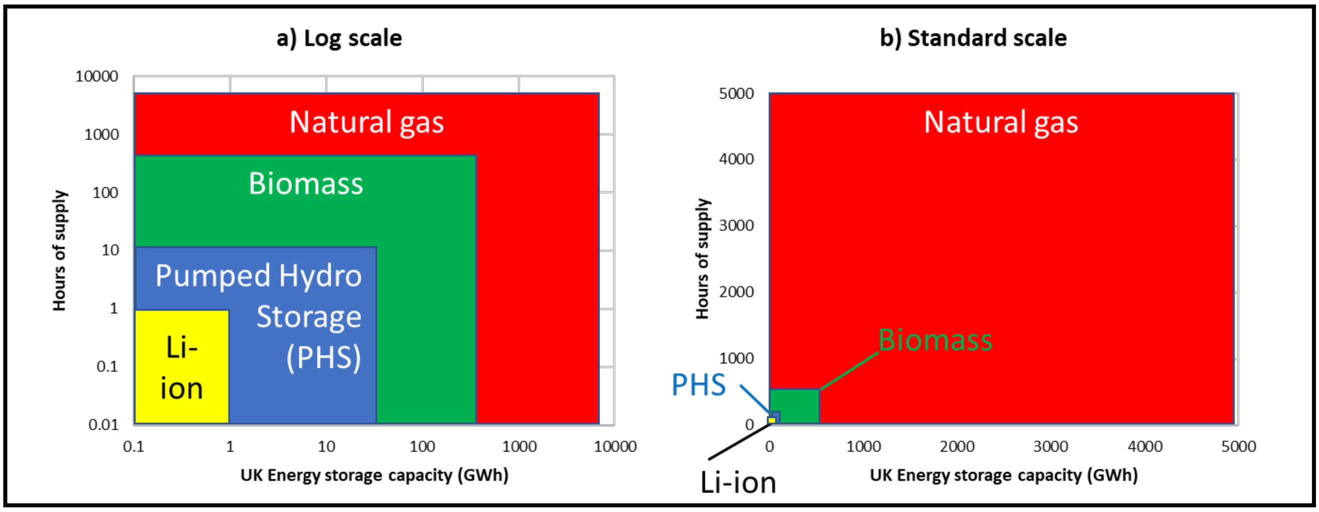


Figure 13 Capacity and duration comparison **a)** log scale, **b)** standard scale

5.1 Comparing balancing options – cost

Whatever solutions are chosen they must also be affordable. The total system cost must be considered, i.e not just the simple, ‘levelised’ cost of producing energy but also that of meeting demand for energy throughout the system in a reliable way across and between days, seasons and years. A significant proportion of this cost is likely to be attributable not only to any energy efficiency losses but also to the cost of storing and transporting the energy, including the expense of building and maintaining the infrastructure. What looks like an optimal energy mix based solely on levelised costs of energy production could look very different to one based on minimising total system cost.

The wholesale price of natural gas includes nearly all[D] of the balancing costs relating to storage and infrastructure. These may be unnaturally low as many older assets will have been deprecitated, but if the costs of operating and maintaining the system can be kept down, it could be seen as an argument in favour of continuing to use it. Since neither the wholesale nor levelized costs of electricity from wind and solar include any storage cost component, the future system balancing costs will be additional and potentially significant enough to question economic feasibility.

Balancing tens and even hundreds of TWh across seasonal and multi-year timescales is a big technical and economic challenge for systems with significant demand variability and with high levels of variable or inflexible generation. Thermo-mechanical options like pumped storage and batteries work well for smaller-scale, shorter duration applications[12]. However, these are optimistically also being put forward as a solution for seasonal, grid-scale applications, but they fall several orders of magnitude short in terms of both capacity and duration and are therefore ill-suited to these applications. Costs are also orders of magnitude

[D] The costs of linepack are separately included in various network charges.

awry, e.g. replacing daily gas storage of 3.5 TWh with batteries would cost over £1 trillion, based on recent actual/proposed installation costs of large 'grid-scale' projects in Australia and the UK [13]. Even just replacing linepack flexibility capabilities with batteries would cost about £400 billion.

It is hard to see how imbalance can be managed without extensive use of low/zero-carbon chemical fuels. Although these may be more expensive than natural gas, even at ten times the storage and transportation cost, such options would still remain orders of magnitude less expensive than batteries and thermo-mechanical alternatives.

6 Results – questions arising

The current electricity system is sized to meet peak electricity demand. System security is maintained with dispatchable generation e.g. CCGT, which has a capacity credit of nearly 100%, i.e. it can be ramped up quickly and relied upon to provide near full capacity at times of maximum demand. The capacity that is not needed at other times is simply ramped down or switched off, saving on fuel – the dominant cost.

Our daily-imbalance results for a high-renewables system indicate that multiple days of high demand can coincide with days of low wind and solar output (and *vice versa*). This, as well as the scale of the daily and cumulative imbalances, raises questions which will require further research and consideration:

- With a capacity credit that can fall to 5%, could it be practicable or economical to size a predominantly wind and solar system to meet peak demand if, at its extreme, this would require installed capacity of about 20 times the level needed to meet all demand across the year?
- Is there a level of over-capacity that nevertheless reduces system deficit economically, and what would be done with the excess generation on days of system surplus?
- If inflexible baseload generation, like nuclear, were added into the mix to reduce deficits and improve the capacity credit, how could the increased surplus on other days be managed and with what economic impacts?
- What alternative flexible generation could be added to the system to complement wind and solar, and what economic case can be made for such alternatives which may have to deal with up to 95% of peak demand but may only be utilised for a fraction of the time?
- What contribution could demand side measures play beyond lowering the overall scale (but not orders of magnitude) of capacity and energy levels through efficiency gains, or through intra-day, short-term load shifting? Can they play any significant role for the seasonal and inter-year imbalances measured in tens or hundreds of terawatt hours?
- What would be the capacity credit of interconnectors used for import? Could this even be negative at times when other countries' needs are greater and price or political pressures divert supply?
- With relatively flat inter-day but potentially significant seasonal demand patterns (due to lower battery efficiency and increased use of electrical in-car heating in cold weather) what impact would electrification of the transport sector have on inter-day and seasonal imbalance?
- The principles simulated in this paper have been to size the renewable electricity system to meet average demand and complement this with 'ideal' storage capable of balancing the surpluses and deficits. However, could it be advantageous to instead consider the use of renewables to directly produce an alternative vector, e.g. hydrogen, without first generating, transmitting and distributing electricity? Despite disadvantages in efficiency losses, could the system economics be more attractive if this vector could then be stored and transported, like natural gas today, for the flexible generation of electricity for power applications and direct use for heat?

7 Annex – Data sources and methodology

7.1 Generation and demand data – electricity

Great Britain's half-hourly generation data comes from Elexon and National Grid ESO datasets. The method to combine these into the GB demand time-series is detailed in the preprint *Calculating Great Britain's half-hourly electrical demand from publicly available data*[14]*;* in summary, the transmission connected metered generation data are from Elexon and the estimated distributed generation data is from National Grid. Electrical exports are then netted off imports to calculate the Great Britain's half-hourly electrical demand. The half-hourly dataset that is used to aggregate to the daily data can be downloaded from Zenodo[15]. Some space heating and hot water will currently be utilising electricity as the input energy source, and thus will already be included in existing GB electricity demand. We have not attempted to disaggregate the electrical demand for heating and hot water for buildings as a fraction of national electrical demand.

7.2 Supply data – gas

National Grid's daily gas supply data is reported in five separate categories:

- ***Industrial Offtake***: shows no discernible seasonal pattern, so little/no contribution to heat in buildings
- ***Interconnector***
- ***LDZ Offtake***: Local Distribution Zone (LDZ) is the gas delivered to households, smaller industry as well as to public and commercial buildings by the Gas Distribution Network companies. This category includes the vast majority of space heating and hot water in buildings. Power stations that are connected to the distribution system also draw gas supply from this *LDZ Offtake* category.
- ***NTS Power Station***: (National Transmission System) This is an aggregation of demand from power stations that are connected directly to the transmission system.
- ***Storage and LNG.***

The *LDZ Offtake* category can be further disaggregated into *daily metered* and *non-daily metered* gas demand. *Daily metered* represents end users with higher gas demand warranting daily meter readings, whereas *non-daily metered* represents end users with lower demand, historically measured on a monthly or quarterly basis[E].

7.3 Methodology to estimate the fraction of GB gas used for space heating and hot-water

Historically heat demand was roughly estimated by subtracting all other known demand categories from total energy demand. Even though much progress towards better estimates has been made, our analysis aimed to provide a more accurate evaluation of the energy for space heating and hot water that is provided by natural gas. For this, the datasets published by the Department for Business, Energy, and Industrial Strategy (BEIS) in *Energy Trends for Gas* were used alongside National Grid's data [16], mentioned above. The BEIS data in the spreadsheet *Natural Gas Supply and Consumption (ET 4.1 - quarterly)*[17] timeframes uses information collected from suppliers and end users under the categories:

- Electricity Generation (assumed not to include heat for buildings)
- Heat Generation (energy sold as 'heat' for buildings or processes, including CHP and District Heating)
- Energy Industry Use (transmission level process heat - disregarded for these purposes)
- Losses (disregarded for these purposes)
- Iron & Steel (including heat for both processes and buildings)
- Other Industries (including heat for both processes and buildings)
- Domestic (all for heating and hot water in buildings[F])
- Other Final Users (including some heat for buildings).

None of these categories provides a clear estimate of sectoral or total heat and hot water used in buildings, nor does the data make clear how much of the supply to each category has come from transmission or

[E] Smart meters with automated daily readings are conceptually changing the technical basis for these categories, but the historical classification remains.

[F] The 2-3% of gas used for domestic cooking was not considered (https://www.gov.uk/government/statistics/energy-consumption-in-the-uk) distribution. To reconcile the BEIS user data and National Grid supply data, a number of steps were required to assess how much gas in National Grid's *LDZ Offtake* classifications is used for each of the BEIS categories and what proportion should be attributed to heating in buildings:

1. ***Electricity generation*** - the gas usage recorded in BEIS *Electricity Generation* is consistently greater than that from National Grid's *NTS Power Station*. The difference (typically a value of 20-30% of *BEIS Electricity Generation*) was taken to represent the electricity generation that was supplied by gas distribution networks and reported as part of the *LDZ Offtake* category.
2. ***Heat Generation*** - this BEIS category covers the output from CHP and District Heating plants sold specifically as heat. BEIS has also produced draft data for heat delivered by heat networks[18], based on fuel specific data from Heat Metering and Billing Regulations (HMBR) which was collected from 2015 and published in 2018. Following discussions with BEIS, the subset of data for heat produced from gas was taken from Table 4 of this HMBR-based data. The proportional quarterly split of heat production from BEIS Energy Trends[19] was then used to disaggregate this HMBR-based data into quarters and thus establish the amount of heat produced using gas. This heat is currently provided by fossil fuels and will, in future, also need to be zero carbon, whether supplied through heat networks or other routes.
3. ***Industry* (various)** - to separate out the supply to *Industry* coming from the distribution networks, National Grid's daily *Industrial Offtake* (transmission supply) values for each quarter were subtracted from the total of the BEIS values (based on user data for supply from transmission and distribution) for the same quarter in the categories: *Iron & Steel, Other Industries, and Non-Energy Use.* The residual quarterly supply patterns were clearly seasonal (whereas the supply to industry from transmission was not) and indicated that it would be appropriate to attribute some of this to distribution supplied heating in buildings (see '6' below).
4. ***Other Final Users*** **-** this BEIS category, was also found to have a seasonal variation, again indicating that it would be appropriate to allocate some of the gas in that category to heating in buildings.
5. ***Domestic*** – all of this BEIS category was attributed to heating and hot water in buildings.
6. **Fine-tuning the attribution to heat in buildings -** the quarterly values for *Industry* and *Other Final Users* from '3' and '4' above were each first normalised by calculating and plotting the percentage each quarter represented compared to the highest quarterly value across the period in the respective category. The resultant quarterly patterns represented by the percentage values were empirically compared to those of the similarly normalised *Domestic* category.

   Then in an iterative process for each quarter, a constant value was subtracted from each of the respective *Industrial* and *Other Final User* demand values (effectively representing the removal of any 'flat' non-seasonal process heat) – this initially improved the visual correlation of seasonal patterns. When a point was reached at which further subtraction worsened the visual match to the *Domestic* demand pattern over the whole 5-year period analysed, this was taken to be the best estimate for gas supply to these user categories for heating and hot water in buildings from the distribution networks.

   Each so-modified quarterly value was expressed as a percentage of its original and these percentage values then applied to each component day's original value, so reducing it to an approximation for the component of distribution supplied daily heating and hot water in buildings.

   Due to the different seasonal impact on heating from one quarter to another there were variations between the percentage adjustments e.g., in Q1 2019 the adjustment factor was 87%, whereas Q3 of the same year required 64%. To reduce the impact of the step change between subsequent quarters, a linear smoothing between the values was used over the three weeks before and after the quarter transition, i.e., it took 6-weeks to change linearly from one quarter's adjustment factor to the next.
7. **Validation of methodology** – firstly, the values from '2', '5' and '6' were combined to represent the supply of heat and hot water in buildings. The resulting 5-years' worth of data representing the GB heating and hot-water requirements in buildings supplied by gas through the distribution networks are now available for download[20]. Secondly this was combined with the derived electricity supply data from '1' and the empirical estimate for process heat from '6' to give a 'bottom up' estimate for total gas supplied from the distribution networks based on the BEIS user data. This total was found to match

closely to the metered value from National Grid's quarterly *LDZ Offtake.* Over a period of 5 years the total difference was only -0.8% (individual quarters ranged between -6% and +4%). These derived values are therefore likely to represent an improved estimation of heat use.

7.4 Methodology – normalisation of wind and solar capacity

The electricity generation data from ELEXON (metered transmission connected) and National Grid (estimated distributed generation) was analysed to take account of quarterly capacity additions throughout each year as recorded in the *BEIS Energy Trends Table 6.1* (BEIS, Renewable electricity capacity and generation, 2021). To do this, it was assumed that the quarterly installed capacity for wind (onshore plus offshore[G]), and solar photovoltaics was reached at the end of each quarter through linear additions across each day of the quarter. With a calculated approximation of daily capacities and the daily output for the same day from solar and wind a daily time-series of load factors for solar and wind was constructed.

Daily Load factor (%) = Recorded Daily Generation (GWh) x 100%/(Calculated Installed Capacity (GW) x 24 (h))

Taking quarterly capacity additions and a linear installation over the quarter can reduce the impact of lumpy capacity additions on the daily load factor calculation. Without this linear increase, the year- or quarter-end values do not take account of the lower installed capacities earlier in the period so the calculated daily load factors over the year/quarter are too low early in the respective periods.

7.5 Methodology – scale and simulation

For each scenario and year, the wind and solar generation capacities were scaled to exactly meet the respective energy demand as follows:

1. From the average of the normalised daily load factors described above, and the target annual electricity production required to meet the demand scenario with the respective mix of wind and solar (e.g. 85:15, wind:solar, for the majority of the analysis), the required installed capacities for that year of wind and solar were calculated.
2. These annual capacities were combined with the individual daily normalised load factors for each technology to create the relevant daily generation time-series for wind and solar. These datasets are now available for download[21].

An approximation of heat demand with electric radiators was achieved by adding the heat time-series dataset to the electricity demand time-series dataset in its entirety.

Calculation of heat demand with heat pumps was achieved by applying a coefficient of performance (CoP) factor to the heat time-series dataset. A combined heat and hot water CoP of 3 was used between April and November and 2 between December and March. For a period of 3 weeks either side of the season change the CoP was increased or decreased linearly to smooth the transition. These CoPs are consistent with results quoted by the CCC for ASHP with a combined (heating and hot water) Seasonal Performance Factor across the year of 2.5[22].

7.6 Data runs

For the system value, the demand data was subtracted from the generation data on a daily basis. More details of the computing methodology and scripts used to process the data can be obtained from co-author Noah Godfrey.[23]

[G] Onshore and offshore wind were treated as total wind with an average load factor throughout the calculations.

8 Further scale considerations

8.1 Resilience

All of the simulations are based on an 'ideal' system where overall generation output exactly matches demand on an annual basis. This leaves no room for contingency reserves to provide resilience against unexpected shocks. Government will make the strategic political decisions to set the expected resilience levels, as it does with the current energy system, e.g. for oil reserves and electricity capacity. Building in strategic resilience will add to the scale of the necessary balancing solutions needed and is an area that requires greater levels of analysis and evidence.

8.2 Curtailment and constraint

Traditionally, flexible fossil-fuel generators ceased to produce when demand exceeded total generation, intuitively reducing output to save on their high marginal generation costs, mainly fuel. Now, with more low carbon generation, typically having low or zero fuel costs as well as production-based incentive payments, price signals are often insufficient to 'automatically' reduce generation levels. Inflexible generators, like nuclear, have a high technical cost to adjust output up or down.

As a consequence, fossil-fuel generators will pay the Electricity System Operator to have their output reduced in line with the savings in their fuel costs. However, with renewable generators the System Operator must pay them to curtail generation when there is insufficient demand. This is even more extreme with nuclear or CHP generators which can charge very high, penal prices for curtailment.

Generators also receive constraint payments to reduce or stop production when, even though there is enough demand, there is insufficient network capacity to transfer the energy across the system.

The energy and capacity calculations used in our simulations are based on wind data reported through the balancing mechanism and National Grid. The wind generation data is thus **after** curtailment and constraint has happened. In the above results this could lead to an overestimate of the generation capacity requirements and to suppression of the extremes of imbalance due to over-production. In each of the years 2015 to 2019, the combination of curtailment and constraint restricted 1-2 TWh of generation, equivalent to about 3% of total wind production[24], therefore any correction for such effects might slightly change the scale, but not the orders of magnitude of imbalance shown in the paper.

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None of the findings in this paper necessarily reflect the opinions of any of the individuals or the organisations to which they are associated.

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