Enabling Renewables to Power Grids
using innovative forms of
Compressed Air Energy Storage

Matching the Solution to the Problem

An analysis of Future Energy Scenarios 2020[1]
Published by National Grid plc

By
Mark Howitt
Chief Technical Officer and Co-Founder
of
Storelectric Limited
www.storelectric.com

Contents

[1] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

Introduction

This analysis has been almost entirely re-written as compared with previous years.

This FES builds on the vast improvements of the 2019 analysis, and is the best FES that National Grid have produced, incorporating many of the points on which we have provided feedback over recent years. They have adopted three scenarios consistent with the 2019 Net Zero legislation (which became law too late for incorporation into FES 2019) and, for comparison purposes, one scenario that envisages steady progression on some continuation of current policies. This excellent choice of scenarios enables us to evaluate the costs and benefits of each compliant scenario in comparison with Steady Progression, benefitting legislators, government and industry decision makers. Note that Net Zero applies to the entire economy.

The foci for Net Zero are:

- Hydrogen for 21-59% of energy needs, from methane reformation plus CCUS, heating ⅔ of homes;
- Carbon Capture, Use and Storage (CCUS) for industrial clusters;
- Continuing unabated gas combustion, its emissions balanced by BECCS (bio-energy with CCUS);
- Heating demand reduced by ¾, met by at least 8m domestic hybrid heat pumps, over 40% of which will have thermal storage;
- 75% reduction in vehicle energy demand
- Major changes in human behaviour, such as active management of heat and other energy.

In the electricity system, on which this report focuses, the scenarios require

- Over 40GW energy demand, to be met by over 132GW more renewable generation capacity –
  - Over 71% of demand is met by renewable generation;
- Up to 38GW Vehicle to Grid (V2G) electricity storage from 5.5 EVs, which needs to be reduced by a factor of 7;
- The electricity system alone drops below Net Zero by the mid-2030s.

Although the scenarios are much improved, in that they aim for Net Zero, and though there are many improvements in specific technology forecasts (e.g. overall demand, nuclear capacity), others are a combination of unaddressed issues (e.g. CCS, DSR, interconnectors) and new contributory technologies whose inclusion is good but whose treatment gives rise to new concerns (e.g. hydrogen, bio-energy).

Conclusions

The requirement for large-scale long-duration electricity storage has increased over previous years' assessments to account for the Net Zero target, in which the power system is negative emissions by the 2030s. **Total storage needed is 20-40GW** as stated in FES 2020, a quantity that only large-scale storage can provide. There is no

statement as to the duration of such storage, but FES 2019 stated (consistently with the National Infrastructure Plan and the Technology Innovation Needs Analysis) that most of it needs to be long-duration, defined as greater than 4 hours. This increases by a further 19-28GW by 2030 and 22-46GW by 2050 taking into account the following considerations.

Despite these excellent improvements, there are a number of points of concern, for example:

1. While FES tries hard to model the economy and energy system as a whole, **Total process efficiency and costs** are not fully accommodated, e.g.:
   - CCS consideration does not allow for the additional capital costs, the inefficiencies (up to 30%) it imposes on the "host" plant (e.g. power station), or the risks of leaks in capturing, transporting and storing a colourless, odourless, asphyxiating gas that is heavier than air;
   - Flexing renewable generation with electrolysis igores that 3-6 times as much expensive electrolysis equipment would be needed than if powered by baseload electricity;
   - Flexing variable demand with hydrogen-fired power stations does not account for a 30-40% round trip efficiency (electrolysis to power station) and much more expensive round trip capital and operational costs than 70% efficient large-scale long-duration storage like adiabatic CAES.
2. There is little recognition of the **effects on grid infrastructure** and required investment of their chosen energy mixes; for example:
   - Widespread roll-out of EVs would require prodigious reinforcement of distribution grids even if chargers are 100% smart;
   - Reliance on interconnectors almost guarantees black-outs some future during times of system stress;
   - Connecting large renewables (especially offshore wind) to grids directly rather than through large-scale long-duration storage –
     - doubles or triples grid reinforcement,
     - ditto whole-system reinforcement as balancing actions are remote from the farms,
     - creates a large requirement for investment in flywheels and synchronous condensers because inertia is not put into the system at the renewables' connection points.
3. The continuing focus on statistical-average measures such as Loss of Load Expectation (and on TWh annual consumption rather than peak/trough GW usage) gives rise to inadequate treatment of **resilience for predictable events**, e.g.
   - They only address "a 1-in-20 peak winter day" with natural gas (and consequent emissions) and don't consider cold spells such as the *kalte Dunkelflaute* (cold dark doldrums) which extend such periods for up to a fortnight and simultaneously make heat pumps and batteries less efficient;
   - Nearly all European countries' energy transition plans rely on imports during largely concurrent times of system stress (low renewable generation and/or high demand, which can extend for days or even

weeks), so we can't rely on there being a surplus for us to import – yet the scenarios rely on 22-27GW interconnectors to keep the lights on;

- A focus on distributed systems relies on their self-sufficiency, whereas in reality they rely on the grid for back-up during times of system stress as it's prohibitively expensive to provide such back-up in distributed manner, yet FES 2020 does not identify a need for the capabilities to provide such grid-based back-up;
- Renewable generation moving (due to weather patterns) from one part of the country to another requires sufficient capacity for the entire system's needs to be carried in each part of the country, unless there is sufficient large-scale long-duration storage;
- The Lockdown proved the high costs (forecast >£1bn p.a. by the 2030s even in an 80% renewable grid) of providing real inertia even when there are no gas-fired power stations able to produce it – large-scale long-duration storage (of all types) can; Storelectric's can 24/7.

4. **CCUS (Carbon Capture, Use and Storage)** doesn't account for costs and inefficiencies imposed on the host system, e.g. power generation, or on the leakage risks in the capture transport and storage of an asphyxiating, odourless and colourless gas that is heavier than air. While it's necessary for industry clusters that cannot decarbonise intrinsically, for the energy sector it's too expensive, inefficient and dangerous in comparison with widespread roll-out of large-scale long-duration storage.
   - Utilisation (the U in CCUS) is mostly delaying emissions (e.g. re-processing it into fuels and plastics, both of which are then used/disposed of) rather than capturing the emissions permanently.
   - CCUS is less than 100% effective and its costs and inefficiencies increase exponentially towards 100%.
5. Treatment of **transportation** is fanciful and encourages counter-productive legislation, regulation and investments, the most egregious examples being:
   - Most vehicles will have to be hydrogen / fuel cell as:
     - There are insufficient raw materials in the earth's crust;
     - Large numbers don't have access to personal charging points;
   - Of the battery EVs, only a small fraction (maybe 10%) of their storage will be available for V2G, and the grid will have to pay for their battery degradation;
   - Autonomous Vehicles will indeed decrease the number of vehicles in service, as per the scenarios, but in doing so they will actually increase mileage and hence energy consumption, not decreasing it, as they travel between rides; this will also increase the number of vehicles on the roads at any given time.
6. Consideration of **grid-connected battery storage** remains deficient and counter-productive, as:
   - There are insufficient materials, as the point on EVs, above;
   - Doubling the size and/or duration of batteries increases capital costs by 70-85%, whereas the proportion is less for other technologies;

- Their capital costs are grossly under-stated, focusing on the equipment and ignoring land, grid connection, building and ancillary costs;
- Their average life-time efficiency is less than other technologies as they use promoters' information which tends to deliberately ignore:
  - Ancillary loads: cooling (~10%), inverters (~5%) and other, and
  - Aging: efficiencies are quoted on day 1 whereas cells require three times as much cooling by swap-out, and cell and inverter inefficiencies double or triple over their lives;
- They provide only synthetic inertia: while it helps grids recover from faults, it does not prevent faults like real inertia does – and ditto all the other related stability services that grids need.

7. The large amount of **bio-energy and BECCS (Bio-Energy with CCS)** is difficult due to lack of availability of feedstock, and the large environmental harm in growing, processing and distributing it. Much of it would also be unnecessary if there were more focus on cheaper and more efficient large-scale long-duration electricity storage.
8. There is no statement on **duration of storage** required. FES 2019 was clear that most storage requirements (other than E2V) were large-scale long-duration, defined as over 4 hours' duration.
9. There is no statement on grid **stability services**, which all large-scale long-duration storage can provide (and Storelectric's plants will be able to provide double, 24/7, whether charging, discharging or neither) even though:
   - During the Lockdown, in a partial foretaste of a 2030s grid (renewables as a high proportion of demand), the National Grid paid £10-30M per day to ensure sufficient such services, and put out a forecast commensurate with spending over £1bn p.a. on them by the 2030s; and
   - These services were delivered by turning up gas-fired power stations, most of which are likely to close by the 2030s – though gas+CCS and BECCS could also provide them if sufficient are built and operated.

Conclusion: these scenarios are a plan for periodic widespread blackouts.

The Scenarios

The four scenarios are:

1. Steady progression: the comparator for the other scenarios regarding the costs and benefits of policies and actions: this is a reasonable outcome without substantial further movements towards Net Zero.
2. Consumer Transformation achieves Net Zero as driven by consumer-led behaviour change, adaptation and investments: the bottom-up approach.
3. System Transformation achieves Net Zero by transforming the country's energy systems and infrastructure, so as to minimise the requirement for behavioural change: the top-down approach.
4. Leading the Way achieves Net Zero 2-3 years early, based on a mix and match of top-down and bottom-up changes.

Steady Progression (SP)

Steady Progression is the scenario that assumes minimal change from the country's present course of legislation, investment and consumer behaviour. These all continue to develop in environmentally-friendly ways, but without any major new impetus towards Net Zero. It is therefore the "steady-as-she-goes" scenario with minimal change in human behaviour, and no substantial new actions by governments or the energy industries (i.e. those producing, transporting and/or consuming energy). Fossil fuels are still used for HGVs and plug-in hybrid vehicles, and few energy efficiency improvements are made. Almost half of all energy consumption is natural gas for heating and industry. Emissions only reduce by ~40% from 2019, or 68% from 1990, to 258 $MTCO_2e$ (million tonnes of carbon-dioxide equivalent).

All Net Zero Scenarios

To a greater or lesser extent, people buy and use smart appliances, electric vehicles (providing V2G services), heat pumps and domestic heat storage. Industries that cannot decarbonise will relocate to energy clusters which have CCUS networks.

Consumer Transformation (CT)

Achieving Net Zero by 2050, Consumer Transformation assumes consumer-led behaviour, with a very high degree of behavioural change driven by both legislation and individual / social action.

This degree of societal change reduces overall energy demand, and the scale and speed of demand peaks and troughs. The bulk of investment is decentralised, such as insulation, vehicles and heating systems which incorporate much more energy storage at domestic and commercial scale. Much more public transport is used, and cars are mostly electric plug-ins. Most demand is met by the electricity supply (including heating by heat pumps rather than hydrogen, and more district heating than other secarios), which is highest in this scenario even though total energy demand is lowest.

People change behaviours to consume energy when most plentifully available. 20% energy efficiency targets are met by 2030. As there is no wholesale conversion to hydrogen, industries using it will relocate to energy clusters.

System Transformation (ST)

Also achieving Net Zero by 2050, the bulk of the change is at system level so as to minimise the need for behavioural change. The most momentous difference is a major roll-out of hydrogen technologies, including conversion of the gas grid to hydrogen, which provides well over half of all energy consumed. Heating boilers are largely converted to hydrogen, with much lower roll-out of heat pumps.

Because consumer behaviour and distributed / commercial investment are lower, total energy demand is over 60% higher than Consumer Transformation. 20% energy efficiency targets are met only by 2050.

Leading the Way (LW)

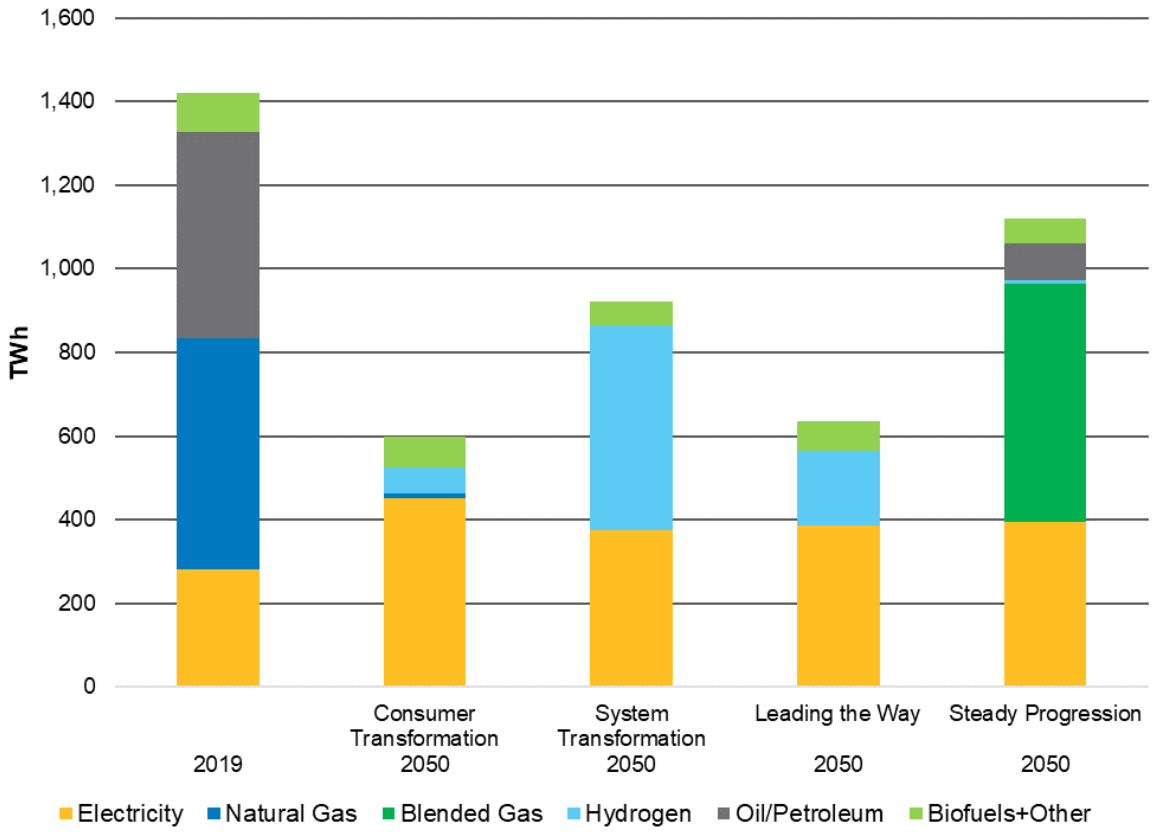
Leading the Way takes “the best of both”: most (but not the least cost-effective) of the top-down investment and system changes, together with most (but not the most personally disruptive) behavioural change and consumer / social action. It too will involve the conversion of the gas grid to hydrogen, though with less demand than ST as much will be electrified. Although the most ambitious, achieving Net Zero in 2048, its absence of extremes is why we consider this scenario the most likely, so it will be the primary focus of this analysis.

In keeping with the “happy medium” approach, electricity demand is only a little higher than ST and ~20% below CT; total demand is ~10% above CT and ~30% below ST. Hydrogen is over four times CT but barely over ⅓ of ST.

25% energy efficiency targets are met by 2030.

Total Demand

Peak demand is more realistic than previous years’ FES, approaching 80GW for System Transformation and Leading the Way scenarios, and exceeding 95GW for Consumer Transformation. This looks low, due to the moderating effect of large amounts of “smart energy” systems (especially smart vehicle charging) and changes in consumer behaviour. We are not confident that such enormous smoothing is realistic, but will work with it.



However it should still be treated with some caution as there are also very substantial changes that decrease energy efficiency in the whole system, e.g.

- Hydrogen production is necessarily energy inefficient, whether by methane reformation or electrolysis;
- Hydrogen transportation through the gas grid is more energy intensive as it carries about one-third of the energy per m^3 of the gas;
- Autonomous vehicles will lead to a significant increase in total mileage;
- Imports of biofuels increases energy demand – as does domestic production of feedstock, by displacing agriculture which in turn increases food imports.
- Increasing gadgetisation and “intelligent systems” all demand electricity.

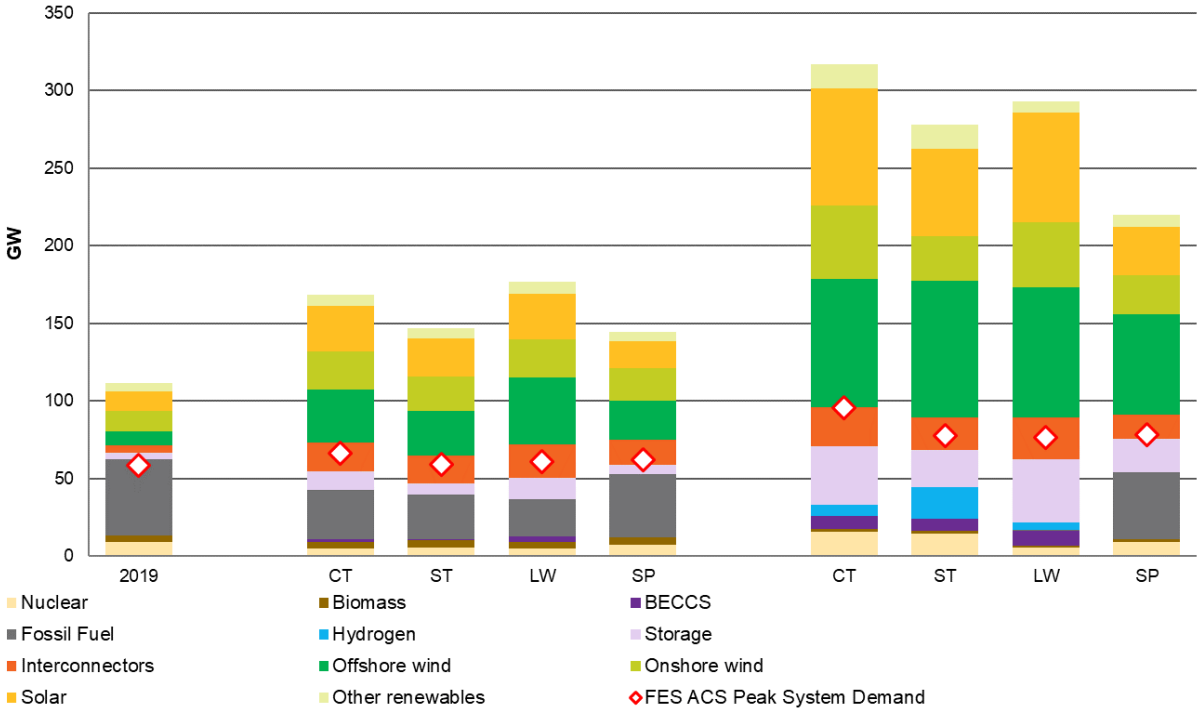
Nevertheless, the remainder of this report will assume that National Grid is correct in its forecast electricity demand.

Supply Side

Generation Mix

In FES 2020, energy supply is from the following technologies (stacking baseload generation at the bottom, then dispatchable, then interconnectors and finally intermittent generation):

:



This looks like a serious risk: the country is depending on imports for actual demand, without even taking into account either supply margin (10-15% to be added to demand) or the lack of duration of most of the storage concerned. In the Net Zero scenarios, by 2030 this shortfall is 19-22GW; by 2050 it is 21.5-39.5GW. Even in the do-nothing Slow Progression scenario the shortfalls are 12.6GW by 2030 and 14.75GW by 2050. And in every scenario except Slow Progression, the shortfall is greater than the country's capacity to import.

V2G is assumed to provide up to 38GW storage – which would be inadequate for the CT scenario and barely enough for the LW. But for reasons described fully elsewhere in this report, this should be reduced by a factor of 7 to 5.5GW.

Not only that, but this does not account for the duration of storage called upon. All battery storage in the country is 1 hour duration or less; a little is planned at two hours. But the evening peak is 3-5 hours, and energy is also needed overnight after windless winter evenings – not to mention the weather patterns (e.g. the *kalte Dunkelflaute* – see Security of Supply, below) which extend these periods to multi-day, and even to up to a fortnight.

And the shortfall is, in all cases **including** the do-nothing Slow Progression scenario, 19-28GW by 2030 and 22-46GW by 2050.

The above are National Grid's unadjusted figures. However demand should be increased by the supply margin, a 10-15% additional allowance to account for the unpredictable, e.g. extra-high demand and/or plant failures such as on the cable from a wind farm. Ignoring the technologies that cannot be relied upon (intermittent and interconnectors) because there are predictable periods when they fail simultaneously (e.g. the *kalte Dunkelflaute* and shorter-duration similar periods, such as after sunset on a windless winter evening), then the distribution of demand and reliable supply is:

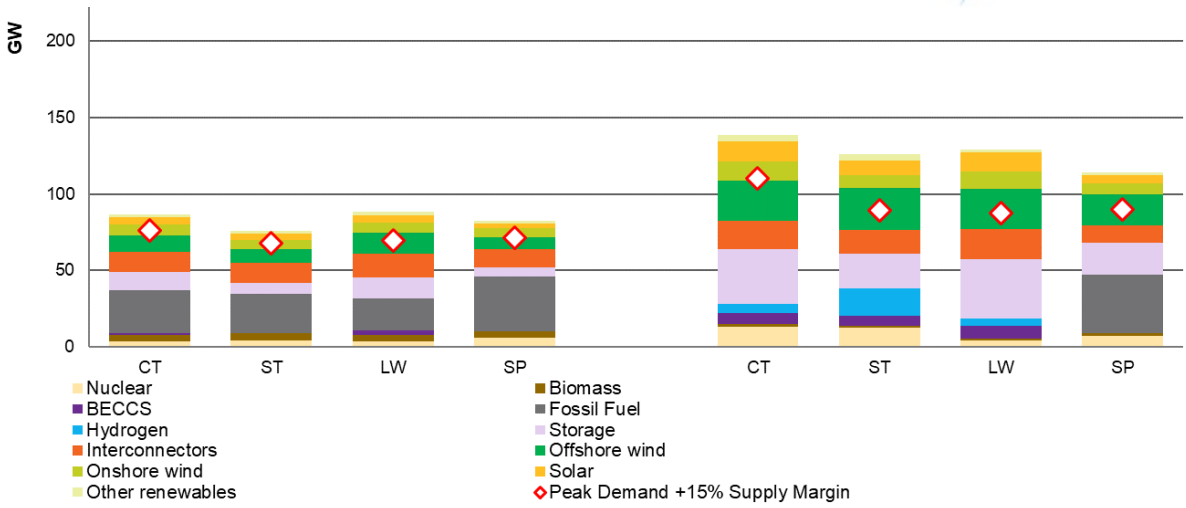
Nominal Capacity	**2030**				**2050**			
Figures in GW	**CT**	**ST**	**LW**	**SP**	**CT**	**ST**	**LW**	**SP**
Demand + 15% Supply Margin	76.43	67.91	69.87	71.47	109.90	89.52	87.69	90.07
Dispatchable	48.11	41.16	42.38	51.82	46.26	45.53	47.08	66.54
Baseload	6.37	5.80	8.17	7.05	24.32	22.52	15.05	8.79
Shortfall	**21.95**	**20.96**	**19.32**	**12.60**	**39.31**	**21.47**	**25.56**	**14.75**
Interconnectors	18.65	17.90	21.45	15.90	25.05	21.45	27.20	15.90

However, the true picture is much worse: these figures don't just ignore the supply margin, but also assume that electricity generation is at nameplate capacity. The technologies should be de-rated according to these factors, which are applied elsewhere[2] by National Grid in their planning and management of the system.

De-Rated Generation	De-rating Factor
Nuclear	85.24%
BECCS	82.58%
Biomass	87.58%
Hydrogen	87.92%
Fossil Fuel	88.54%
Storage	96.11%
Interconnectors	72.17%
Offshore wind	31.60%
Onshore wind	27.30%
Solar	17.00%
Other renewables	27.30%

Applying these factors, the truer picture is:

[2] De-rating factors for biomass, coal, gas, hydro, interconnectors, nuclear, storage, energy from waste, using T-1 de-ratings, section 1.3 (p6): https://www.emrdeliverybody.com/Lists/Latest_News/Attachments/114/Capacity Market Auction Guidelines July 7 2017.pdf
De-rating factors 2017 for wind, DUKES Chapter 5, paragraph 5.43: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/729379/Ch5.pdf
De-rating factors 2017 for solar, DUKES Table 5.7 footnote (4): https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/731590/DUKES_5.7.xls
Fossil fuel: used the figures for CCGT power generation. Interconnectors are averaged, Other renewables: assumed to be equal to on-shore wind. Assumed that all technologies with CCS are 5% lower than those technologies without CCS.
Note: National Grid's assumption is that Vehicle to Grid (V2G) is as reliable as batteries, whereas in reality vehicles are often not available.



The numbers are:

De-rated Capacity Figures in GW	2030				2050			
	CT	ST	LW	SP	CT	ST	LW	SP
Demand + 15% Supply Margin	76.43	67.91	69.87	71.47	109.90	89.52	87.69	90.07
Dispatchable	43.47	36.95	38.54	46.32	43.73	41.95	44.70	60.50
Baseload	5.38	4.92	6.87	6.01	20.51	18.99	12.57	7.49
Shortfall	**27.58**	**26.04**	**24.46**	**19.15**	**45.66**	**28.58**	**30.42**	**22.08**
Interconnectors	13.46	12.92	15.48	11.48	18.08	15.48	19.63	11.48

Therefore all scenarios depend, for actual demand, not only on ALL interconnectors importing simultaneously at 100% de-rated capacity, but also on 10-30GW of intermittent generation during every single peak in demand without exception. And on storage providing energy for the entire duration of need – which the current focus on batteries and V2G does not. (Large-scale long-duration storage can, if built with sufficient duration, for which there would have to be sufficient duration-based revenue streams which don't currently exist.)

In other words, **all** scenarios are planning for widespread and frequent black-outs.

Security of Supply

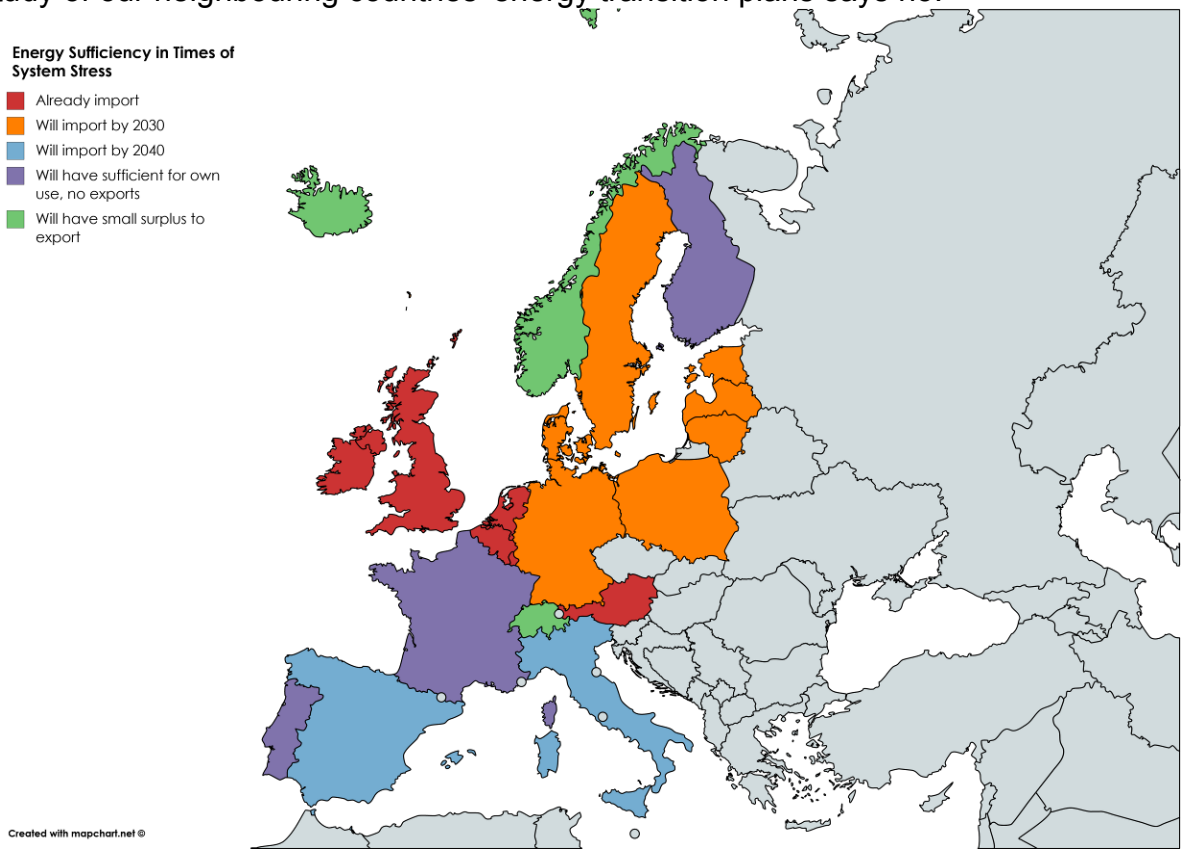
Security of supply means two things principally: keeping power reliably in the grid to meet variable demand, and being in charge of the source of that power. This year is the first year in which we will have insufficient generation to supply the country's needs, relying on imports for actual demand, and also for the country's entire supply margin during "times of system stress"

These "times of system stress" are periods of high demand and/or low renewable generation. They occur every single windless winter evening, and are extended (and occur in other seasons) by weather patterns that yield negligible generation. The largest and longest of these weather patterns is the *"kalte Dunkelflaute"* (cold dark

doldrums)[3] identified by the French and Germans as covering almost the entirety of Western Europe for a fortnight every couple of years; reducing the duration to a few days, and scale to a few countries, makes these weather patterns very common.

Note that as the weather gets colder, the efficiency of heat pumps diminishes, to zero for temperatures of 0 to -8°C depending on the heat pump. This in turn would increase demand for electricity and/or (in the ST and LW scenarios) hydrogen for heating. The increased demand for hydrogen would itself place more demand on electricity, if electrolysed or if electricity were used in the reformation process. Such increases in electricity demand do not appear to have been accommodated in the forecasts.

So the question is: can we rely on imports during such periods? Storelectric's own study of our neighbouring countries' energy transition plans says no:



The only exports will be available from Switzerland and Norway (who will primarily export to their neighbour and, in Norway's case, Germany) and Iceland. The Norwegian interconnector is projected to cost over £5bn for 1GW, for which price Storelectric could build ~5GW storage with durations of 5-12 hours, which begs questions about interconnectors' value for money. An Icelandic interconnector would cost much more, and Iceland only has ~1-2GW exportable energy.

[3] https://energytransition.org/2017/07/germanys-worse-case-scenario-in-the-power-sector/#more-15335 – note the map which shows that the weather pattern includes the UK.

FES relies (p56) on natural gas for resilience, which negates the energy transition.

System Stability

As power stations have closed, grids around the world (led by National Grid) have become increasingly aware of the grid stability services that they produce, such as phase-locked loops, fault currents, voltage and frequency control, RoCoF (Rate of Change of Frequency) reduction following faults, etc. Most of these relate to natural inertia.

As demonstrated by the UK blackouts on 9th August 2019, while synthetic inertia helps recovery from faults, it cannot prevent them; real inertia does. That is because synthetic inertia is basically an ultra-fast response time. But any response time is a delay, and any delay translates a fault into a spike on the mains; it is this spike that does the damage. Real inertia is “always-on”.

Solar and wind generation, interconnectors and batteries are all DC connected and therefore provide no real inertia. All large-scale long-duration storage (CAES, pumped hydro, even LAES though that is medium-scale) uses large rotating machines and therefore produces real inertia. Storelectric’s CAES is configured to produce twice the real inertia of a power station, and to do so 24/7 – whether charging, discharging or neither. Without such inertial plant, the grid would have to invest in flywheels, synchronous converters or similar.

Please see Appendix H for more details.

Trends

Large-Scale Long-Duration Storage

For the first time ever, from this winter the UK does not have sufficient generation to supply its own peak demand, and therefore relies on imports through interconnectors – which are not reliable, see comments on interconnectors below. Therefore the country must rely on storage for the difference, plus supply margin[4].

Demand for energy storage growing strongly and continuously, to 20-40GW by 2050 in all scenarios *including* the do-nothing Slow Progression scenario. It is notable that energy storage requirements have grown in every FES since at least 2013, and the analysis above shows that it needs to increase much more – probably doubling.

[4] Supply Margin is the amount of excess capacity required, that is able to be brought into service at short notice, to support the grid in case of a surge in demand and/or outages in the system. Most EU countries target 15%, though 10% is considered safe. The UK’s current 5% is considered risky.

There is no statement about the required duration of storage, but FES 2019 stated that the majority of new storage should be long-duration, defined as over 4 hours. The 2013 Technology Innovation Needs Analysis (TINA[5]) rightly identified a need at that time for 28.4GW new storage (which is very similar to today's Community Renewables figure, plus the storage built since then), with an average duration of 5 hours (the storage built since then has an average duration of about one-tenth of that).

It would help considerably if storage were to be split into sub-2-hour and over-2-hour storage: the technologies congregate into those two clusters, with typical durations of 0.5-1 hours and 4-12 hours.

Simply multiplying load factors of generation by efficiencies (~2/3) of storage yields the rule of thumb that the following alternatives can deliver 1GW baseload:

- 1GW nuclear
- 3GW offshore wind plus large-scale long-duration storage
- 4GW onshore wind plus large-scale long-duration storage
- 6-10GW solar plus large-scale long-duration storage

To deliver dispatchable electricity, we can assume about one-half of the large-scale long-duration storage, both scale and duration in combination with significant batteries (est. 2-3GW) and DSR (similar – see DSR below).

Large-scale long-duration storage of all types has another feature: natural inertia, and related network stability services. These deliver services which cannot be synthesised from batteries and other DC connected systems: while the latter can help recover following outages and other grid disturbances, they cannot prevent them: only natural inertia can.

Another feature of large-scale long-duration storage is its synergies with renewable generation. For example, it can:

- Halve the size of grid connection (or double the amount attached to an existing connection) of offshore wind – for onshore wind the factor is up to 3x, for solar up to 6x – depending on the output profile wanted –
  - Reducing grid access charges by a similar proportion,
  - Eliminating grid connection costs and ongoing access charges for the storage in doing so;
- Reduce grid reinforcement in proportion to the reduced connection sizes;
- Eliminate use-of-system charges for the renewable generation –
  - And for energy input to the storage;
- Deliver all the output with real inertia;
- Deliver it at >80% efficiency depending on configuration.

[5] https://www.carbontrust.com/resources/reports/technology/tinas-low-carbon-technologies/, which is analysed in greater depth in Appendix A below.

De-Carbonisation

It is good that three scenarios assume that the UK adheres to its Net Zero legislation. (Retaining the Slow Progression scenario as a comparator is also good.) The recognition that the power / electricity sector is among the easiest to decarbonise, and becomes carbon negative in all compliant scenarios from the 2030s, is also excellent; there are many sectors harder to decarbonise such as some industries, aviation and shipping. However this legislation needs to be supported by active governmental leadership, actions and funding in every sector of the economy if it's to evolve from wishful thinking to an achievable objective.

Actions needed in the electricity sector include incentivisation of:

- Large-scale long-duration storage, including first-of-a-kind (FOAK) plants of new or substantially improved technologies;
- Correct regulatory definition of storage as storage (not generation), so as to level the regulatory playing field, encourage and enable investment, and stop subsidising foreign generation at the cost of UK bill-payers (see Appendix E);
- Major capital investment, by long-duration contracts without a requirement for market-distorting special financial instruments such as CfDs, ROCs, CATOs, OFTOs etc.;
- Energy efficiency in buildings and appliances;
- De-carbonisation of transportation and industry;
- Development of alternative chemical processes, e.g. in cement and plastics manufacture;
- Large-scale hydrogen creation, especially by carbon-free means e.g. electrolysis – there are suitable technologies for such scales (Proton Exchange Membranes [PEM] are not one of them at such scales and required operational lives) but these are not currently being incentivised;
- Heat storage for domestic and commercial use;
- Recycling and re-use of batteries;
- Permanent carbon sequestration (most "use" technologies in CCUS merely delay emissions by using the carbon for products that will eventually be scrapped).

One of the simplest regulatory changes needed, for which both BEIS and Ofgem have frequently expressed support but never got round to enacting, is changing the regulatory treatment of OFTOs and similar arrangements, to enable renewable generation to benefit from storage anywhere from the generation farm to the onshore grid. Currently offshore wind farms are metered offshore, so they cannot benefit from onshore storage which would provide enormous benefits for farm, grid and storage owner/operators alike, which would substantially lower overall system costs for consumers).

Unfortunately this year (and last year) there is no analysis of the expected carbon intensity of electricity; 2018's did, though it omitted any emissions relating to imported electricity – see Appendix C on interconnectors. They account for up to 11% of total annual demand in 2030, though dropping by 2050 to a range between 7% imports and 12% exports. National emissions figures should be increased

proportionately on the assumption that imported interconnector-related emissions are comparable with the UK's (exports have no effect).

Also omitted are any emissions relating to biomass cultivation, shipment and processing, which are very substantial[6] although "classed as carbon neutral" (p93). While the material used may be waste, there are limited amounts of such waste (which also reduces composting), and the emissions required to ship it (principally from North America and the Baltic States) and process it (especially drying) prior to combustion are substantial, even if not at the scale proposed by reports such as the one referred to in the cited article. Indeed, the reliance on biomass feedstock being "energy dense and easy to transport in compressed forms" just emphasises this: such compressed forms require considerable energy-intensive processing.

De-Centralisation

All scenarios envisage an increase in de-centralised electricity production, largely based on rooftop solar and onshore wind generation, backed up with on-site batteries. In combination, they greatly reduce demands on the grid in terms of MWh, as well as smoothing electricity flows for short durations while the renewables are generating or the batteries are providing back-up.

However distributed generation and storage needs back-up from the grid: this is why the grid was built in the first place. During longer duration weather patterns, renewable generation can shrink to negligible scales for up to a fortnight at a time. Therefore all distributed systems, if they are to remain cost-effective (i.e. not having to finance enormous and expensive battery storage for long duration back-up), must rely on the grid for back-up. Therefore the grid needs sufficient energy supplies to provide such back-up. It cannot rely on interconnectors (see Appendix C), so must rely on a combination of baseload generation (energy from waste, geothermal, nuclear) and large-scale long-duration storage. While emissions are allowed and the plants remain operational, this would also include fossil fuelled power stations. That combination must be sufficient to power the grid (both transmission and distribution grids) for a fortnight, to prevent blackouts or brown-outs (the jargon is increasingly referring to enforced demand-side measures, which are brown-outs by another name).

The Energy Trilemma

Until recently, governments and grids in Britain and throughout Europe (ENTSO-E is the trade body for transmission service operators of 38 countries) have defined their future needs as an energy trilemma: a need simultaneously to deliver affordability, clean energy and security of supply. A few years ago all talk of the Energy Trilemma has vanished from BEIS, National Grid and Ofgem communications; however, this does not mean that the trilemma no longer exists: all three elements need to be delivered, or the country will suffer both political and economic consequences.

---

6 https://www.edie.net/news/10/UK-biomass-energy-generation-environmental-emissions-impact-report-NRDC/

Technologies

Electric Vehicles (EVs)

All scenarios of societal change expect there to be at least one EV charge point per house. But a large proportion of housing has no on-property or dedicated parking, and so does not have the ability to fit EV charging. These properties will rely on charging away from the homes which is expensive and inconvenient; hydrogen fuel cell vehicles, which charge like today's petrol and diesel vehicles, would be much more practical for them.

Higher degrees of societal change rely on increasing use of autonomous vehicles (AVs), and therefore fewer vehicles in service. But this is predicated upon the false premise that fewer vehicles translate into lower energy consumption: in reality AVs actually increase energy usage by adding onto the number of passenger-journeys an extra number of non-passenger journeys to travel between drop-offs and pick-ups. Incidentally, this would also greatly increase road usage and congestion, unless use of bicycles and public transport is vastly increased.

The mix of battery and fuel cell vehicles is debateable too: there is insufficient lithium in the earth's crust for most to be powered by lithium batteries[7], without considering scarcer elements. And hydrogen production is an inefficient process, measured by usable energy output to all energy input, especially if derived by methane reformation with CCUS. This would reflect on the amount of renewable generation required, and on the capacity of hydrogen production plants which would have to be increased greatly if they are to be powered by intermittent energy. It makes intellectual sense for heavily-used vehicles of all types (high mileage, long ranges and/or large loads) to be powered by hydrogen and less-used vehicles to be battery powered. Incidentally, for the same reason it makes no long-term sense to use lithium batteries (whose main features are portability and energy density) in grid applications where neither size nor weight are critical issues.

NG state that, from measured experience, vehicle charging peak times are later than current peak demand times. However they give no GW figures for peak demand.

Smart charging of vehicles will indeed displace electricity demand to off-peak periods. But the total energy consumption cannot be smoothed out to the extent envisaged by FES 2019, which appears to assume that daily electricity demand is largely flattened.

- People don't operate like this: they need to use their vehicles at certain times, and have preferences as to how, where and when they will be charged.

[7] There is sufficient recoverable lithium in the world to power only 77% of vehicles by 2080, ignoring any use of lithium for the electricity sector (which uses three time as much energy as transportation, including gas as it will be replaced by both P2G and electrification), portable devices and other uses https://www.researchgate.net/publication/264854684_Lithium_Resources_and_Production_Critical_Assessment_and_Global_Projections.

- A low- or zero-carbon electricity grid doesn't operate like this unless there are massive amounts of large-scale long-duration electricity storage envisaged, far more than forecast by FES 2019.
- Flattening daily demand would destroy the financial incentives of storage, so new incentives would have to be developed.
- Such a high degree of flattening would be constrained by grid reinforcement, which runs counter to today's policy of only reinforcing the grid to reflect need, and sweating grid assts as much as possible: only a few thousand vehicles added to a forecast can yield black-outs if the grid is insufficiently reinforced, and historical forecasts of EV uptake have been grossly unreliable.
- To achieve this would require recognising in legislation and regulations that storage is a grid service, not a form of generation.

A large proportion (how large is not stated; in 2018 it was 8-10GW) of storage is Vehicle to Grid (V2G). These assumptions and forecasts require some challenging; for example,

1. All the cars in the country, if turned into EVs that are 100% used for grid-connected storage, would account for only a part of the storage needs – they consume similar amounts of energy to the entire electricity grid, with only a 2-4-hour range, only half of which at most (if the system works flawlessly) would be available to the grid. Therefore it lacks the duration to provide true back-up for renewables.
2. Where they charge from solar power (office, shopping), which is the proffered model, differs from where they would operate as grid-connected batteries, and nobody has proposed a cost-effective model for the financial flows.
3. Most people don't want their vehicles on less than half charge, which halves (or less) the energy/storage available.
4. The bulk of the need for the storage is in the evening, when vehicles' charge is lowest, yielding a grossly disproportionate multiplication of point 3.
5. To roll out cars-with-solar widely, a high proportion of the parking spaces in the country would have to be fitted with chargers - who would bear the cost of that?
6. A large proportion of homes do not have dedicated parking, let alone on-property parking, making recharging much more costly and inconvenient and rendering a hydrogen distribution system (similar to current petrol and diesel distribution via filling stations) look very attractive for such residents.
7. Distribution grids need upgrades at enormous cost and ahead of actual demand in order to accommodate variability between forecast and actual EV take-up.
8. If the 40-60 gigafactories currently planned world-wide are built, they would exhaust the lithium deposits in all current and under-development fields in

2-10 years according to figures from The Economist[8]. The earth's crust doesn't have enough for all the world's vehicles, OR the world's energy systems, even without considering portable devices. Cobalt and other "rare earth metals" are in much shorter supply.

9. Therefore at least ⅔ of zero-carbon transport (including all the larger-size, longer-distance and heavier-use vehicles) should be hydrogen / fuel cell powered – which again reduces the amount of storage available for V2G.

The above-listed challenges would need to be answered for V2G storage services to be reliable. And it appears that FES 2019 assumes 100% efficiency in V2G services, which will not be attainable: a perfectly new battery requiring no cooling yields ~96% efficiency, whereas one approaching its end of life yields ~75%, so a reasonable assumed average efficiency would be ~85%; then there are converter efficiencies – 90% is reasonable[9], which has to be applied twice – once for charging and once for discharging. The total round trip efficiency is therefore .85 x .9 x .9 = 0.6885 or 69% round trip.

Analysing this roughly, FES 2020's assumed 50% availability of V2G is a gross exaggeration. They will be at different states of charge, so assume 50%. Travelling capacity will need to remain in the vehicle, so halve that to 25%. AVs are almost never available, so reduce this to 20%. About 2/3 of vehicles must be hydrogen / fuel cell because there isn't enough lithium in the earth's crust, so actual availability is ~7%.

Grid Connected Batteries

Grid connected static batteries require cooling and therefore achieve lower grid-to-grid round trip efficiencies despite slightly more efficient converters: actual measured grid-to-grid efficiencies of grid-connected batteries are 42-62%[10], though some manufacturers claim that since that study their grid-to-grid efficiency has improved to figures as high as 85%, though that figure's credibility has not been demonstrated to

---

[8] https://www.economist.com/news/briefing/21726069-no-need-subsidies-higher-volumes-and-better-chemistry-are-causing-costs-plummet-after -

Vehicles, 2016	25	GWh	750,000 vehicles
Mid-range: 2040 Bloomberg	15,500	GWh	465,000,000 vehicles
2040 OPEC	5,000	GWh	150,000,000 vehicles
2040 ExxonMobil	3,000	GWh	90,000,000 vehicles
Total lithium, 2016	180,000		tonnes in one year
2040 Bloomberg	111,600,000		tonnes in one year, just for vehicles
2040 OPEC	36,000,000		tonnes in one year, just for vehicles
2040 ExxonMobil	21,600,000		tonnes in one year, just for vehicles
Total available lithium in planet	210,000,000		tonnes
Years' output: 2040 Bloomberg	1.9		years, just for vehicles

[9] https://www.electronicdesign.com/power/understand-efficiency-ratings-choosing-ac-dc-supply graph

[10] http://www.networkrevolution.co.uk/network-trials/electrical-energy-storage/ Electrical energy storage cost analysis paper – see round trip efficiency including parasitic losses, chart on p6

us. The inefficiency (in the North East of England, not a hot location) about ⅔ due to cooling and ⅓ due to inverters; there are other smaller elements.

Batteries are also measured on day 1 rather than average life: by end-of-life battery cells require three times as much cooling. In addition the electronics of both batteries and inverters deteriorate over their lives such that these losses double or triple. Applying these factors to an 85% efficient battery at day 1, its average lifetime efficiency drops to well below 72.5%.

Further information is in an appendix.

Heating

Both scenarios envisage a huge up-take in heat pumps, which carry two challenges: (a) power consumption and (b) cold weather cut-out, both of which are improving but both of which have natural limits to that improvement. Happily, FES 2019 now takes account of the former, but not of the latter which would lead to a surge in electricity demand in cold weather, at exactly the time of day of peak demand for domestic-use and transport-charging electricity, leading to the risks of (a) greatly underestimating electricity demand, particularly in winter, and (b) black-outs during cold spells as heat pumps cut out and buildings revert to (much higher electricity consuming) direct heating.

Hydrogen

Two scenarios envisage a major roll-out of hydrogen grids. We agree that this will be both beneficial and necessary for the country, for many reasons. But where does this hydrogen come from? Either there are vast assumptions about the introduction of CCS (Carbon Capture and Storage) into the methane reforming industry, together with zero electricity consumption during the energy-intensive reforming process, or there is a substantial electricity demand to either reform or electrolyse the hydrogen – or, more likely, a mix of the two processes.

Electrolysis consumes 41.4kWh/kg (335kJ/mole) of hydrogen produced, with a theoretical limit of 32.91kWh/kg[11]. Combustion yields 286kJ/mole[12] = 35.3kWh/kg. Thus burning hydrogen is 85.3% efficient as compared with electric heating, assuming all equipment and storage are 100% efficient. However, these are theoretical: the capabilities of current equipment yield efficiencies in the high 20s or low 30s % as (for example) gas turbines are actually 50-64% efficient burning gas, and less so burning hydrogen. Figure 4.26 of FES 2018 (p87) indicates that 44TWh electricity produces 33TWh hydrogen, or 1.33TWh electricity per TWh hydrogen, 75% efficient. Thus the maximum possible round trip efficiency is 75% (hydrogen production) x 60% (to generate electricity) = 49%. This makes it too intrinsically

[11] https://www.quora.com/How-much-electricity-is-needed-to-produce-hydrogen-from-water

[12] https://www.quora.com/How-many-kWh-can-you-get-from-burning-1-litre-of-hydrogen-gas

inefficient for use in electricity generation, so the place of hydrogen is in the gas grid and for fuel cells (50-60% efficient[13]).

FES 2020 envisages most hydrogen coming from methane reformation, and only a minority from electrolysis in all its forms.

- Methane reformation adds enormously to total system cost, not only due to the need for CCUS (assumed to be 95-97% effective a very high and expensive figure: see the section on CCUS) to be added to each plant, but also to the need to build BECCS to balance out the residual emissions; it is therefore an impractical and (if priced correctly to include consequential costs) excessively expensive solution for he energy transition.
- The efficiency of electrolysis is forecast to increase from 70% to 80% by 2050 (FES 2019 footnote 26, p103). The currently prevalent method of hydrogen electrolysis is PEM, though this is limited in cell size and by the service life (and cost) of the membranes. There are a number of developments in large-scale hydrogen production that should be backed, as they do not carry those disadvantages and are much more scalable and cost-effective.
- In the ST scenario, most hydrogen is expected to come from much less (currently 54%) efficient BECCs processes.

It is worth questioning the figures relating to hydrogen production: most of the input energy is added to gas demand rather than to electricity demand, whereas it should be added to the latter.

FES assumes that most electrolysed hydrogen is from sea water, so they add in the costs of desalination. However a number of organisations are working on viable ways of electrolysing sea water without prior desalination, which would greatly reduce its capital and operational costs and thereby make it very much more competitive in relation to methane + CCS and to blue hydrogen (re-forming + CCS).

Flexing electrolysis is envisaged to balance the intermittency of electricity supply with the variability of demand in the two scenarios which envisage massive growth in the use of hydrogen. Apart from the natural limitations of doing so, this assumes that doing so would not make the hydrogen prohibitively expensive. In reality, such flexing would require increasing electrolysis capacity by 2.5 times at best (when connected to offshore wind) and 6 times at worst (for solar connections); the average would be between the two. And given the inherent efficiency of electrified processes (e.g. heat pumps as compared with gas boilers, allowing also for the inefficiency of electrolysis), 70% efficient large-scale long-duration electricity storage is much more cost-effective and would require less intermittent generation. Indeed, the storage could be configured to deliver >80% total electricity output, to power the expensive electrolysis equipment as baseload.

[13] https://www.hydrogen.energy.gov/pdfs/doe_fuelcell_factsheet.pdf using Google's cached version as the original had moved

Hydrogen imports figure in all scenarios. It may well make sense to generate hydrogen using (for example) Saharan solar power. However its import only makes sense if fed into the gas grid, which is only the case in two scenarios. Its transportation emissions need to be accounted for. And, as we can (using wind) be self-sufficient quite cost-effectively in comparison with such imports, it makes sense to be so.

Hydrogen generation is a different matter. The process

Renewables => electrolysis => storage => generation in turbine

is intrinsically inefficient, with a maximum theoretical efficiency below 40%; current efficiencies barely surpass 20%. The capital and operational costs of such a system are vastly higher than those for 70% efficient large-scale long-duration storage, and so hydrogen generation should not be included.

Diverse Notes on Hydrogen

Hydrogen carries about ⅔ the energy per unit volume as gas, so the full gas network is likely to be needed even with electrification of significant parts of its uses.

National Grid assumes that direct electrolysis from wind will take place offshore on the grounds that it will be cheaper to pipe hydrogen than to provide a grid connection. We find this questionable in itself, and in consideration of (a) the number of underwater hydrogen pipe joints that would be needed and (b) the maintainability of this equipment in deep water. However this debate is largely immaterial: industry will use the more cost-effective methods when the time comes, and the method has little effect on these forecasts.

Bio-Energy

Throughout the report, bio-energy figures very strongly whether as a source of electricity or (with CCS) a means of deriving negative emissions to balance out hard-to-decarbonise sectors such as aviation.

Bio-energy suffers from intense competition with food for the growth of its feedstock. This makes it questionable whether sufficient power stations can be fuelled in the medium and long term.

The analysis of BECCS (bio-energy with CCS) appears to ignore the adverse effect of CCS processes on the bio-energy power station – see CCUS section for more detail.

And bio-energy is assumed to be a zero-emissions fuel and process. This ignores the emissions in farming the crop, processing it and transporting it. The contention (p61) that bio-fuels “are energy dense and easy to transport in compressed forms” assumes a high degree of processing whose emissions are not accounted for[14].

[14] https://uk-air.defra.gov.uk/assets/documents/reports/cat05/Carbon_factors_for_biofuels_final.pdf

Indeed, transportation elements are increasing sharply[15]. The assertion p62 that UK growth of feedstock will directly increase imports of food, so total transportation emissions would continue to rise just as fast as if the feedstock were imported.

Nuclear

Expectations of new nuclear power stations in the medium term are now realistic: in all scenarios, only one by 2030. ST and CT scenarios then have large build-out programmes which don't look very achievable in the current legislative climate, with an additional 9.5 or 5GW respectively by 2037, both exceeding 10GW additional by 2047. While significant amounts of this are expected to be Small Modular Reactors, the majority is expected to be large transmission-connected plants. While this is achievable, it is politically questionable[16].

In the LW scenario, no further nuclear plants are opened. It is the author's view that there should be some further nuclear plants for the reasons above (a further 10-20GW is of substantial economic and grid-reliability benefit even if politically unlikely), and that there will be some SMRs at least.

As a rule of thumb, multiplying generation de-rating factors by storage efficiency, 1GW nuclear is equivalent to:

- 3GW offshore wind plus large-scale long-duration storage;
- 4GW onshore wind plus large-scale long-duration storage;
- 6-10GW solar wind plus large-scale long-duration storage.

Note that these figures are greatly reduced if the renewables are supporting variable demand, which suggests that the most efficient energy transition would envisage a large nuclear build-out for baseload demand, with renewables and large-scale long-duration storage supplying variable demand. But to achieve this, the methodologies for valuing and charging of different technologies must change radically, to include consequential system costs as well as the full cost of emissions which range from

[15] FES 2020 p61: "there has been a rapid rise in imported biomass from around 11 TWh in 2008 to 40TWh in 2017."

[16] Just to illustrate this, Hinkley Point C was first proposed in the 1980s, winning planning permission in 1990 but dropped in the early 1990s as being too expensive at £1.7bn (https://en.wikipedia.org/wiki/Hinkley_Point_C_nuclear_power_station#1980s_PWR_proposal). The current 3.2GW plant was approved in 2007 for commissioning by 2017 (http://www.telegraph.co.uk/business/0/hinkley-point-c-new-nuclear-plant-timeline-of-the-story-so-far/). The latest delay puts the forecast commissioning date as 2027 and cost at over £20bn and £30bn subsidies through electricity bills (http://www.telegraph.co.uk/business/2017/07/03/hinkley-nuclear-costs-climb-almost-20bn-start-delayed/) – the scenarios expect it to come on stream in 2026, a year ahead of current expectations and without provision for any further schedule slippage. And all but one current nuclear power stations should retire by 2030.

$60 to above $240 per tonne[17]. This would, incidentally incentivise intermittent generation to pair with storage, to improve the value of their electricity as well as to reduce grid connection costs and usage charges.

Interconnectors

The three Net Zero scenarios rely on developing lots of interconnector capacity: 22GW for ST, 25GW for CT and 27GW for LW. But interconnectors cannot be relied upon to deliver energy when it is needed because low-generation weather patterns and high-demand periods frequently coincide across large parts of Western Europe. At such times, because nearly all countries' energy transition plans depend on imports, there will be little or no availability of energy for us to import. Yet "*at peak times we expect GB to continue to be a net importer of electricity in most scenarios*".

When a question was raised about this in the web conference, the response is that there are periods when large volumes of renewably generated electricity can be transferred, supposedly "proving" the case. That answer is entirely beside the point: the issue is not the times when such transfers can take place, but when they cannot.

Brexit doesn't just introduce uncertainties with respect to imports and exports, but actually places a political imperative on our neighbouring grids to prioritise their citizens over ours. While in the EU, the European Court of Justice enforced the Single Market rules to ensure that all contracts are honoured. When outside these arrangements, enforcement of such contracts is difficult. Worse, it is highly unlikely that a foreign grid operator would be allowed to deliver on such contracts if any exports to a country outside these arrangements contribute towards black-outs and brown-outs domestically.

Note that the same applies to our exports: when we have surplus, so (frequently) will our neighbours…

This and other aspects of interconnectors are discussed in much more detail in Appendix C.

Carbon Capture, Use and Storage

Usage of captured carbon is at a very early stage of development, with some promising lines of development – however these are all at very early (mostly theoretical and laboratory) stages. And most of them result in the re-emission of the CO2 later on because it's put into products such as synthetic fuels which are later burned, and plastics which is later thrown away. The UK parliament has released a briefing on this[18]. Therefore usage does not carry promise of major CO2 emissions reduction in the near future, so the principal target for national emissions reduction

---

[17] See OECD analysis https://www.oecd.org/env/cc/37321411.pdf and UK government analysis https://www.gov.uk/government/collections/carbon-valuation--2

[18] https://researchbriefings.parliament.uk/ResearchBriefing/Summary/POST-PB-0030 ("CCC Report")

must remain CCS. And usage means are currently prohibitively expensive, though future developments may solve that challenge.

CCS is expensive and imposes inefficiencies on the host system, e.g. the power station. It is also not 100% effective (though the unstated assumption throughout is that it is 100% effective) and both costs and resultant inefficiencies rise exponentially as the percentage of carbon captured rises. For example, CCS increases coal burn by a quarter for the same power output[19], raising its levelised cost of energy to well above that of other generation technologies[20].

But the most neglected element of CCUS is its hazardous nature. It captures, transports and stores for millions of years a gas which is colourless, odourless, poisonous and heavier than air: any leakage (such as from an earth tremor or equipment failure) would cause an asphyxiating cloud which would roll over the ground wherever a light wind blows it, including over population centres, much like a World War 1 gas attack. Making large networks safe in decentralised installations would be virtually impossible, so it must be concentrated in clusters.

Emissions cannot be avoided in certain industrial processes such as the cracking of limestone ($CaCO_3$) into lime (CaO) for cement[21]: chemically, $CaCO_3 \Rightarrow CaO + CO_2$. CCS is necessary for such processes. But it is not necessary for power generation: renewables plus large-scale long-duration storage such as Storelectric's is cheaper, more efficient and more environmentally friendly. Even nuclear is cheaper than gas plus CCS. There may be benefits in building a few CCS power stations that piggy-pack on industrial CCS clusters, but elsewhere it is neither affordable nor sensible.

For such reasons, in June 2017 the Americans cancelled the Kemper coal gasification and CCS project when its capital cost for a 582MW plant exceeded $7.5bn[22], i.e. $12.9bn/GW. If the Americans can't get it up and running despite paying considerably more than Hinkley Point (which is £20bn for 3.2GW, i.e. £6.25bn/GW or $8.4bn/GW), then what hope do we have of doing so?

Gas Generation

P111: "*In all scenarios the primary role of gas generation is to provide flexibility and backing up variable generation output from renewables. Between 2025 and 2035*

---

[19] http://www.world-nuclear.org/information-library/energy-and-the-environment/clean-coal-technologies.aspx (see table 1)

[20] For American LCOE costs (UK ones are higher), see table 1b (p8): LCOE for CCS coal is $132.2 - $140 https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[21] This chemical reaction alone accounts for >4% of global emissions, over half of the total emissions (8%) from cement manufacturing, most of the rest being from heat input to the process: https://www.bbc.co.uk/news/science-environment-46455844

[22] https://en.wikipedia.org/wiki/Kemper_Project and https://www.smithsonianmag.com/smart-news/major-clean-coal-project-mississippi-shut-down-180963898/

annual running hours become very low in the net zero scenarios." While this may make sense in terms of providing dispatchable back-up electricity, it does not make sense on other grounds:

- **Economic**: if a power station is little used, it needs to recover all its overheads and operational costs over a very small number of MWh generated. As current remuneration for generation is largely a split between availability and utilisation payments, and utilisation will be very low, so availability payments will need to be very high indeed. Using other plants for this purpose which have other revenue streams also over which to spread their operational and overhead costs, such as large-scale long-duration storage, would be much more cost-effective. Indeed, the report states that "*We assume a combination of policy and market change to support the required level of investment in flexible generation capacity with low annual running hours*." These would be very expensive indeed.
- **Flexibility**: power stations only generate. Storage both charges (absorbing excess) and discharges, and therefore provides twice the balancing service of power stations. Moreover, to procure such services separately would potentially incur enormous additional costs: if the cheapest way to procure discharge is with generation, then separately charging (demand turn-up) is procured, then two separate plants need to be paid for, each amortising its operational and overhead costs over each individual contract – and the plant with the charging contract would have to discharge at some time too.
- **Grid Stability**: gas-fired power stations provide inertia while generating. Large-scale long-duration storage provides it also while charging. Storelectric's does so 24/7, whether charging, discharging or neither.

The one service that power stations can provide that most storage can't is an indefinite maximum run time. However Storelectric's plants have extendible durations – CCGT CAES indefinitely and TES CAES hybrid for a multiple of its normal operating duration – see "Flexibility – Storage Volumes – Stretching Storage Durations" below.

BECCS is projected to operate as baseload, not as flexible generation, for purposes of negative emissions and therefore cannot be considered for these purposes.

Large-Scale Long-Duration Storage

National Grid defines long-duration storage as over 4 hours' duration. On p112, "*It will be necessary to develop large-scale storage with longer durations to support the decarbonisation of the power system*." V2G is over-estimated by at least a factor of 7 (see above); there is little (1.1GW) potential for expanding pumped hydro provision. Batteries are too expensive, inefficient and short-lived, and are subject to critical materials shortages. Flow batteries are essentially swimming-pools full of concentrated acid (hazardous, expensive and environmentally unfriendly to make and dispose of) laced with scarce rare-earth metals. LAES is too small, expensive and inefficient, though benefits from not being geologically constrained (though the

current and, especially, future range of suitable geologies for CAES is very widespread). That leaves CAES – and especially adiabatic and other suitably efficient modern versions of it.

The requirement for large-scale long-duration electricity storage has increased over previous years' assessments to account for the Net Zero target, in which the power system is negative emissions by the 2030s. **Total storage needed is 23-40GW**, a quantity that only large-scale storage can provide. There is no statement as to the duration of such storage, but FES 2019 stated (consistently with the National Infrastructure Plan and the Technology Innovation Needs Analysis) that most of it needs to be long-duration. This increases to XXXX-XXXXGW taking into account the many other considerations contained within this analysis.

While it is true that "*types of storage with different durations are used in varying ways*", there is overlap and considering them service by service will greatly increase total system costs. If (for example) secondary frequency response and similar contracts all let to batteries, with only the less-remunerative longer-duration services available to long-duration storage, then that longer-duration storage would have to amortise its costs over a smaller revenue stacks and so put up its prices in comparison with what they would have been had such storage won the secondary-FR contracts too. The grid would therefore be paying for surplus assets, namely the dedicated secondary-FR assets in addition to the longer-duration assets. For a practical, simple and cost-effective solution, see Appendix D: A 21st Century Electricity System.

Flexibility

The Roles of Grids

The role of the transmission grid also changes somewhat: "By 2050 the level of decentralisation in all scenarios suggests the role of the transmission system may often be to transport electricity from one distribution network to another, rather than delivering from transmission connected generation to distribution networks." However this does not negate the need to have sufficient energy on the grids at all times – it just relocates the energy sources. Indeed, such supply from one region to another requires not only very large transmission grid capacity, but large excess capacity in each distribution grid in order to have sufficient surplus to export.

All distributed systems depend on the transmission grid for back-up during times of system stress (high demand and/or low renewable generation); the transmission grid may source such back-up from either its own directly connected assets or other distributed systems. However it must be borne in mind that such "times of system stress" often occur concurrently throughout the country and our neighbouring countries too, so there must be enough energy from dispatchable or baseload sources to power the entire system for the longest such periods – and maybe for

more than one such if they risk occurring before any storage will have been replenished.

Interconnectors are discussed at length in Appendix C; vehicle to grid (electric vehicles) and hydrogen are discussed above.Storage Volumes

FES 2019 identified a need, by 2050, for 20-28GW of "mostly long duration" storage to meet an 80% emissions reduction target. In FES 2020 p82, "the weather dependence of renewable generation means that much larger amounts of flexibility are required."

The total storage requirement of each scenario is:

- 21GW for Steady Progression, the do-nothing scenario;
- 23GW for System Transformation;
- 37GW for Consumer Transformation; and
- 40GW for Leading the Way.

This is a substantially increased recognition of need for storage. Very notably, even the do-nothing scenario requires 21GW storage; all Net Zero scenarios require 23-40GW, which should be increased because (details elsewhere in this document):

1. Interconnectors cannot be relied upon;
2. Hydrogen generation will not be as cost-effective or efficient as CAES;
3. Balancing intermittent generation by flexing hydrogen electrolysis is too costly;
4. The amount and duration of V2G storage is vastly over-estimated.

Taking these into account, the total need for storage in the UK is:
XXXX

The conclusion that "frequent oversupply of electricity generation will require an increase in flexible demand to avoid generation being curtailed" overlooks the fact that large-scale long-duration storage can provide such flexibility at lower cost, disruption and need for consumer engagement / behavioural change, and is therefore much more likely to be successful in achieving Net Zero.

Stretching Storage Durations

A major challenge to the potential for storage to replace other means of delivery flexibility is wrongly believed to be that "it is limited in the duration it can produce its maximum output for by the capacity of energy in the battery or volume of water in the reservoir". Both Storelectric's hybrid CAES technologies can be made extendible in duration fairly cheaply without sacrificing their zero-carbon natures.

Doing so reduces or even eliminates the much costlier and less efficient means envisaged within FES 2020 of supply-side flexibility: gas+CCS, hydrogen generation and biomass (and interconnectors, which cannot be relied upon) – and also greatly reduces the grid reinforcement and investment into grid stability that would otherwise

be required. Some biomass+CCS (BECCS) would still be required, but much less as there would be no residual emissions to negate from gas combustion or hydrogen manufacture by reformation processes; such lower volumes are much more feasible in consideration of other land-use needs.

Seasonal Storage?
One of the key flexibility challenges is the fact that most gas demand occurs in winter, for heating. While partly overcome in ST and LW, there remains a substantial seasonality challenge which some suggest should be addressed by seasonal storage of electricity and/or of hydrogen. All scenarios require at least 15TWh hydrogen storage (p102). Although such volumes of storage are very feasible, in our view they are unnecessary other than as a fall-back reserve: wind generates most in winter, so a greater proportion of wind output, combined with long-duration (4 hours to 2 weeks) storage would be the most cost-effective solution – and is deliverable with technologies available today, improving with imminent developments that do not have the uncertainties of major R&D. And the graph of stored hydrogen on p102, with stocks dropping to zero in late October, itself negates the case for using hydrogen for seasonal storage.

Accommodating seasonal demand fluctuations with wind-plus-storage would increase the requirement for large-scale long-duration storage by an estimated 25-50% beyond what is described above.

Global Storage Needs
Note that world total energy consumption is roughly:

- USA: 7.5 x UK
- European Union: 12.5 x UK
- World: 100x UK

and their storage needs will be scaled accordingly.

Storage Revenues and Mix

Revenue Stacks: FES 2019 (there is no mention of it in FES 2020) was correct that storage can support, and needs to access, multiple revenue streams (a “revenue stack”). This is one of the many unfortunate results of the mis-definition of storage as generation (for more such consequences, see Appendix E). Revenue stacks were easy to manage for all parties when each was only 3-4 services high; our storage can access 12 current services and more that are being developed, potentially 18-20 in all. The result is:

1. Huge administrative effort to bid on each and every stack every year or two;
2. A corresponding huge administrative burden on the System Operator side in running these auctions, selecting and managing these contracts;
3. A chance that each of them may fail to win, meaning:
   - Higher financing costs and hence higher bid prices,

- We need to add in another margin to ensure that we remain profitable even if we fail to win a given bid, or fail to win other future bids for other streams while this contract is in force,
- This uncertainty itself adds to the price;

4. Increasing complexity in the grid control room.

Moreover, the way in which contracts are being developed is leading to the most lucrative and easy-to-source services being auctioned to specialist plant. This creams off the top of the revenue stack, making it necessary to increase the price of the harder-to-source services that we can provide, in order to cover our costs and generate sufficient profits for investors. The net result is that while National Grid trumpets that the prices of these creamed-off services fall, in reality the total system cost of providing the full range of services rises.

A much cheaper methodology would be to let the harder-to-let contracts first, with the promise that all other revenue streams for which the plant is cost-effective will be awarded to it too. Then only the remainder of the next-hardest-to-let contract is auctioned. In effect, this is how the main market works, with the TSO only auctioning the balancing and ancillary services that are left over after the main generation contracts have been let by others. For more information, see Appendix D, A 21st Century Electricity System.

The review is also correct that the benefits of storage are compounded when integrated with other projects such as intermittent generation or interconnectors. And it is true that there is a substantial need for storage that is unconstrained in location, for distributed roll-out to provide localised and short duration balancing services.

The mix considered by FES 2019 is batteries at both transmission and distribution scales, vehicle to grid batteries (above), DSR (below), pumped hydro and interconnectors. CAES is mentioned only in passing, thereby greatly adding to potential costs not only in generation, balancing and imports, but also in energy security and national balance of payments.

Batteries are optimally up to 20-40MW with optimal durations of 1-2 hours. Doubling either size or duration adds roughly 85% to capital costs; doubling the size or duration of larger scale technologies adds much less – for adiabatic CAES[23] the figure is around 30%. The larger scale technologies are not efficient at scales below ~2-MW (or 5MW for LAES), and they all provide true inertia rather than EFR, so they barely compete with batteries.

It is possibly in recognition of this lack of vision as to how batteries can support the volumes of flexibility required that there is almost no further discussion of them, despite the large increase in storage capacity required in all scenarios (p106): how they can provide the requisite volume of energy is not addressed, as batteries

[23] CAES = Compressed Air Energy Storage, see www.storelectric.com
LAES = Liquid Air Energy Storage, see www.highviewpower.com

cannot store enough energy (size x duration) due to their limited size and even more limited duration. Various studies also suggest that they have a much more limited life than advertised, especially if used in quick bursts for the faster balancing and ancillary services[24] which tends to be their main justification and business case. Other studies show that they are much less efficient (grid-to-grid) than advertised[25].

Pumped hydro: It is curious and highly indicative of past interactions that, despite claiming not to "back winners", National Grid identifies pumped hydro rather than large scale long duration storage which could also be provided by CAES, adiabatic CAES and LAES systems, all of which have lower costs, greater geographical flexibility, better proximity to both generation and demand, lower environmental impact (they don't flood valleys) and larger overall potential. Despite all these advantages, little effort has been made by BEIS, Ofgem and National Grid to support the development and construction of first-of-a-kind plants of these UK-developed technologies, thereby impeding their development against their corporate imperatives to encourage the development of new technologies and solutions to known problems. Equality of opportunity and a level playing field is sought.

Faraday Challenge: As an aside, it is very curious why, having taken the excellent decision to support the development of a new industry in electricity storage, the government decided to waste £246m on the Faraday Challenge, when:

1. The UK is playing 20-30 years' catch-up in lithium technologies;
2. We lead the world in other storage technologies, if only we can have some support to build commercial first-of-a-kind plants;
3. There is no battery manufacturing in the UK;
4. Of the 40-60 gigafactories that have been announced, not one of them in the UK (though in 2019 the government floated the idea that it would be nice to build one here), and there is no room for more as that many would already deplete global resources of lithium in 2-10 years (see Electric Vehicles, above).

The Politics of Storage

Yet energy storage (both grid and battery scale) and DSR can help deliver the energy priorities of every single significant national political party:

1. By providing a market for nearly every MWh generated by renewables, it reduces or eliminates the need for renewables subsidies – assuming fossil fuels are not subsidised, thereby reducing the subsidies part of both energy prices and tax bills;
2. By supplying peak demand, the most polluting, expensive and unprofitable fossil fuelled power stations can be not only switched off but also (if we have

[24] E.g. 'Battery energy storage efficiency calculation including auxiliary losses: Technology comparison and operating strategies, authors F.M. Gatta ; A. Geri ; S. Lauria ; M. Maccioni ; F. Palone ' (available with a subscription to the IEEE www.ieee.org) and also https://www.energiforskning.dk/sites/energiteknologi.dk/files/slutrapporter/bess_final_report_forskel_10731.pdf

[25] http://www.networkrevolution.co.uk/network-trials/electrical-energy-storage/ Electrical energy storage cost analysis paper – see round trip efficiency including parasitic losses, chart on p6

enough storage capacity) demolished, benefitting energy prices, the environment and the profitability of the generating companies;

3. By absorbing power during peaks in renewable generation and troughs in demand, the remaining power stations can operate as baseload, again benefitting energy prices, the environment and the profitability of the generating companies;
4. By working with both non-dispatchable power generation and the grid as a whole, storage and DSR can smooth the transition to a fossil fuel free grid;
5. By enabling non-dispatchable generation to supply variable demand at all scales, storage and DSR enable the transformation of transportation, heating and industry to clean electricity sources;
6. By relying on locally generated electricity, storage and DSR can enhance energy security and grid resilience both nationally and regionally.

Combined with renewable power generation, these can deliver:

7. Falling energy prices, as the input power is free;
8. Vastly reduced pollution and emissions; and
9. Energy security, as they are all generated from local resources like wind, sun, tide and waves, rather than imported fossil fuels or interconnected electricity.

Demand Side Response

Industrial and Commercial DSR

FES 2020 contends that in all Net Zero scenarios, available Demand Side Response (DSR) in the commercial and industrial sector greatly expands from the ~1.2GW at which it has remained static for 5 years now, in roughly linear growth to 8-13GW. At least ⅔ of that DSR is fossil fuelled back-up generation which will become impossible under Net Zero, so existing capacity is ~400MW. No mechanism for such a dramatic (multiplying by 20-52 times, linearly achieved in 30 years) increase is established, and there is little development visible which would deliver it.

Residential DSR

FES 2020 assumes that eventually 80% of consumers will change their behaviour to change the times at which they consume energy. However Smart Meter advertising claims that doing so can only save up to 2% of bills, i.e. ~£20-40/year. Such savings seem to be at least an order of magnitude too low to engender such behavioural change. Therefore, very roughly, we believe that, even with increasing incentives through time-of-use tariffs, demand response including flexible vehicle charging times (see next sub-heading) will be halved. (V2G reduces by a factor of 7, above.)

There is also a huge roll-out of residential thermal storage proposed for all three Net Zero scenarios, starting in 2022. That delay is sensible as it would require major government incentives. While it is true that 25% or so of households already have thermal storage in the form of hot water cylinders, they have been removed from 75% or so of homes in favour of combi boilers. Unfortunately their space has been filled with other things, and the homes in which they are fitted tend to be the smaller ones, so uptake of thermal storage is questionable.

Smart Charging of Vehicles
Smart charging of electric vehicles is the biggest reasonable form of DSR. This differs from V2G (see above) in that V2G is based on feeding surplus stored electricity back into the grid, while smart charging times its charging to minimise overall grid demand while delivering the requisite state of charge at the required time. The two actually conflict with each other: although they can use the same equipment, the act of smart charging will reduce the amount of energy available for V2G at peak times by delaying re-charge.

Smart charging effectively delays the re-charging of vehicles until after the evening peak of demand. This will have a multi-GW levelling effect on the demand curve at minimal system cost. But it cannot delay it too far: it takes substantial time to charge vehicles. Fast charging is of no benefit in this: (a) it requires the same amount of input energy (actually, a bit more as losses increase) to be put into the vehicle by the same time in the morning, so it would just mean that (for example) houses 1-6 take it in turns to charge their cars 6x faster instead of all charging simultaneously at the slower rate which, at neighbourhood level, is no different; and (b) fast charging reduces battery life significantly.

System Costs

Existing Subsidies

There are many subsidies hidden in the electricity system. For example,

- Interconnectors rely on the double subsidy of cap-and-floor contracts and zero grid access charges;
- Interconnectors also provide a UK-financed subsidy to overseas generators owing to their lower grid access charges and carbon prices, and the fact that the difference between these and the UK versions are not charged on import;
- Nuclear power relies on a very highly priced cap-and-floor regime;
- The total cost of the balancing and ancillary services market has increased by ~£1bn between 2010 and 2017, which represents additional system costs for balancing intermittent renewables without sufficient large scale long duration storage;
- The £1bn+ Capacity Market seems to be a subsidy dressed up as a market, to keep fossil fuelled power stations in operation to balance intermittent renewables;
- A negative subsidy (i.e. unwarranted cost) is imposed on storage by triple charging (to import and to export, plus the cost embedded within the price of the purchased electricity) which is currently proposed to reduce to double charging, still an unwarranted commercial disadvantaging.

The balancing/ancillary markets and Capacity Market subsidies alone are already over £2bn p.a. and expected to double within 5 years and to keep on increasing[26].

The two compliant scenarios rely on 15.75GW nuclear power. This is proving to be one of the most expensive energy sources available. It also relies on 8.3GW CCS, analysed above. It also relies on 19.7GW interconnectors which are only viable with. In contrast, Storelectric's CAES has a cheaper levelised cost of electricity than a gas-fired peaking plant and can therefore balance the entire system cost-effectively and (on a level playing field) without subsidy.

The electricity system can only deliver cost-effective energy to UK consumers if the playing field is levelled.

Affordability

While policy makers talk about energy cost, they mostly focus on its price. These have become divorced from each other, with cost (including both overt and covert subsidies) rising as fast as price (£/MWh wholesale) falls. Already more than half of most commercial bills is made up of non-price levies and costs; this should be under one-quarter, preferably <20%, to pay for transmission and distribution costs alone, and to penalise anti-social behaviour such as excessive consumption of fossil fuels.

Contract Length

This focus on lowest price today and in the near future is the driving force behind the current regulatory structure. As a result, another tilt in the regulatory playing field is the short term nature of all contracts. This favours investments that have a short pay-back time, and hence those that have a short operational life and/or small scale.

- The cheapest way to deliver a 2-year contract is to patch up a fully amortised plant for an additional 2 years' life.
- Following this contract, it is repeated; only the plant is older, more polluting, more expensive to patch up and maintain, and less reliable.
- This repeats at ever increasing cost until the plant dies of old age.
- Then electricity needs to be imported or new plants built with subsides.
- The cheapest way to deliver a 15-year contract is with a new plant.
- The total cost over 15 years is less under a 15-year contract than under 7½ x 2-year contracts, and in the meantime sufficient capital investment has been put into new plant to keep the system young, without subsidy, with benefits in security of supply (both definitions), reliability and cost.

Again, the electricity system can only deliver cost-effective energy to UK consumers if the playing field is levelled.

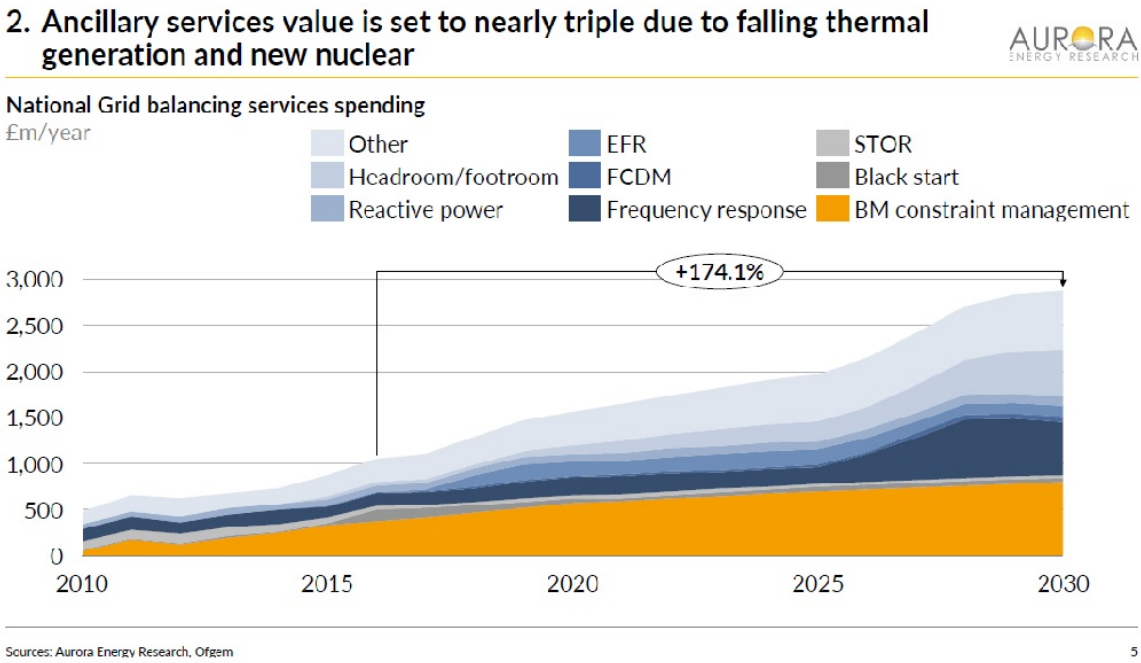
[26] More details available in a Storelectric white paper Curtailment: the Tip of a Growing Iceberg, available on request

Costly Responses

In response to these shortfalls, National Grid is taking increasingly costly measures such as creating the Capacity Market in which, according to a recent government consultation document[27], "Two CM auctions have now been held, for delivery in 2018/19 and 2019/20 respectively. Whilst, given the target levels that were set, the auctions procured relatively little new capacity…" for about £2bn.

Added to that, the Winter Outlook Report 2015 states that to cope with narrowing markets, National Grid "developed a set of new balancing services (NBS) to help us to manage the uncertainty and tightening margins over last winter. … Demand-Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR)". "The total costs incurred in the procurement and testing of the new balancing services was £31.2m." This total is likely to increase in future years: "On 3 June 2015, we announced the procurement of the 2.56 GW of additional electricity reserve for the winter 2015/16", compared with the 1.05GW purchased the previous winter.

In FES 2017, National Grid stated that there will be "a growth in balancing tools and technologies", but admits that "What technologies will be utilised has yet to be established by the marketplace"[28]. This must grow: "As intermittent and less flexible generation grows at transmission and distribution level, the ability to flex generation and demand is becoming increasingly important"[29]. This supports Aurora's analysis in 2016, whose figures have largely been borne out in practice:



[27] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf

[28] Spotlight, p63

[29] Sources of Flexibility, p64, first sentence

Since then, further market mechanisms have also been created, adding to the costs of maintaining the system, such as Supplemental Balancing Reserve, Enhanced Frequency Response and Demand Side Top-Up. It appears that additional patches or sticking plasters are being added to a worn-out regulatory framework at ever-increasing rates, tackling the symptoms of the problem rather than its causes, the largest of which is the system-wide loss of inertial generation and load.

Worse, renewables have been allowed to bid (albeit with huge de-rating factors) for Capacity Market Contracts. Since the CM exists to ensure back-up for renewables, they can't back themselves up, so any amount of de-rating below 100% is a logical non sequitur.

And finally the CM has been subverted: 85% of the last T-4 contracts were let as 1-year contracts, i.e. a second bite of the T-1 cherry, which destroys the market's purpose in financing the construction of new plants.

COVID-19 Lockdown Developments

During the recent Lockdown, demand was suppressed during a sunny and windy period, to the extent that renewables generated a proportion of demand that had only been expected in the 2030s. National Grid spent £10-30m per day on measures to ensure sufficient stability in the system (which could have been delivered much more cost-effectively by 2-4GW of Storelectric's plants), and put out a forecast that by the 2030s such measures would cost over £1bn p.a. It is notable that these measures involved turning on/up gas-fired power stations, most of which will have closed by the 2030s; one wonders where the grid would source such stability services if not from large-scale long-duration storage. For more details, see the appendix The Lockdown: A Partial Test of the 2030s Grid.

Revenue Stacking

Large scale long duration plants of most types rely on stacks of diverse revenue streams to be profitable. This sticking plaster approach to the challengers of the energy transition means that each issue is turned into a contract / revenue stream, one at a time, as it is discovered and quantified. The largest and most remunerative ones (e.g. EFR) are contracted first, because those are the most urgent and greatest need.

Because these needs are addressed individually and with short term contracts, short-lived and small-scale solutions (e.g. batteries) are used to deliver them. Long-lived and large-scale solutions that address many such challenges, and especially those which tackle the root cause of the problems, cannot be financed under short term salami-sliced contracts: they need an entire revenue stack. But the salami slicing, sticking-plaster approach creams off the most remunerative parts of the revenue stack rendering the remainder of that stack less profitable, and therefore building in a need for higher overall prices – i.e. subsidies hidden within the markets.

To minimise the overall system cost and maximise its security of supply, and to do these over the short, medium and long terms, a better approach is to address the causes of the problems, principally the need for clean (i.e. low or preferably zero emissions) inertial generation and load. Contracts for these should be let for a suitable time. They should then be contracted to deliver whatever other services they can deliver cost-effectively to the system, thereby giving them their entire revenue stack without any increase in price, without any overt or covert subsidy. It is only after this is complete that shortfalls should be evaluated and let in narrow, shorter duration contracts.

Failing to minimise overall system cost in this way will not remove the business case for large scale long duration renewables, because the need will remain. The main effect of such failure is to increase its cost to the system.

OFGEM Recognition and Actions

While Ofgem have expressed the need for storage in the past, currently all storage requires special consideration. This vastly increases regulatory uncertainty for investors and developers alike.

Recent pronouncements from Ofgem and BEIS are quoted in Appendix D.

There is no regulatory category for energy storage, so storage equals consumption plus generation, neither of which is related to time or demand. This means that:

1. For grid connection applications, if DNOs propose the storage (e.g. Leighton Buzzard, Eigha, Orkney), it is deemed to create capacity; if anyone else proposes it, it is deemed to consume capacity;
2. Although charging and discharging are countercyclical and will largely be determined by the Grid's / DNO's needs, grid connections must be paid for that are sized for maximum charging during peak demand and discharging during trough demand, adding ridiculous and unnecessary costs to the project (unless the DNO is proposing it…);
3. DNOs are prevented from investing in storage over the 5MW waiver;
4. Although National Grid can invest in interconnectors, which take and return grid power, they cannot invest in storage (or even research into storage technologies via NIA / NIC or other mechanisms) even though they and the consumer would greatly benefit from it;
5. There can be no contracts for storage services;
6. Electricity has to be purchased and sold regardless of when balancing services is wanted, therefore if the services are wanted off-peak using energy stored at other times, there will be a loss – though this will only become a substantial issue when availability of dispatchable electricity drops to levels below the levels of off-peak demand variability, and therefore not for more than a decade.

Ofgem have proposed to define storage as a sub-set of generation, which is fundamentally wrong – they are more like interconnectors:

- Neither technology generates electricity;
- Storage moves electricity in time, as interconnectors move it in location;
- Therefore storage is a grid service / feature, much as interconnectors are.

National Grid Recognition and Assessment

The Grid recognises that "Electricity storage could be significant for the future balancing toolkit. It has the potential to offer valuable services to the SO [System Operator], broader industry, and ultimately the end consumer." (FES 2015) Even on this restricted remit, National Grid assesses every area of policy and action relating to storage as either very poor ("red") or inadequate ("amber"):

- Policy and regulatory developments are amber, with a regulatory definition of storage and other regulatory changes promised but not yet delivered. There remain many issues with levies and charges (including double charging of storage with the Levy Control Framework and Climate Change Levy).
- Commercial development is amber due to lack of multiple clear revenue streams, or price signals – especially Time of Use tariffs, though they omit Time of Use generation contracts which would provide a much stronger signal. The outlook is improving, with Demand Turn Up and other enhancements, but these are mostly focused on small scale storage and there are issues with stacking some revenue streams at scale. There is no business model to evaluate network reinforcement deferral or other benefits.
- Technological developments are amber because the levelised cost of electricity of batteries and flywheels is too high. There are improvement in Li-ion battery storage costs, but they don't see other technology improvements – still failing to see or support Storelectric's more cost-effective and better-designed system.
- System need (i.e. how well the system is coping without storage) remains amber, with good response to the new EFR service being more than balanced by growing flexibility challenges and the uncertainties of an ever-changing regulatory framework. In the 2015 report this section then describes how storage can match non-dispatchable supply with variable demand, and identifies a need for storage to "provide a cost-effective solution to that need" – but this year's assessment gives no thought at all to larger scale storage.

National Grid concludes: "Storage has the potential to be a significant contributor to the future flexibility requirements of the system. As storage becomes more cost-competitive and the identified barriers are removed, we anticipate a significant rise in new storage deployment."

Energy Industry Actions

Until now, the renewable energy industry has been balkanised, with each industry association and consortium pressing for special treatment, subsidies, market

instruments etc. The result is increasingly costly and incoherent, and provokes counterproductive reactions like the creation of the Capacity Market.

Since the politics means that we should be pushing on an open door, the renewable energy industry (generation, storage and DSR) should get together and propose one single, viable and affordable road map that outlines a single, coherent set of actions that government and grid should take in order to achieve one of a small range of potential solutions.

The potential solutions should include maximum and minimum scope for each technology in the mix. The technologies should include, for the electricity industry:

- Onshore and offshore wind;
- Rooftop and farmed solar (focusing on wide scale rooftop deployment);
- Tidal range and flow;
- Biomass (limited due to other future demands on farmland, globally);
- Wave;
- Storage at every one of the five scales outlined above;
- Demand side response (up to 3-5% of maximum demand).

This should be backed up by a comparable portfolio of technologies, including:

- Storage at all 5 identified levels (domestic, local, area, regional, national);
- Flywheels;
- Demand side response;
- Interconnectors.

In order to be both comprehensive and coherent, this road map (and also Future Energy Scenarios) should also include actions that will need to be taken to accommodate the transfer from fossil fuels to renewable electricity of:

- Heat (especially through heat pumps);
- Transportation;
- Industry.

The list of actions included in the proposal should include:

- Support for research and early stage development;
- Support for later stage development, proportional to the scale of solution being provided (e.g. more finance for a tidal or grid-scale storage demonstrator than for a heat pump or domestic-scale storage demonstrator);
- Support for first deployments, on a sliding scale, e.g. full CfD for 100% of the capacity of the first-off, decreasing linearly by 10% of capacity and 5% of price for each subsequent one, with particular designs to be suited to need –
    - Incentivising the generation of power when it is wanted,
    - Recognising input costs as well as output costs,
    - Recognising the particular features of each group of technologies;
- Serious carbon tax or carbon permit price, matched by corresponding subsidies to prevent serious damage to the fuel poor, and to industry – but the

subsidies must not be matched with consumption, in order to incentivise economy and the development of alternatives;

- A government office in charge of all this, with sub-offices for each part of it;
- Regulatory definition of storage (see Appendix E), so that Grid and DNOs can invest in it, so its countercyclical operation and grid control of energy flows must be taken into account during any connection study / action, and so there can be recognition that storage requires both power purchase and power sale;
- Regulatory definition of a way in which Grid and DNOs can act purely as carriers between two private contractors, e.g. major generation and storage, storage and major consumption, major generation and major consumption.

BEIS / Ofgem / National Grid Actions

The only ways to avoid such a situation would be to invest in either lots of new generation (if gas-fired, this would be in breach of international treaty and moral obligations that would survive Brexit), or massive-scale storage. The latter will enable us to meet our emissions obligations by enabling us to use renewable generation to power not only peak demand but also much baseload demand. To do this without any ongoing subsidies would require:

1. Long term contracts (15 years) for energy, which would actually deliver cheaper electricity over their term than a succession of 1- and 2-year contracts, and therefore pay for themselves –
   - If 1/3 of all contracts were let for 15 years, solely for new plant, then that would presume a plant life of 45 years, which is about right,
   - If a second 1/3 of all contracts were let for 7.5 years, solely for plant which either is new or has received major capital investment (e.g. overhaul, upgrade), then this would ensure plant efficiency and security of supply,
   - If the final 1/3 of all contracts were let for 2 years with all plants being eligible, then this would ensure that all have markets and prices would not rise excessively;
2. Incentivise environmental performance without subsidies, by using contract length:
   - A zero emissions plant receives the full contract length,
   - A plant with emissions equivalent to a coal-fired power station is eligible for half the contract length,
   - There is a linear relationship between these two extremes;
3. Incentivise new technology introduction (the construction of a first-of-a-kind [FOAK] plant), again without subsidy, by means of enforceable letters of intent –
   - The letter would say that the System Operator will buy the services that the plant will offer when it can offer them (so as to allow for long grid connection times) under the contracts on offer at the time and at the prices on offer at the time (i.e. no subsidy or special contracts) to a maximum of 25% of any given contract type (so as to avoid market distortions),
   - Such letters are issued prior to planning and grid connection applications (the intention of these letters is to guarantee a market and thereby bring in

private sector investment, without subsidy, to do those as well as to build the plant),

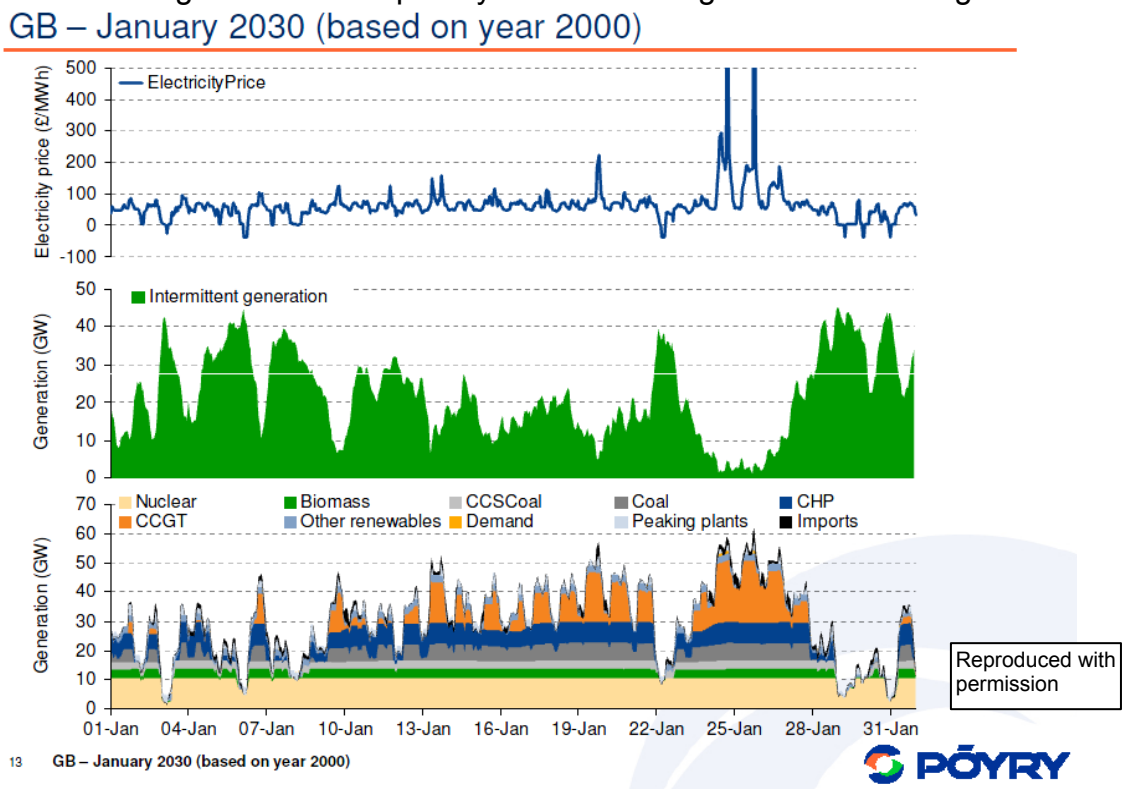
- Such letters remain valid for as long as there is significant progress (including seeking investors),
- Because no subsidy is involved, only plants that expect to be competitive would call for such subsidies,
- If the government were to wish to support R&D (e.g. via InnovateUK), then it could do so, but this would be a separate decision – and neither the letter nor the support should exclude the other,
- For each technology, do this for one FOAK at distribution scale and one at transmission scale, provided that the two sizes were at least a factor of 5 (maybe 10?) different in size, because such changes in scale carry their own challenges;

4. Establishing in law a regulatory definition of storage to be based on that of interconnectors, to avoid double charging in both capital and operational costs for grid connections, and to enable contracts to be let for storage services (see Appendix E for more details);
5. Phasing out of subsidies to fossil fuel generators (e.g. the Capacity Market);
6. Preferably, a re-design of the market to base it around renewable generation and storage with some nuclear baseload, rather than today's market structure which is essentially based on nuclear and coal baseload with gas variable generation, and patch after patch (new contracts and rules are being introduced at an ever-increasing rate) to cope with a modern generation mix.

Appendix A: Poyry and TINA Analyses of the Challenge

The Scale of the Problem – Poyry

The graph below superimposes the actual wind pattern of January 2010 on the forecast generation mix and demand pattern of 2030 on the assumption that all forecast wind generation has priority access to the grid over all other generators:



Reproduced with permission

The following results stand out clearly:

1. When the wind blows strongly, even baseload generation (which should never be turned off – mainly nuclear and coal) has to be turned down / off – six times during one month for nuclear. When demand is lower (e.g. in summer), this could happen more often. Instead of switching them down / off, the system is made much more efficient if that amount of wind energy is stored.
2. Even variable generation (such as gas) operates much more efficiently and with lower emissions if operated as baseload – like driving a car on a motorway rather than round town. This is only achieved if there is sufficient storage. Incidentally, this is why traditional generators are currently going through very difficult financial times: while their revenues are reduced (due to being switched off / down so much), their costs are increased (wear and tear, efficiency of burn, average cost of fuel – because a greater proportion of their fuel is being bought at peak).
3. The scale of variability of wind production is 60GW. Therefore to absorb such variation, 60GW storage would be ideal. However some of this can be made

up by, principally, Demand Side Response and batteries – each to an economically feasible level of 2-3GW.

4. For long periods (e.g. from late December to 10th January, and from 29th January onwards, in this example), there is highly fluctuating wind generation that remains almost continually above 30GW, meaning that the amount of energy needed to be stored is enormous (up to 5TWh) in order to make other power stations operate efficiently and with minimal pollution.
5. This power is needed when the wind doesn't blow, e.g. from 24th to 27th January. Such non-generating weather systems can stand over most of western Europe for up to 10 days at a time, every three years (estimated by us at 5-10TWh) – and more often for shorter periods and/or smaller regions. Therefore, if peaking and back-up power stations are to be shut down completely, at least 10 days' non-baseload energy needs to be stored.
6. And all this ignores the effect of solar, wave and tidal generation….

So the scale of the problem is 60GW, 5-10TWh. But in the shorter term, the balancing requirement for variable demand is 30GW, of which about 3GW is currently being met by pumped hydroelectric storage.

Scale of the Problem – TINA

Another analysis of the problem, the Technology Innovation Needs Analysis[30] by the Low Carbon Innovation Co-ordinating Group (LCICG), which is the biggest inter-departmental group in the British Government's civil service, identifies that Britain requires 27.4GW of storage (in the range of 7.2 to 59.2GW), with a capacity of

Chart 2 EN&S technology deployment scenarios

Area	Sub-area	Units	2020 deployment		2050 deployment	
			GW	GWh	GW	GWh
Storage	Pumped hydro	GW or GWh	4.3 (3.1 - 6.6)	21 (15 - 33)	8.2 (3.3 - 17.3)	41 (16 - 87)
	CAES		1.8 (0.2 - 3.8)	9 (1 - 19)	7.1 (0.7 - 15.3)	35 (4 - 76)
	Sodium-based batteries		0.5 (0.1 - 1.1)	2 (1 - 6)	1.9 (0.5 - 4.6)	9 (3 - 23)
	Redox flow batteries		0.3 (0.1 - 0.9)	2 (1 - 4)	1.4 (0.4 - 3.5)	7 (2 - 18)
	Lithium-based batteries		0.4 (0.3 - 0.9)	0 (0 - 3)	1.7 (1.2 - 3.6)	2 (2 - 10)
	Flywheels		0.1 (0.1 - 0.1)	0 (0 - 0)	0.5 (0.3 - 0.6)	0 (0 - 0)
	Supercapacitors		0 (0 - 0)	0 (0 - 0)	0 (0 - 0)	0 (0 - 0)
	Thermal-to-electric storage		1.7 (0.2 - 3.6)	8 (1 - 18)	6.7 (0.8 - 14.3)	34 (4 - 72)
	Total		**9.1 (4.1 - 17.1)**	**43 (19 - 83)**	**27.4 (7.2 - 59.2)**	**128 (31 - 286)**

128GWh (31 to 286GWh). This is 5 hours' storage at rated capacity, coinciding with the duration of the winter evening peak: almost no grid-connected battery in the world has more than 2 hours' storage because it is not cost-effective.

---

30 https://www.carbontrust.com/resources/reports/technology/tinas-low-carbon-technologies/ Energy Networks and Storage report chart 2 p9 which splits it down into various technologies without considering the costs of doing so (batteries of all kinds with the required 5-hour durations and pumped hydro are much dearer than CAES) or availability (they exceed the country's pumped hydro potential), or the availability / practicality of the technology (thermal-to-electric stopped when Isentropic went into administration in 2016 http://www.eti.co.uk/programmes/energy-storage-distribution/distribution-scale-energy-storage, long before FES 2017 was published, despite £14m investment by ETI, http://www.eti.co.uk/news/eti-invest-14m-in-energy-storage-breakthrough-with-isentropic).

This analysis only looks at supporting the country's currently forecast variable demand, assuming that baseload demand will continue to be supplied by nuclear and gas plants. Therefore if nuclear is to fail to materialise in sufficient volume (which looks increasingly likely), and we cannot increase the gas generation lest we exceed our treaty obligations on emissions, this storage requirement must be increased greatly to accommodate baseload generation.

Even taking the 27.4GW figure at face value and looking at cost-effective developments only, we can expect it to be made up of (additional to what was in place at the publication of the report) 2-3GW (2-3GWh) demand side response, 2-3GW (2-3GWh) batteries, 8-12GW interconnectors and 2GW (20GWh) total of all existing pumped hydro planning applications. This totals 12-18GW (24-26GWh), leaving an unmet need for 7.4-13.4GW (102-104GWh) which Storelectric can supply more cheaply than gas-fired peaking plants.

Appendix B: Electricity Storage Solutions

Most so-called "grid-scale" storage is at a scale of 10s of MW, and 10s of MWh. While extremely useful for local issues (e.g. capacity enhancement, islanding at small scale, maximising output from small to medium scale renewable generation) and for short timescale issues (e.g. frequency and voltage response), it completely misses the big problem. It may be grid connected, but it's not grid scale. Doubling either size or capacity increases capital costs of an installation by typically 85% as the number of cells needs to be doubled.

In contrast, Storelectric offers truly grid-scale electricity storage, with each 500MW, multi-hour plant costing only £350m (£460m for the first-off), and a levelised cost less than that of a gas-fired peaking plant. It can be up to 100% renewable. This complements all the other storage technologies on offer, and works equally with renewables and fossil fuel generated power, thereby supporting the transition also. Doubling its size or capacity (assuming that the capacity increase is matched with thermal storage – the higher-cost but lower-emissions option) typically increases its capex by about one-third.

What is needed is an entire raft of electricity storage technologies, which we split:

Scale	Power	Capacity	Technologies Best Suited
Domestic	<100 kW	<250 kWh	Batteries, supercapacitors, flywheels
Local	<1 MW	<5 MWh	Batteries, supercapacitors, flywheels, cryogenic
Area	<10 MW	<50 MWh	Cryogenic, heat, large batteries, flow batteries
Regional	<100 MW	<500 MWh	CAES, pumped hydro, poss. flow batteries, heat
Grid	>100 MW	>500 MWh	CAES, pumped hydro, (future) hydrogen

The market can also be segmented by response time.

There is room in the market for all the technologies that deliver one or more services cost-effectively. For the next decade or two, our main competition is not each other – it's ignorance and bad policy.

Distributed Schemes

Many propose that distributed generation and storage will solve the problem. It is true that they will go a long way towards solving the problem, but every single distributed storage scheme of attainable (not even cost-effective) cost relies on the grid to provide back-up power when batteries are exhausted and generation is lower than demand. So where does the grid get its power from, to provide this back-up?

Demand Side Response (DSR)

Currently DSR is defined to include both consumer-owned generation which accounts for 80% of capacity, and demand displacement (temporary reduction in

demand when required, to be made up later, e.g. switching off freezers for 15 minutes, to be re-cooled later) which accounts for 20% of capacity. This is unfortunate: consumer owned generation (mostly diesel generators) is the costliest and most polluting form of generation, whereas demand displacement uses very little extra energy overall and is the most cost-effective means of absorbing peaks and surges in demand. The former needs to be abandoned, while the latter deserves its place in the energy mix.

Batteries (Non-Flow)

The most fashionable technology is lithium ion batteries, though it has competitors in other lithium- and sodium-based chemistries, and in lead-acid; each has its advantages and disadvantages. A major disadvantage of lithium is that there isn't enough of it (or of cobalt and other esoteric metals) in the earth's crust to support the grids of this planet, so it's much better used in applications where its weight, bulk and energy density are at a premium: portable equipment and transportation.

Supercapacitors, Flywheels, Flow Batteries, Pumped Hydro

Supercapacitors and flywheels are best for ultra-short duration. Cryogenic is otherwise known as Liquid Air Energy Storage, fairly expensive and complex but without geographical limitations. Flow batteries' dirty secret is that they tend to involve swimming pools full of concentrated acid. All batteries have environmental issues related to mining, refining, processing and disposal. Pumped hydro is ~98% of installed capacity, ~75% efficient (higher numbers for some plants rely on in-flowing water), flood one or two valleys, are considerably dearer than CAES and have few potential locations that tend to be very remote from both supply and demand.

Compressed Air Energy Storage (CAES)

CAES has some geographical limitations but potential locations are widespread world-wide. It comes in 2 versions: diabatic (traditional) and adiabatic (such as Storelectric). Compressing air to a typical 70 bar (~30x car tyre pressure) heats it by ~605oC, but the air must be stored at close to ambient because it's stored underground in salt caverns (nothing else is big or cheap enough; though other geologies will be available in future) and the geology requires it. Expanding it to regenerate the electricity cools it to below -150oC. Traditional CAES puts the heat back in by burning gas: inefficient (42–50% round trip) and polluting (50–70% of the emissions of an equivalent sized CCGT). Adiabatic CAES extracts the heat of compression, stores it separately and puts it back in during expansion, increasing efficiency to 60–70% and eliminating emissions; hybrid technologies are possible.

Note that batteries tend to quote their efficiencies as "gross" rather than round trip. The difference is the cooling, power conversion etc. Thys grid connected batteries' actual round trip (i.e. grid-to-grid) efficiency is 42–68% depending on scale, on day 1; by year 5–8 their heat losses have tripled and so efficiency drops. CAES efficiencies are quoted as grid-to-grid.

But how much?

The Grid identifies up to almost 6GW of DSR potential in the economy (fig. 3.5.1) by 2025, shrinking to 5GW by 2038, in the most optimistic scenario, a significant proportion of which (two-thirds of current 1.8GW capacity, in the FES 2016 report) is highly polluting and therefore (in the medium term) unwanted diesel generation and should therefore be disregarded. A proportion of that will never be realised, as many customers will never want to hand over control of their washing machines or other equipment to electricity companies. Another reducing factor is that if needed two or three times during a peak (e.g. the classical advertisement breaks during a popular programme), different DSR assets need to be used for each. Note that peak demand will already have been reduced by 1.6GW by widespread adoption of time-of-use tariffs (figure 3.5.4), reducing scope for DSR.

The prevalent market view is that DSR is valid for up to 3-5% of peak demand. Beyond that, we would be paying £billions to degrade our first-world grid to a third-world grid. (In a first-world grid, when I switch on a switch, the electricity is there; in a third world grid, it will think about it.) But 5% of peak demand is still 3GW, an immense 75 times current capacity – there's room in the market for all these suppliers, too.

Appendix C: Interconnectors

In FES 2018, "electricity imported through interconnectors is counted as zero carbon when calculating GB emissions." (p33) There is no comparable statement either supporting or negating this in FES 2019. This is perverse, and is not balanced by an accounting for the emissions of exports. Moreover, as nearly all EU countries are planning to be importing peak electricity during periods of low intermittent generation, this fantastic assumption of zero emissions imports is replicated across the continent – at just the time when emissions are greatest as peaking plants are turned on to support peak demand, again throughout the continent.

The planning models used by FES 2019 compare the prices of electricity and services through interconnectors with domestic ones. However they ignore the subsidies of free grid access (i.e. single charging – for access charges within the price of the electricity bought, as opposed to triple charging for storage, proposed to reduce to double charging), cheaper grid access costs in Europe, cheaper carbon price in Europe, and no charging of the differential as it is imported. Remove these implicit subsidies and the economic benefit of interconnectors greatly diminishes. Indeed, FES 2018 explicitly recognised this with regard to carbon prices (but not grid access charges) on p109 – again, no mention in FES 2019.

In their Electricity Capacity Assessment Report 2013[31], Ofgem completely discounted reliance on any power from interconnectors – though they have modified their views since then. Not only do all our neighbouring countries suffer comparable shortfalls in generation capacity with Britain's, but also their demand patterns are similar. The corollary of these two factors is that if we are allowed to draw power through interconnectors when our neighbours also want it, we are likely to be paying high prices in order to do so. Nevertheless, at times when these neighbours' systems are not stressed, interconnectors provide ample electricity at reasonable marginal prices, and serve an excellent purpose in lowering Britain's overall energy prices.

As if to emphasise this point, "In February 2015 National Grid Nemo Link Limited and Elia, the Belgian Transmission System Operator, signed sign a joint venture agreement to move ahead with the Nemo Link"[32] even though Belgium was the first country in Western Europe to be planning openly for rolling black-outs[33] to make up for potential generation shortfalls, and Belgium's interconnection capacity is 3.5GW, or 25% of their 14GW peak demand[34], as compared with Britain's current 4.15GW, or under 7% of peak demand.

---

31 https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013 p41-44

32 www.nationalgrid.com

33 http://datafable.com/rolling-blackout-belgium/viz/

34 http://energy.sia-partners.com

Yet National Grid is accelerating its reliance on interconnectors, from the current 4.15GW to 23.3GW by 2040 (Two Degrees scenario).The fact that we saw strong flows into the UK during peaks in winter 2014 is due primarily (in my opinion) to the exceptionally warm winter noted in the Winter Outlook Report 2014, rather than to their reliability when demand is high: as stated, "French and Belgian supply is expected to be relatively tight until 2020 due to closure of old fossil fuel plant and some nuclear reactors. As conditions vary and put more stress on the market in coming years, this could lead to more volatile prices and therefore interconnector flows between GB and the continent. This is particularly the case over the peak demand of the day."

Because of their function in lowering overall energy prices and making

"However, GB is not the only European country expecting de-rated margins to fall in the next six winters. … Our analysis also suggests that, at the moment, there are no evident complementarities between GB and its interconnected markets as we have very similar patterns of demand and supply availability."
- Ofgem Electricity Capacity Assessment Report 2013

Note: the BritNed interconnector costs £0.5bn for 1GW of uncertain supply; longer interconnectors are dearer. Storelectric will in future provide 1GW of certain supply for £0.7bn.

solution, but an important part of the solution.

Interconnectors and Brexit

Britain has voted to leave the Single Market and the jurisdiction of the European Court of Justice. These were the only two entities that guarantee that, under system duress, neighbouring countries fulfil contracts to deliver energy to the UK. Following expiry of the transitional period, unless there are some very unexpected developments in treaty negotiation, it will become a political imperative for

neighbouring countries to cut off the UK during times of system stress. Who can imagine (for example) TeneT telling the Dutch government that black-outs in Amsterdam were due to exporting the electricity that they needed there to the UK to earn a few million Euros? This would apply to all our neighbouring countries.

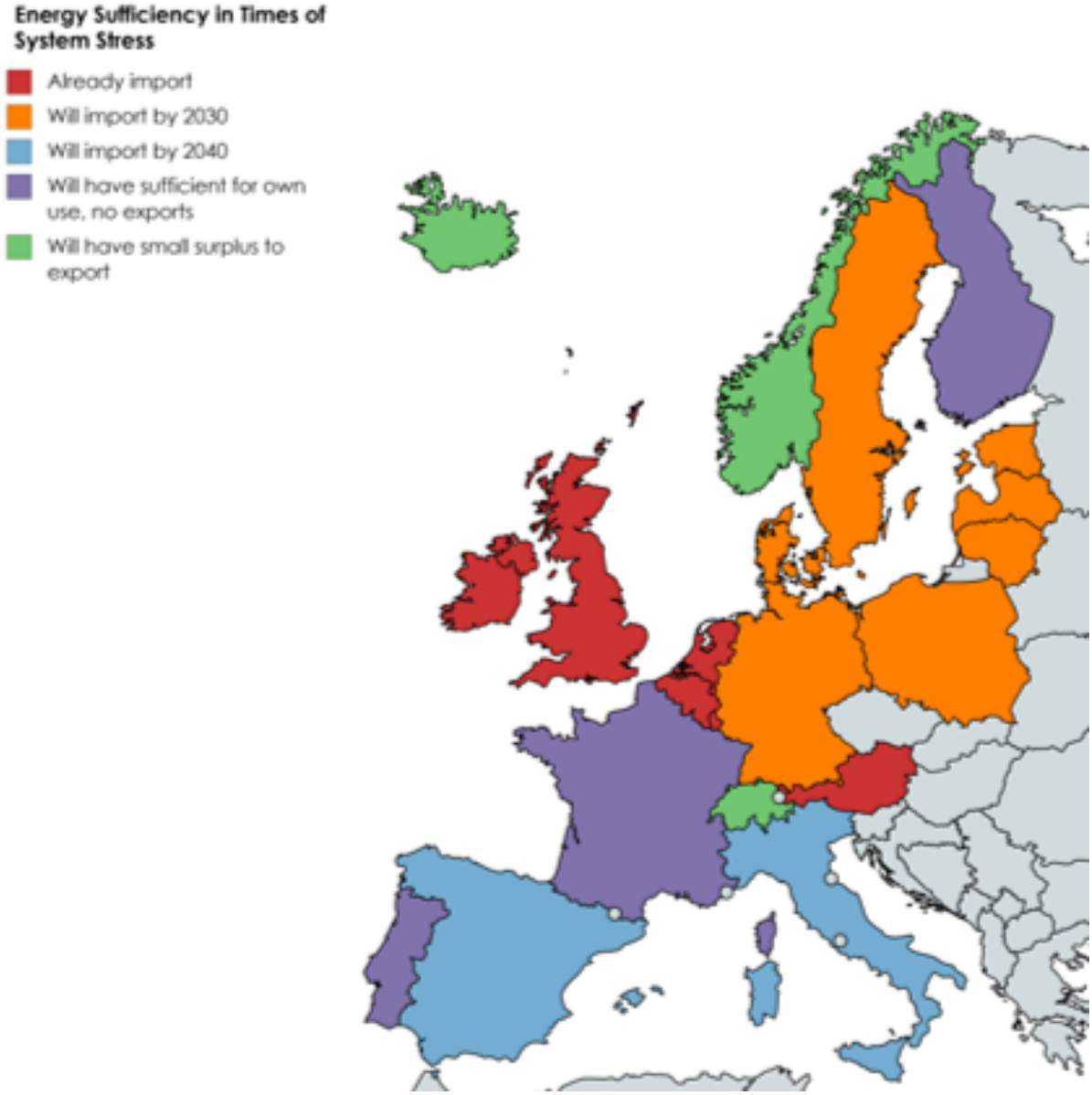
It is worth noting that this entails importing 1/6 – 1/4 (depending on scenario) of the country's peak demand by 2025, making up (by the same year) over one quarter of our total energy demand, through interconnectors from neighbouring countries. Not only does this indicate a massive domestic energy generation shortfall, but it also risks making Brexit negotiations hostage to our needs: we will be compelled to come to whatever agreement is necessary in order to be able to import these volumes, potentially weakening our opportunity to negotiate countervailing export market access such as for financial and other services.

It is also worth noting that interconnectors are part funded by the European Commission's Connecting Europe Facility (CEF), and rely on this to a greater or lesser extent for their financial viability. The innovation budget of the EU is funded by 6 countries more than the membership, including Norway, Switzerland and Azerbaijan, so it is possible for the UK to continue to use it – provided we pay into the budget, which may cause political issues in the UK. It is also possible for the UK to provide its own equivalent to CEF (and Horizon 2020 etc.) money, but that would require duplicating administration and an administrative layer to co-ordinate with the EU at both governmental and project levels.

From Where Will We Import?

We have studied the energy transition plans of 6 countries in detail (UK, DE, FR, IT, ES, NL - who account for 75% of EU GDP - please forgive the number of abbreviations!) and are aware in general terms of the plans of most of our other neighbouring countries. As can be seen from the map, during "times of system stress" (i.e. high demand and/or low renewable generation) the UK, NL, BE, EI and AT already rely on electricity imports through interconnectors. By 2030 these will be joined by DE, PL, SE and the Baltic states. By 2040 Spain and Italy will join them. France and Finland will have enough for their own needs due to nuclear, and Portugal due to hydro - but no surplus to export. Only Norway, Switzerland and Iceland will have electricity to export - and a 1GW interconnector to Iceland is expected to cost more than £5bn.

Given that these "times of system stress" are largely concurrent (e.g. after sunset on a windless winter evening), this means that there will not be enough spare electricity for all the countries that rely on the imports, yielding rolling black-outs and brown-outs (euphemism: enforced DSR) in all of them. And in terms of prioritising who gets the trickle of exportable electricity, a no-deal Brexit means that for the first time ever, our neighbours can tell us "I don't care how much you're offering to pay - our consumers are more important to us than are yours".



Therefore the only way for each of these importing countries to keep the lights on, and especially for the UK to do so, is large amounts of large-scale long-duration storage.

Interconnectors and Emissions

Finally, the assumption that "electricity imported through interconnectors is counted as zero carbon when calculating GB emissions" (p33, FES 2018) must be challenged. Imports carry a proportion of emissions in their generation mix, unless specifically contracted from zero carbon sources. At times of low renewable generation, when the UK will be importing the highest proportion of our electricity, neighbouring countries are often undergoing similar weather patterns to ours, or continuations of the same pattern; therefore they too would be experiencing low intermittent generation. Consequently they would (like the UK) be turning on peaking

plants to satisfy demand, and carbon intensity increases. For this reason it is safer to assume that electricity imported through interconnectors has an average carbon / emissions content ***higher than*** the average carbon / emissions content of the grid from which it is being imported. Therefore this use of interconnectors merely fudges the emissions figures and guarantees that the country will fail to meet its decarbonisation commitments.

Appendix D: A 21st Century Electricity System

Introduction

The current regulatory and contractual framework is designed around a 20th century industry (baseload coal and nuclear, dispatchable gas, all other bits are add-ons). The cost of electricity is diverging increasingly from its price: already around half of commercial customers' bills consists of levies and system charges, with only around half (this being a decreasing portion) being for the electricity consumed. In a well designed system, the price of electricity should account for between 75% and 80% of its cost. Thus the headline prices may need to increase, without necessarily affecting the cost of electricity to customers.

A 21st century regulatory and contractual framework must be designed around renewables and storage (with or without nuclear) supported by distributed generation and storage, interconnectors and Demand Side Response. Features of a 21st century system would include the following.

Regulatory Framework

Until RIIO was developed, National Grid was incentivised on cheapest electricity over a 2-year period. That provided cheap headline prices but without any concern for the future of the system. When RIIO was brought in, an 8-year horizon with attendant incentives were brought in, which was a big, but insufficient, improvement.

To ensure system reliability and cost-effectiveness over 15 years requires 15-year timescales. Ditto any other period. This is because the cheapest way to deliver a 2-year contract is to patch up a clapped-out and fully amortised plant. For the next 2-year period the same is done again, and again until the plant dies of old age. But with each repeat, the plant is older, less reliable and more costly to patch up. So over 15 years the total cost of electricity would be higher than under a 15-year contract because the latter would have been delivered by building a new plant. The short term timescales alone therefore ensure that investments with long lives and long term pay-backs are penalised financially, and also are added to the commercial risks that are put against the SO's balance sheet.

Therefore, in addition to the 2- and 8-year regulatory and rewards regimes, there also need to be 15- and 30-year timescales. The shorter timescales would have greater emphasis on consumer prices and lesser emphasis on system integrity, gradually reversing as timescales extend. This will ensure that not only is the grid cost-effective now, but also that it will be both cost-effective and systematically sound in 30 years' time, with all long term investment undertaken as needed.

Another RIIO problem is that every 8 years all "base cases" are re-set. Thus at the beginning of a RIIO period, investments can be made with an 8-year amortisation life; half way through, this drops to 4 years; and towards the end of the period, significant investment is almost impossible. This should be changed to a "regulatory amortisation" of each investment over the viable life of the asset, or over a

reasonable lifetime determined by the regulator. Accountants manage such amortisations for large businesses very happily even though every plant is being amortised from a different date for a different period (or one of a set of permitted periods): therefore the regulator should be able to manage "regulatory amortisation" similarly.

Contract Structure

No major investment is possible without long term contracts or other form of revenue assurance. The only capital investments in major infrastructure have come on the back of special arrangements that offer such assurances, e.g. CfDs, ROCs, OFTOs, CATOs.

Without long term contracts, a 2-year contract will appear to be the cheapest way of procuring electricity over a 2-year period. But it will be bid on marginal cost and delivered by patching up a clapped-out and fully amortised plant. On the next 2-year cycle the same will happen again, though the plant will be older, more worn, more expensive to patch up and more prone to break-downs. Over a 20-year period the country will have paid more overall for its electricity than if 20-year contracts had been let, which would have been delivered by new plant – and in the meantime no new plant is built, the old plant dies of old age and the system's capabilities plummet. Meanwhile, in order to incentivise investment there need to be special mechanisms (subsidies by another name) put in place which mean that the total cost of delivering electricity (including subsidies) is greater even in the short term than would be the case under longer term contracts.

A truly sustainable grid will engage most or all services under contracts of lengths that both encourage investment and minimise cost. Such a structure could include:

- 1/3 of energy under 15-20 year contracts, with delivery to start following grid connection, these contracts only being available for new build;
- 1/3 of energy under 5-8 year contracts, with a split between new and existing plant to be decided according to the reviews of the system from time to time;
- 1/3 of energy under contracts of up to two years, for all plant.

There is indeed some measure of uncertainty as to future demand. This can be accommodated by (a) letting such contracts in rolling annual or biennial auctions and (b) flexing the exact amount of mid- and short-duration contracts.

The entire subsidy regime and scheme of access charges need to be re-thought:

- Incentivise cleanness of technology, for example with longer contracts going to cleaner technology. An example would be full-length (as above) contracts for zero emissions generation; half-length contracts for CCGTs, with durations on a sliding scale directly proportionate to emissions between the two, that scale continuing to diminish contract length for technologies with worse emissions than CCGTs.
    - Include ancillary emissions in the calculation of the emissions of a given technology: mining, harvesting, refining or otherwise processing,

manufacturing, transporting, recycling, disposing of equipment (both main and ancillary, including considerations of operational life), components, materials and fuel.

- ◊ Ensure that imported electricity is deemed to have the emissions performance of the electricity that is delivered to the interconnector. Where that is difficult to determine, default to the average emissions performance of the source country and, if appropriate (e.g. Belgium, Netherlands) considering a proportion of the electricity to come from their neighbouring countries, at their average emissions performance. This would apply to carbon pricing and any other incentivisation scheme including contract duration.

- ♦ Incentivise dispatchability with a price premium that reflects the balancing costs avoided (or a large proportion of them, so both sides benefit).

Ensure that all capabilities can be monetised, e.g.

- ♦ Permitting real inertia to compete in the EFR market with a premium based on the fact that it is instant and requires no grid intervention, whereas EFR has milliseconds' delay and requires grid intervention. Ditto reactive power.
- ♦ There is currently no contract scheme for long term storage. If such a provision were made, then negotiated bilaterally for e.g. the first 1TWh stored (with a minimum installation size of 100GWh) prior to creating an auction for it, then this would enable the scheme to be available when the technology is developed to use it - and would thereby incentivise the development of that technology. It would also enable the contracts to be structured around the actual costs and benefits of the technology, rather than around a theoretical exercise. Similar mechanisms could be used for other services as their need is identified.
- ♦ Ensure that the various services are co-ordinated so that any plant that can deliver multiple services is able to contract to do so.

Eliminate the Capacity Market, which is a subsidy for fossil fuelled generation.

Contract Simplicity

There are currently 15 different contracts under which balancing and ancillary services are purchased, and this number is increasing steadily. Germany, for all its faults, has 3. Large scale storage needs a stack of 8-10 contracts in order to earn full returns on investment; small scale storage stacks 6-8, and demand side response almost as many. Even generation, which used to have one contract, now has many. All except one (Capacity Market or EFR, depending on technology) of these has a duration of between 6 months and 2 years. Assuming an average duration of 1.5 years, this means that, at best, large scale storage has to fund an overhead to bid for 8-10 contracts every 1.5 years. And every contract type is different, with different terms, conditions and specifications, all of which have to be understood and juggled not only by the bidding bureaucracy but also by plant operators who have to fulfil all those contracts, and by spot traders who have to know exactly what will be surplus

at what time. And it entails similar complexity and overhead in the System Operators Contracts team and control centre.

However each bid carries the risk of losing the bid. This will entail a costly hiatus in contractual cover while another (usually less remunerative) service is bid for. This can double the already huge administrative overhead of bidding. It also means that there is a financial risk, which adds to the risk premium on the investment and therefore to the capital cost of the plant. These risk premia also lead to high levels of profits when things do not go wrong, leading in turn to screaming tabloid headlines and high political risk.

The system needs simplifying. A plant should be able to tender all its services as an individual plant in one tender – or two, if demand side (DSR, demand turn-up) is included. Individual services should only be tendered if there is a specific resultant shortfall in the capabilities that have been engaged – which there shouldn't be, as there is some flexibility in capabilities, such as primary frequency response assets continuing for the duration of secondary response and even fast reserve.

The Most Cost-Effective Contracting Sequence

Letting contracts for such services individually causes major issues and maximises the cost and complexity of letting, administering and delivering the contracts, for both grids and service providers. The biggest problem that it causes is to flexible plants that deliver many services, such as inertial plant which cannot deliver electricity without inertia and other related services.

- What happens if a plant is unable to deliver services A, B and C separately and wins contracts for A and B but not C? Do they have to "give away" C without remuneration, putting them at a commercial and financial disadvantage? Are they penalised for excessive delivery of C?
- What happens if, in delivering A, B and C they are vastly cheaper than the competition in delivering D? The total of A-D is cheaper than any other means of procuring them, but A-C on their own are more expensive. Should the system pay extra to procure them separately or should it aggregate A-D to provide all the services more cost-effectively?

The most cost-effective contracting sequence would be:

1. Let the longest-duration and hardest-to-place contracts first;
2. See what else the winning plants can deliver cost-effectively, and award those contracts to such plants;
3. Only auction off the next-hardest-to-place contracts that remain outstanding after step 2, and repeat.

This will ensure that each plant that wins contracts can amortise its costs over the widest range of contract types for which it is cost-effective. This in turn enables those contract prices to come down due to contractual coverage and revenue security, and also because fewer plants are needed in the system to deliver the requisite energy and services.

For example, of the reverse were to be done, then:

1. Large numbers of peaking plants and batteries would be built to cream of the biggest revenue streams;
2. Harder-to-place contracts would be more expensive as these parts of the revenue streams are no longer available to them;
3. Plants for these harder-to-place (including longer-duration services) contracts will not be built without much higher prices as they cannot be justified on the back of the easier-to-place contracts, and won't already have the other contracts "in the bag" to be able to spread the amortisation of their costs.

Incentivising Clean Energy

All the above is regardless of energy technology. However clean energy can be incentivised, without subsidy or price premium, by superimposing cleanliness-related contract length.

To do so, the base contract lengths would need to be extended so that imperfectly clean technologies can also have sufficient contract duration to enable investment. Thus for a 100% clean / renewable technology, the longer two contract lengths would be 20 years and 10 years. For a diesel or coal (whichever is more polluting for the service being contracted) fired power station, contract lengths would be half of that for the clean technology, i.e. 10 years and 5 years. Maximum contract durations for technologies with intermediate levels of cleanliness between these two end-points would be linearly proportionate between those durations. So a new build with half the emissions of a coal fired power station could have a contract of up to 15 years, and a refurbishment up to 7.5 years. It may be politic to let contracts in steps of whole numbers of years, in which case the refurbishment would have a contract length of either 7 or 8 years depending on whether the decision is to round up, down or to the nearest integer.

The emissions performance should be calculated as a whole-system (or, in the case of storage, round-trip including all energy inputs and useful energy outputs) efficiency *for the particular duty cycle being tendered*, rather than a standard figure being applied for all duty cycles. This is because, for example, a 60% efficient gas-fired power station would be a very high performance for frequency response, but not as good for baseload.

For stand-alone storage, the calculation would take into account two factors: cleanliness and efficiency. In order to be considered on a level playing field with generation, both "inefficiency" and "dirtiness" should be factored down by 50% and then added to obtain the "undesirability factor" which is then subtracted from 100%. Thus a 60% efficient (i.e. 40% inefficient) storage system that creates 20% of the emissions of a coal/diesel fired plant would be factored down by 20% for inefficiency + 10% for dirtiness, total 30% undesirability, for a contract length equivalent to a 70% clean plant, resulting in maximum contract lengths of 17 years for new and 8.5 years for refurbishment. The justification for this factoring down is that storage provides a

balancing service that maximises the efficiency of the whole system, and does so more effectively as the proportion of renewable energy in the system grows. Thus efficiency is incentivised, as well as cleanliness.

Incentivising Dispatchability

Dispatchability could be incentivised similarly to cleanliness of batteries, in that a non-dispatchability factor could be added to the dirtiness factor. Thus there could be (say) a 10% reduction for long term predictable variability (e.g. tidal lagoons and tidal flow turbines, 4 generation slots per day), 20% for only short term predictable variability (e.g. wind and solar generation). There could be an intermediate step for medium term variability such as wave power at 15% factor, if deemed appropriate.

Where dispatchability is increased by co-location, near-location or contracting with storage, then generation and storage patterns and efficiencies should be modelled to identify the forecast true output and dispatchability figures, and the dispatchability factor scaled accordingly. Where such storage is of limited capacity (e.g. less than the nameplate capacity of the generation) or limited duration (e.g. fewer than 5 hours at nameplate capacity of the storage), then the storage only partially creates dispatchability. In such cases, the storage would not be evaluated separately as stand-alone storage. One could conceive of a storage facility contracting a proportion of its capacity to a dispatchable generator and the remainder as stand-alone, in which case a compound figure could be calculated.

Non-Financially Incentivising Innovation and New Technologies

New technologies from innovative start-ups are actively prevented from developing their plant as contracts are only considered following grant of planning permission, which itself follows the study and reservation of grid connections. Therefore for a large plant, millions of pounds (which an innovative start-up does not have) are needed before the contractual cover is offered which would provide the revenue underpinning required for investors to put in the money needed for the grid connection and planning applications. It's a Catch 22. A second Catch 22 is that many investors won't invest without a reasonable expectation of long term contractual underpinning of revenues, which cannot be granted unless the technology is developed.

A simple way to break through these barriers and to incentivise innovation and new technologies without money (though it would best be done in conjunction with the other incentives, below) would be by early official memoranda of understanding (MOU) and letters of intent, and progress monitored to ensure that the SO understands its impact, likelihood and timing as the project develops. With these, our potential financial backers would almost certainly open their purse strings.

- For a proposal to build a first-of-a-kind plant, a letter of intent from the System Operator to state that provided certain conditions are met (those being specific to the plant being developed, e.g. FEED Study complete and supporting the previously claimed minimum performance, planning permission

granted, grid connection application granted), then it is the intention of the SO to grant a 15-year contract at the rates applicable at the time.

- For such a proposal, a memorandum of understanding from the Network Operator to say that prima facie a grid connection (specified) would be available within a specified cost and timescale, unless other applications were received between the date of the MOU and that of the formal grid connection application. This helps to shorten timescales and liberate funds because currently grid connections can only be applied for following grant of planning permission which, for a transmission grid connected scheme, will cost ~£2m and take ~2-3 years. The prospect of an affordable grid connection will help liberate the private funding for the design and planning process.
  - Permitting grid connection applications to be applied for prior to grant of planning would considerably reduce the up-front risks and timescales of any project.
- For an earlier stage innovation, if it would create a technology useful to the SO, then a less binding memorandum of understanding from the SO that if the technology achieves specified milestones (demonstration on paper of technical and commercial viability), then the above letters of intent will be forthcoming. This will provide the support to the project that will show to early stage funders that the technology has a commercial future if it can be developed as claimed.

Additionally, permit system operators to invest in new generation / storage technologies and to own the consequent plant for a limited period, e.g. 5 or 10 years (possibly depending on size of plant / investment) between commissioning and sale. The proportion of the plant they can own could depend on the proportion of innovation in the plant. Any IP should have to be licensed to all who wish, but with royalty revenues accruing to the system operator as per normal commercial R&D investment.

Financially Incentivising Innovation and New Technologies

To encourage new technologies, replace ROCs and CfDs with a price supplement (pence per kW) for early stage installations of new technologies, e.g. add to all revenues 50p/kW for a first-of-a-kind plant (that is, full scale rather than experimental), diminishing linearly to zero for the 6th of a kind. If the differences from other plant types are smaller, then this premium can be reduced accordingly, but should still remain in order to incentivise innovation.

- By incentivising first-of-a-kind plant, it encourages these to be built in Britain. This incentive could be made contingent on (or proportional to) the development, engineering and manufacturing of the technology being located in Britain - which would incentivise innovative foreign companies to move in.

Create a branch of the NIA / NIC investment fund to be administered centrally by Ofgem to incentivise R&D which would benefit the electricity system as a whole but not the grid operators individually due to regulatory or commercial constraints. It should be administered to favour UK-based R&D, manufacturing etc., maybe with

the proportion of costs covered being proportionate to the UK-based work (excluding installation - which is a gateway factor) as a percentage of the whole.

Other incentives for the development and introduction of new technologies should be considered, not only at the innovation stage but at the pilot and first grid connected plant stages where there is a dismal shortfall in both money and non-financial support to flex the contractual and regulatory regimes (even if only on a one-off basis to test the benefits to the grid) to enable and encourage them.

Conditional contracts would greatly assist fund raising. They could be phrased along the lines of: “if this plant can be built and deliver these services at these prices, then it is the intention of the System Operator to enter into a contract at the higher of these prices and the market prices applying at the time.”

Time to Start of Delivery

Building new plants in new locations requires grid connection. Such grid connection can entail significant grid reinforcement. However the reinforcement can take 5-10 years to plan and implement, which exceeds the longest possible time allowable under the RIIO framework. Contracts for new build need to permit suitable delays to start of delivery of the multi-year contracts, in order to enable new construction.

Some discretion may be given to the System Operator as to whether or not a plant is wanted to be connected to that part of the grid. And the issue is moot for plants that use existing grid connections provided those existing connections retain their access capacity.

Grid Access

Ensure that all generation, whether UK or overseas, pays the same grid access and usage charges.

Treat storage as a grid service, not as generation or consumption – or, at worst, allow storage to pay for charges after netting generation against consumption, which would incentivise efficiency.

Instigate a methodology for ensuring that grid reinforcement costs also capture the benefits of reinforcement deferral arising from some investments (e.g. generation on a particular side of a bottleneck) and sharing those benefits with the investor, e.g. 2/3 to the investor and 1/3 to the grid operator. Some of these benefits may be reflected by one-off payments, others by annual payments: in order to maximise the incentive to build such plant, and to reflect the timing of the benefits to the grid operator, they should be paid in advance; any adjustments can be made the following year to reflect actual usage and/or performance.

Grid Definition of Storage

Create a grid definition of storage modelled on that for interconnectors. This will permit and regulate:

- Contracting for services which are delivered off peak from storage that is replenished when market price differentials are not as high as between delivering at peak and replenishing at trough prices;
- Contracting for storage services per se;
- Ownership and investment into storage systems – maybe for only a fixed period, say 5 or 10 years from start of operation to deadline to sell the plant.

It will also eliminate:

- Over-charging for grid connections and reinforcement, indeed creating a mechanism for payments to developers to reflect a large part (2/3?) of the savings from grid upgrade deferral;
- Double charging for grid access for both charging and discharging;
- Having to pay market premia (profits, mark-ups etc.) for both buying and selling electricity.

Whole-Operation Contracting

Consideration should be given to whether System Operators (SOs) should be permitted to contract with a given storage provider / installation for “all services”. This is because the number of services offered by storage far exceeds that offered by generation, and such a contract would maximise the ability of the SO to use each service from storage in the most cost-effective manner. The main issues to be considered are whether and to what extent this would make the SO into a storage system operator, and whether or not such a change would be desirable.

CAES (Compressed Air Energy Storage), for example, can offer:

1. Various embedded benefits;
2. Firm Frequency Response (Secondary, and possibly some primary);
3. Fast Reserve;
4. Short Term Operating Reserve (STOR)
5. Supplementary Balancing Reserve
6. Reactive Power MVAr
7. Demand TurnUp
8. Wholesale Peak
9. Wholesale Off-Peak
10. Balancing Mechanism
11. Capacity Mechanism
12. Black Start

While batteries cannot offer the long generation durations required by STOR and the Balancing Mechanism, they can offer Enhanced Frequency Response and Firm Frequency Response (primary).

There are various models and precedents for such contracts, including CATOs and OFTOs.

Another benefit is that SOs require such services during off-peak times as well as peak times. If required at off-peak times, then the storage would have to re-charge at higher prices while generating its revenues at lower prices, making it unprofitable. Such whole-operation contracts would enable the provision of these services at off-peak times to be profitable for the storage provider.

Appendix F: Ofgem and BEIS Recognition

From the Smart, Flexible Electricity System consultation paper published jointly by BEIS and Ofgem, November 2016:

- "And, as well as meeting new challenges, we must seize the opportunities enabled by a smart system – including ... the use of advanced energy storage technology." Covering letter from Greg Clark, Minister.
- "It builds on the position paper on Flexibility we published last year. In that, we stated our priorities were the roles of storage and ..." Ofgem Foreword.
- "In line with the plans both Government and Ofgem set out last year, we have considered a range of options to deliver a smart energy system, including: removing barriers to storage and DSR; ..." Towards a smart, flexible energy system para.20.
- "We have found that storage faces a number of barriers", as an introduction to a request for ideas to remove those barriers. Towards a smart, flexible energy system para.22.
- "Government has identified a number of potential priority areas over the next 5 years: ... storage costs. ..." Towards a smart, flexible energy system para.50.
- Towards a smart, flexible energy system, Table 1:
    - "In the final plan we will set out implementation tasks and timelines for: Any further measures to make it easier for storage to connect to the network - A decision on regulatory definition for storage and whether a new licence is required".
    - "Our aim: a level playing field for DSR and storage competing with other forms of flexibility and more traditional solutions."
- In the National Infrastructure Commission's report on Smart Power recommendation 2a) was that "DECC and Ofgem should review the regulatory and legal status of storage to remove outdated barriers and to enable storage to compete fairly with generation across the various interlinked electricity markets. The reforms should be proposed by Spring 2017 and implemented as soon as possible thereafter." https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf - note 17 to Introduction, Table 2.
- 2. Removing policy and regulatory barriers, 2.1 Enabling storage
    - "1. There is increasing interest in energy storage as a potential source of flexibility for our energy system"
    - "2. Falling costs are one element of bringing forward large scale storage projects – the market and its structures must also recognise and reward storage for the value it brings to the energy system."
    - "3. We are seeking views on solutions; both for individual barriers and whether some solutions could address multiple barriers e.g. regulatory clarity."

So BEIS and Ofgem are keenly aware of the need for storage at all scales from domestic to grid scale, and are actively seeking ways of enabling it to happen, and to remunerate it fully. Unlike other storage solutions, we can demonstrate strong profitability and IRRs in today's market with today's regulations: all these changes being contemplated merely add to our potential.

From BEIS (UK gov't) ***Building Our Industrial Strategy*** *consultation:*

This paper "also consults on the technologies which the new Industrial Strategy Challenge Fund could support, including: smart and clean energy technologies (such as storage …)"

"The government has also asked Sir Mark Walport, the Government's Chief Scientific Adviser, to consider the case for a new research institution as a focal point for work on battery technology, energy storage and grid technology [by] early 2017 ."

"To ensure that new energy technologies are developed here – and the UK benefits from global investment in this area – we have doubled support for energy innovation, and are

Recognition of the Need and Government Wrong Actions

Some people have recognised the scale of the problem:

> "Electricity storage has the potential to provide savings of more than £10 billion per year by 2050—that is £400 per household" – Lord Grantchester in parliament, 18/7/13
>
> "..... we have designed the enduring capacity market to ensure that demand reduction and storage can participate effectively by running capacity auctions both four years ahead and one year ahead of when capacity is expected to be required. ....." – Baroness Verma, DECC minister, in parliament 18/7/13
>
> "Electricity demand peaks at around 60GW, whilst we have a grid capacity of around 80GW – but storage capacity of around just 3GW. Greater capability to store electricity is crucial for these power sources to be viable. It promises savings on UK energy spend of up to £10bn a year by 2050 as extra capacity for peak load is less necessary." – Chancellor of the Exchequer George Osborne, 9/11/12
>
> "Reports from Imperial College show that the cumulative value to the UK of flexibility [in power generation] is £60bn by 2030." – Electricity Storage Network in 2014 (not on website now, www.electricitystorage.co.uk)

So where has the government's and other public / semi-public bodies' financial support gone?

- £billions to subsidise fossil fuelled power stations, through the Capacity Market;
- £1bn to subsidise fossil fuelled power stations, through CCS demonstrators (while these 2 projects were cancelled after considerable costs, CCS power generation remains a government priority and continues to attract funding);
- £10s of millions to subsidise area scale projects such as Quarry Battery, Highview and Isentropic;
- £10s of millions to subsidise batteries, at similar or smaller scale;

- Negligible support to regional or grid-scale storage.

Likewise, all government incentives (Capacity Market, CfDs, ROCs etc.) are geared towards production regardless of the time at which it is needed, and none towards either storage or making electricity available at the time needed. This could easily change: for example, the government could increase substantially the value of CfDs and ROCs to renewable generation on condition that it generate baseload power, or dispatchable power, thereby incentivising renewable generation to contract with storage and to support its development.

Since June 2015 the government has announced large restrictions to CfDs and the end of ROCs. This greatly reduces the investability of new technology projects: CfDs provided the only guaranteed sales, albeit with prices fluctuating with the market, within limits. The National Grid is not permitted to offer contracts for longer than 2-3 years, which does not create financial-market “bankability” for new technology investment. Moreover, all of these (as well as CfDs, from 2014) are let by auction which means that even such short term contracts cannot be relied upon. The government needs to permit long term (10-20 year) contracts, some of which are awarded without auction for new technologies in the widest sense.

Appendix G: Battery Efficiency

CAES has various quoted levels of efficiency. Storelectric's is much better:

- Huntorf (traditional OCGT-based CAES): 42%
- McIntosh (traditional CCGT-based CAES): 54%
- Dresser Rand's SmartCAES (an evolution of McIntosh): up to 60%
- Storelectric CCGT CAES: 60%
- Storelectric TES CAES: 70%
- Storelectric CCGT CAES hybrid: 80-85%
- Storelectric TES CAES / renewable generation system 80-85%

Battery advocates often quote efficiencies of 85%-97%, but these are battery-only performances with small-scale installations. Large installations require huge parasitic / ancillary loads, especially air conditioning. Northern Power Grid's Customer-Led Network Revolution, which concluded in December 2014, measured the actual round trip efficiency of battery systems at the beginning of their life[35]:

	2.5kVA, 5MWh	**100kVA, 200kWh**	**50kVA, 100kWh**
Cost excl. installation	£3.76m	£406k	£331k
£/MWh	*£752k*	*£2,030k*	*£3,310k*
Cost inc. Installation	£4.62m	£490k	£422k
£/MWh	*£924k*	*£2,450k*	*£4,110k*
Nominal efficiency	83.2%	86.4%	83.6%
Measured efficiency	69.0%	56.3%	41.2%
Average parasitic load	29.5 kW	29.5 kW	29.5 kW

In a recent public presentation, a senior manager of Belectric stated "it is well known that" a 5-year-old grid connected battery requires three times as much air conditioning load as an otherwise identical 1-year-old installation, due to the rate of deterioration of the battery. And that increase in cooling requirement is due to (and compounds) a decrease in cell efficiency. There is also substantial lifetime deterioration in inverter efficiency[36]. However there is little literature on this because the rate of deterioration depends on the temperatures and duty (load) cycles to which a battery is subjected, and because battery manufacturers like to keep these matters confidential and/or hidden.

---

[35] http://www.networkrevolution.co.uk/project-library/electrical-energy-storage-cost-analysis/ table p6. Efficiencies have improved since then, but the general point remains. The efficiencies this paper cites are grid-to-grid, mid-life efficiencies: batteries tend to quote much higher figures which apply to terminal-to-terminal measurement on day 1.

[36] https://energy.sandia.gov/wp-content/gallery/uploads/Flicker-PVSC-Cap-Paper-Final.pdf and https://www.ilumen.be/en/what-is-the-lifetime-of-an-inverter/

However there is little literature on this because the rate of deterioration depends on the temperatures and duty (load) cycles to which a battery is subjected – for example, an inverter may deteriorate over 20 years by 3% in Denmark but by 20% in Arizona[37].

As efficiencies have improved since the Northern Power Grid project, this analysis will base its calculations of day 1 efficiency on a 2019 report by the American National Renewable Energy Laboratory[38]:

- Day 1 efficiency = 85%, i.e. ancillary loads 15%
- Inverter load 5%, doubles over lifetime to 10%, average value 7.5%
- Cell cooling load 10%, triples over lifetime to 30%, average value 20%
- Average lifetime ancillary loads are therefore 27.5%
- Yielding an average lifetime efficiency of 72.5%

However the "unique selling proposition" of batteries is their speed of response – which also happens to be their least efficient mode of operation and the mode that makes them deteriorate fastest. Therefore we cite a 41-75% efficiency range.

The Danish Technical Institute's Forskel project (2016)[39] also analysed actual battery performance. The Executive Summary:

> "Generally, the batteries themselves have efficiencies above 95%, but auxiliary systems and losses in inverters and transformers can reduce the overall system efficiency to below 50% in low load operation."

In 5.2.5 (p36), the table shows the difference in efficiency η between battery efficiency (right-hand column) and system efficiency (middle column):

	Delivered energy [kWh]	Consumed energy [kWh]	η System [%]	η Ex. Aux. [%]	η Battery [%]
Peak (1/3 C)	53,3	66,3	80,3	85,3	98,2
Init. cycles 1/3C	54,2	95,6	56,8	66,5	93,9
Accelerated Avg. Day	201,9	263,6	76,3	82,6	96,3
Avg. Day	34,3	75,9	45,2	56,4	95,9

There is no comment about the additional cooling requirements or cell efficiency reduction of batteries (or of the compounding of these two factors) as they degrade; which, as Belectric stated (above), are three times that on day one. This is because the reduction in capacity is mirrored by efficiency losses, which manifest themselves as additional heat output.

[37] https://vbn.aau.dk/files/252873002/TPEL_Reg_2016_11_2129.pdf

[38] Cost Projections for Utility-Scale Battery Storage, https://www.nrel.gov/docs/fy19osti/73222.pdf

[39] https://www.energiforskning.dk/sites/energiteknologi.dk/files/slutrapporter/bess_final_report_forskel_10731.pdf

Appendix H: Storelectric Makes the Energy Transition Affordable

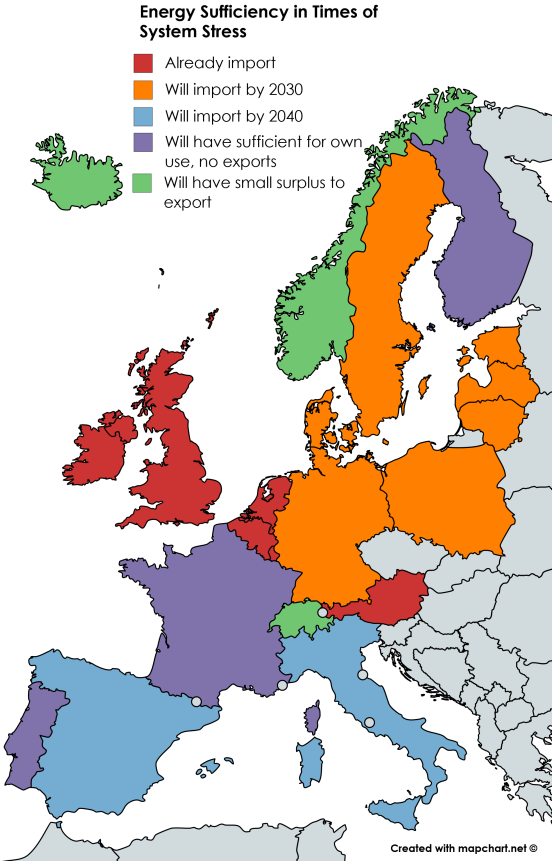
Storelectric has developed what they claim is the world's most cost-effective large-scale long-duration electricity storage technologies based on advanced forms of Compressed Air Energy Storage. These will greatly reduce the cost of the transition to a Net Zero grid, and of enabling the electricity system to help with the decarbonisation of heating, transportation and industry.

A Cheaper System
Intermittent renewables are currently balanced by dispatchable generation and imports. These incur a total cost of well over £2bn p.a. to the electricity system in overt (e.g. curtailment, Capacity Market), covert (e.g. rocketing total costs of balancing and ancillary services) and hidden (e.g. under-priced emissions) costs, rising rapidly. In a level regulatory playing-field, Storelectric's storage can deliver these services without subsidy.

Reduced Grid Reinforcement
Storage at such scale and duration can be located strategically, such as to take the electricity generated by offshore and onshore renewable farms. This would reduce the scale of peak load on the grid by half for wind and two-thirds for solar, thereby greatly reducing congestion and the costs of grid connections and reinforcement. The renewable farms would benefit equally from a reduction in their grid connection costs and access charges.

Correspondingly, if (say) 100MW of wind or solar is already connected to the grid, building 100MW of storage at such scale and duration would enable a further 100MW wind or 200MW solar generation to be added to the same grid connection.

Improved Reliability of Supply
The UK already depends on imports of electricity at "times of system stress", such as high demand and/or low renewable generation; so do Ireland, Austria and the Low Countries, together with much of the Eastern EU. According to their national energy transition plans, by 2040 these will have been joined by Denmark, Germany, Italy, Poland, Sweden and Spain (see map). France is relying on a 40GW nuclear build-out to be on-time and to-cost, on which the reader can make their own judgement.



Since these times of system stress (such as after dark on a windless winter evening) are largely concurrent across many or all of these countries, if all are importing, who is exporting? We therefore cannot rely on there being a surplus of energy to import, and leaving the Single Market (regulated by the European Court of Justice) will mean that our neighbours can legally tell us that their customers are more important to them than ours. Therefore black-outs will ensue if we don't have sufficient dispatchable electricity in the UK; large-scale long-duration storage is the most cost-effective way of achieving this.

Improved Grid Stability

As inertial generation (i.e. power stations) decrease, the grid is becoming increasingly difficult to keep stable – as was seen in the 9th August 2019 black-outs in the United Kingdom. Even apart from such extreme events, National Grid is developing all manner of new financial contractual and management instruments such as faster responses, Stability Pathfinder and initiatives in voltage, frequency and constraint management. All this is very expensive, not only in contractual terms but in administration and grid management too.

Storelectric's technologies both deliver twice the inertia and over six times the reactive power/load and related services of an equivalent-sized power station – and can do so 24/7. This greatly increases grid stability, making this plethora of instruments much less important and costly to run.

These plants can also be built to deliver black start, with the scale and inertia required to re-start entire sections of the grid.

Storelectric's Technologies

Storelectric has two main technologies and hybrid versions of them, namely:

- TES (Thermal Energy Storage) CAES, zero emissions, 70% efficient grid-to-grid, cheaper than alternatives.
- CCGT CAES is uniquely retro-fittable to a suitably located gas-fired power station, reducing emissions by a third and adding storage-related services, thereby re-lifing otherwise stranded assets. It is much cheaper, depending on the extent of re-use and refurbishment, and can be fully decarbonised later.
- Both technologies operate at scales of 20MW to multi-GW, and durations of 4+ hours. Both deliver all the services described above.

Both technologies are vastly cheaper per MWh than both batteries and pumped hydro, and able to be installed closer to both supply and demand than the latter. There is vastly more than enough geological capacity in the UK to provide a fortnight's back-up, sufficient to tide us through the *kalte dunkel Flaute* (cold dark doldrums), a 2-week weather pattern (high pressure in winter) during which renewable generation is low or negligible across most of the continent, occurring every couple of years – or much more frequently over more restricted geographical spreads or durations.

Low Risk Solutions

Both technologies are simplified versions of other technologies, and built entirely with standard equipment. TES CAES replaces the cooling tower, gas feed and gas combustion of the Huntorf and McIntosh CAES plants with thermal stores, the system and its capabilities having been validated by numerous multinational engineering and manufacturing companies. CCGT CAES is a minor modification of a CCGT power station (though it could also be retro-fitted to OCGT power stations), and also supported by analysis from engineering and manufacturing multinationals.

Working With Other Technologies

Storelectric does not see themselves as supplanting batteries, Demand Side Response and other such technologies, but as working with them. Mark Howitt, CTO and a co-founder, likens the electricity system supporting renewables to the road network supporting our lifestyles: with only motorways and trunk roads we couldn't get to our offices, shops and homes; with only small roads we couldn't get anywhere fast or far. All are needed, but they need to do the jobs for which each technology is optimal.

Time to Build

The main challenge they face is the time to build each plant, which is largely due to planning and grid connection lead times. A plant connected to the distribution grid will take about 3 years from finance to trading; on the transmission grid 7 years. This means that to minimise the cost of the energy transition, and to maximise the reliability and stability of the grid, the first plant needs building soon. Storelectric has scores of verbal expressions of interest in funding follow-on plants in the UK and across 5 continents; all they need is the finance to build the first.

Appendix I: The Lockdown – A Partial Test of a 2030s Grid

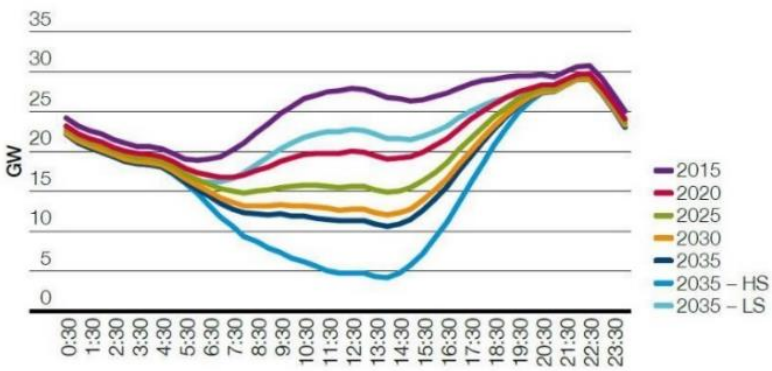
The lockdown provided a trial run of the "summer minimum" challenges of operating the grid as it will be in the 2030s and 2040s, with renewable generation as a high proportion of demand. Demand was historically low and renewable generation historically high on both the distribution and the transmission grids. Not only did this mean that electricity flows through the transmission grid dropped severely, but also inertia dropped to levels that required extensive intervention.

This reinforces the need for Storelectric's CAES to provide not only absorption of renewable energy when it exceeds demand, but also the real inertia and other related grid stability services that are currently being provided by gas-fired power stations. Storelectric's plants not only provide more inertia than an equivalent-sized power station, but also provide it 24/7 if needed.

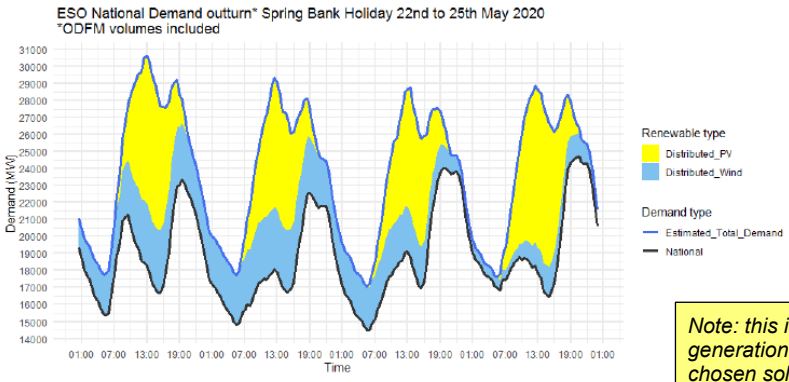
Minimum Energy Flows

In their Future Energy Scenarios 2015, National Grid declared that to keep the grid out of black-start conditions at least 5GW must flow through it. Based on then-known distributed solar generation, they believed that they risked dropping below this figure by 2035 in the worst-case scenario. However they had underestimated solar by 3GW and omitted to consider distribution-connected wind, so the first time they hit the 5GW threshold was actually in August that same year.

Figure 96
Consumer Power summer transmission demand across years



Bank Holiday Weekend (22nd to 25th May) | Demand Outturn



Date	Cardinal Point	Volume of ODFM enacted (increases ND) (MW)	National Demand inc ODFM (MW)	Dist. wind (MW)	Dist. PV (MW)
Fri 22nd	1B	NONE	**15390**	2321	0
May	3B	NONE	**16680**	3681	7330
Sat 23rd	1B	999	**14813**	2909	31
May	3B	1902	**16744**	3611	6530
Sun 24th	1B	792	**14500**	2522	173
May	3B	NONE	**16970**	2451	6340
Mon 25th	1B	NONE	**16845**	622	254
May	3B	1020	**16465**	1763	8170

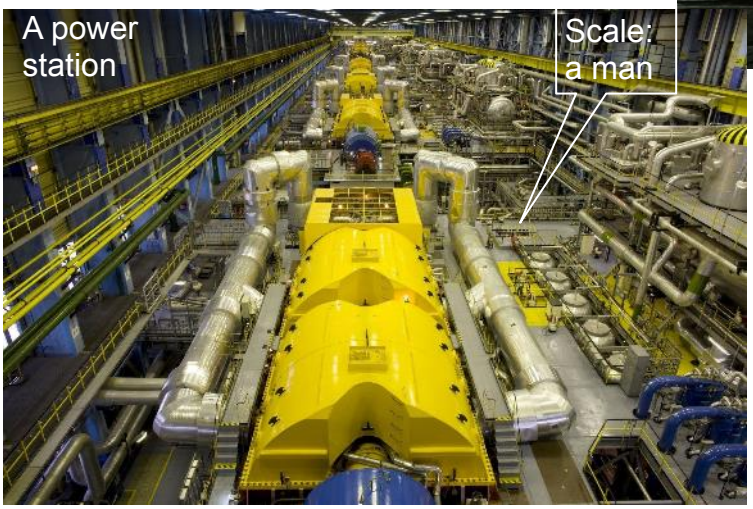
Note: this is not the period of highest renewable generation during the pandemic. This period is chosen solely because National Grid evaluated the costs of their actions for it.

nationalgridESO

During the COVID-19 Lockdown, demand has plummeted as a small increase in domestic consumption has fallen far short of a huge decrease in industrial and infrastructure (e.g. trains) consumption. Simultaneously the weather was perfect for renewable generation for weeks on end, with unseasonably strong sunshine combining with persistently strong winds. As a result, afternoon minima dropped below overnight minima on the transmission grid.

Inertia and Grid Stability

As fossil fuelled power stations continued closing during the last decade, it became apparent that they were providing many more services than just energy. Prime among these was inertia, with related capabilities such as real reactive power / load, ROCOF (Rate Of Change Of Frequency) and Phase Locked Loops – and many that are still more esoteric.

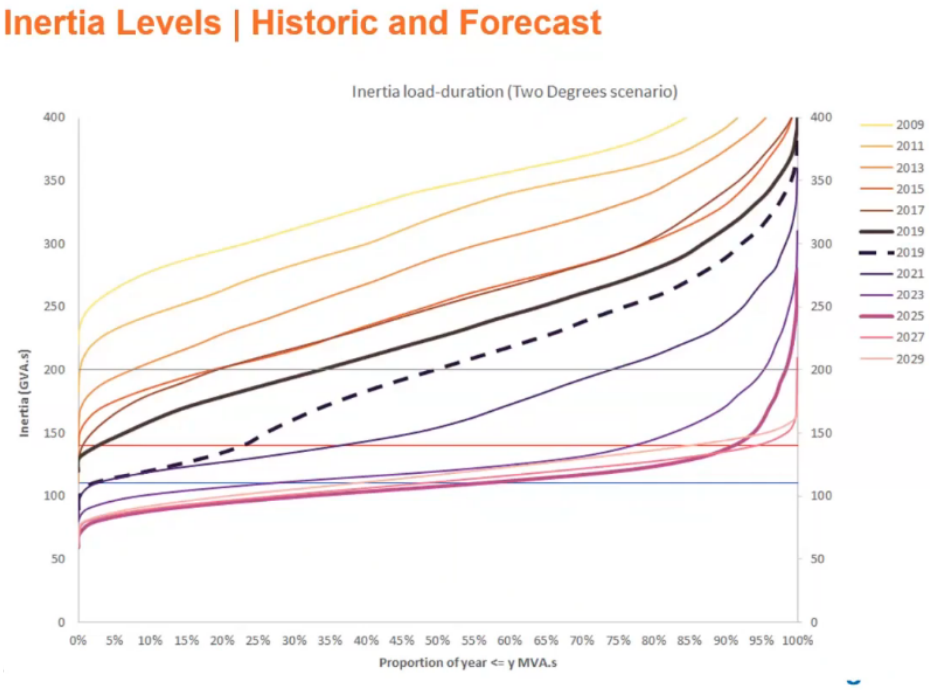


What is inertia? In a car, if the engine fails the weight of the car provides the momentum that means that it slows gently, enabling it to come to a save halt. Those in the car are protected. Without that momentum, the slow-down following the engine fault would be like hitting a brick wall. Inertia is momentum for rotating machines: power stations, being large rotating machines, have it in abundance whereas DC connected systems (including solar and wind generation, and interconnectors) don't.

Therefore as power stations close, replaced by DC-connected generation, inertia drops alarmingly. The fundamental cause of the black-outs across the UK on 9th August 2019 was that two initial trips, one in a power station and the other in a wind farm, turned into a cascade of subsequent trips around the country because there was insufficient inertia on the grid.

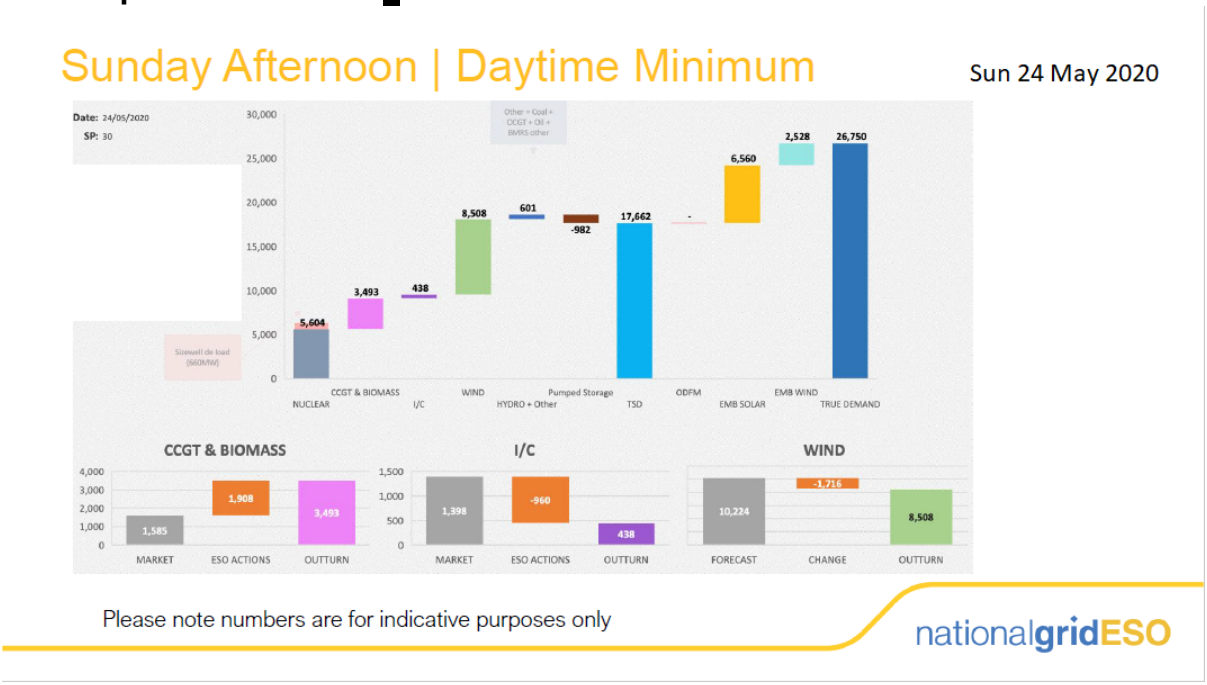
And inertia is dropping very fast: this graph shows how it's decreased over the last decade 2009-19, and is expected to continue to decrease 2020-29. National Grid

2009 2019 2029



has initiated many [investigations and activities](#) into these, including a number of [new contract types](#) and pathfinder activities (in the yellow box on the right of the first link) in order to contract for these stability services. All versions of Storelectric's CAES can provide all these services 24/7, regardless of whether charging, discharging or neither.

Consequences for Grids



Therefore National Grid had to undertake a number of actions to preserve grid stability. These include:

1. Pay to increase 1.9GW contracted interconnector imports to 3.2GW
2. Pay for 5.0GW curtailment of wind
3. Pay to turn down nuclear ~0.7GW

4. Pay to turn on 3.4GW power station generation
5. Various other actions

The total cost of these, over a bank holiday weekend, was £51m:

Costs of Managing the Bank Holiday Weekend 22-25 May 2020

Very low demands with low synchronous generation mix

	Friday 22nd May	Saturday 23rd May	Sunday 24th May	Monday 25th May	Total
Overnight Minimum Demand*	15.4 GW	14.8 GW	14.5 GW	16.8 GW	-
Daytime Minimum Demand*	16.7 GW	16.7 GW	17.0 GW	16.5 GW	-
Overnight ODFM Instructed Volume	-	999 MW	792 MW	-	-
Daytime ODFM instructed Volume	-	1,902 MW	-	1,020 MW	-
Balancing Mechanism Costs	£16,000k**	£14,249k	£7,073k	£2,152k	£39,474k
Trading Costs	£600k	£1,420k	£1,624k	£466k	£4,110k
ODFM Costs	-	£4,700k	£1,400k	£1,200k	£7,300k
Total	£16,600k	£20,369k	£10,096k	£3,818k	£50,833k

These costs represent the impact low synchronous generation mix during a normal low demand weekend combined with the suppression of demand brought about by COVID-19. The demands this weekend were some of the lowest expected this year.

nationalgridESO

*These demands include the additional demand from the ODFM service, **Constraint costs higher on Friday due to fire under a Transmission line
Please note that these numbers are subject to change.

And this was not the weekend with and greatest actions, as solar was not very high. *And these costs exclude increased imbalance costs and trading price volatility*, the total of which are likely to be considerably higher. Not only is all of this activity exceedingly expensive, but also it increases the grid's emissions. All of this would be completely unnecessary if there were sufficient of Storelectric's CAES on the grid.

And in the 2030s and 2040s?

By the 2030s and 2040s, more power stations will have closed – they may not even be available to be turned on if needed. Interconnectors and DC connected generation will have at least doubled in importance. this situation will be much more frequent – indeed, it is likely to be the normal state of affairs in summer, and quite usual in spring and autumn.

In early June 2020, demand suppression was 11.9%, yielding a carbon intensity of 46g CO_2e/kWh. The annual cost of National Grid actions May-September (5 months) is forecast to be £831m for 10% demand suppression. If similar proportions of renewable energy were to be delivered without demand suppression, the cost would be £831m divided by 90% = £923m. Extrapolating, the balancing costs of a 2040 grid would be £1bn p.a. for those five months alone – assuming (rashly) that sufficient gas-fired power stations will still be available and will remain as cheap by then. This is a rash assumption as they will generate much less electricity per annum than today, so all their annual running costs and amortisation etc. will need to be recovered over such services alone, increasing the price of those services. And note

that these costs are for only the peak 5 months in the year. For such services, it can therefore be predicted that ***year-round costs will exceed £1bn p.a. by 2030.***

To the above "summer minimum" issues can be added the lack of electricity on the grid when renewables are not generating sufficient for demand and interconnectors cannot make up the shortfall, such as after sunset on a windless winter evening, or during weather patterns that extend such low-generation period to days or weeks – which will also be a frequent occurrence by the 2040s according to most European countries' energy transition plans. These are the subject of a separate brief.

National Grid provided the following estimates of the costs of summer flexibility with 5, 10 and 15% demand suppression – probably best considered as renewables being a much greater percentage of demand to those degrees. This falls far short of the costs that would arise in a 100% renewable grid. Just for these low levels of renewable penetration, costs are forecast in the range £592m – £725m for the 4 months (£742m – £911m including September).

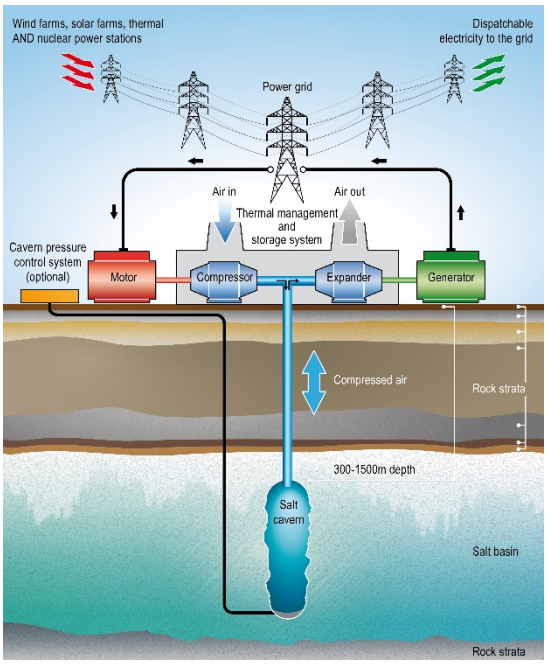
Month	Outturn 2019 (£m)	Pre-Covid Forecast Baseline (£m)	15th May Forecast (15% -20% suppression) (£m)	5% Demand Suppression (£m)	10% Demand Suppression (£m)	15% Demand Suppression (£m)
May	64.4	121.3	166	[163]	[163]	[163]
June	89	103.8	207.7	129.8	147.2	166.5
July	71.7	110.4	214.9	139.7	160.0	183.1
August	108.7	120.2	217.7	160.1	185.3	212.3
Total	**333.2**	**455.7**	**826.3**	**592.6**	**655.5**	**724.9**
Sept		115.1		149.6	165.6	185.8

Appendix J: About Storelectric and the Author

About Storelectric

Storelectric (www.storelectric.com) is developing transmission and distribution grid-scale energy storage.

- Innovative adiabatic Compressed Air Energy Storage (TES CAES). Our 500MW, multi-GWh installations will have zero/low emissions, operate at 68-70% round trip efficiency, levelised cost significantly below that of gas-fired peaking plants, and use existing, off-the-shelf equipment.
- Their CCGT CAES technology converts and gives new economic life to gas-fired power stations, halving emissions and adding storage revenues. Addresses the entire energy trilemma: the world's most cost-effective and widely implementable large-scale energy storage technology, turning locally generated renewable energy into dispatchable electricity.



Both technologies will operate at scales of 20MW to multi-GW and durations from 4 hours to multi-day. With the potential to store the entire continent's energy requirements for over a week, potential globally is greater still. In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES, all of which will greatly improve storage cost, duration, efficiency and global potential.

About the Author

Mark Howitt is Chief Technical Officer, a founding director of Storelectric. He leads Storelectric's technical and operations, minimising technological risk, maximising efficiency and environmental friendliness, and speed to market. He focuses on technologically simple solutions using proven technologies wherever possible.

His degree was in Physics with Electronics. He has 12 years' management and innovation consultancy experience world-wide. In a rail multinational, Mark developed 3 profitable and successful businesses: in commercialising a non-destructive technology he had innovated, in logistics and in equipment overhaul. In electronics manufacturing, he developed and introduced to the markets 5 product ranges and helped 2 businesses grow strategically.