Grid-scale electricity storage
using an innovative form of
Compressed Air Energy Storage

Matching the Solution to the Problem

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Contents

Introduction

This analysis builds on the improvements of the 2017 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 retained the two scenarios that are legally compliant to the Climate Change Act 2008, which offer two extremes of compliant system: centralised and de-centralised. To this they have added the beginnings of a Net Zero scenario based on adding some features of Community Renewables to a more ambitious version of Two Degrees, and excellent analysis in a short time since the Net Zero legislation.

We believe that the only scenarios that should be in future FES are these three, and other variants on Net Zero, as being the legally compliant outcome and two near-miss variants. Any planning done on the basis of the other two scenarios is, we believe, of dubious legal merit as such planning would be building a system that is designed to break the law.

Forecasts for most of the technologies are much more realistic, for example:

- Nuclear power is delayed and reduced in expected volume;
- CCUS has been put out until 2030 at the earliest, and eliminated entirely in two scenarios, to reflect (at least in part) its high costs and low efficiencies, though without recognition of the insurance problem;
- V2G (vehicle-to-grid) expectations have been reduced, in recognition of the fact that vehicles will only be able to spare 2 hours'-worth of charge at most, and of the commercial and technical complexities involved;
- There is, at long last, recognition of the need for large amounts of large-scale long-duration electricity storage.

We hope that this last point will lead to regulatory, legislative and TSO / DSO actions to encourage and incentivise the construction of such storage, including first-of-a-kind (FOAK) plants of new technologies.

Conclusion

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

1.

The Scenarios

We will ignore the two scenarios which do not comply with the Climate Change Act 2008 (CCA), because the recent Net Zero Carbon Emissions Act (NZCEA) places a legal obligation on the industry to exceed even the targets of the CCA. In response, National Grid have outlined the beginnings of a Net Zero scenario; we believe that there should be two or three of these.

Community Renewables

This is one of the two scenarios compliant to the CCA, but not to the NZCEA. Community Renewables is based on a distributed energy system and individual (as opposed to centralised, corporate) responses to the energy transition.

Generation is largely (58% by 2050) distributed, with small scale generation (including large growth in onshore wind) coupled widely with storage at that same distributed scale. The scenario concludes that little large-scale long-duration storage is needed, relying on a huge uptake in batteries (despite the scarcity of the elements, and the short duration of the batteries) whereas in reality all distributed systems rely on the grid for back-up. Without substantial such storage on the grid, what can provide that back-up? Therefore a distributed system needs as much large scale long duration storage as a centralised system, though it would use such storage less frequently and would therefore have to pay for its availability by some other means such as a version of the Capacity Market – that is, subsidies by another name.

The biggest savings are presumed to come from a 26% reduction in domestic energy storage, which presumes widespread financial incentivisation of energy efficiency in homes and appliances, and probably also penalisation of inefficiency.

The biggest leap of faith is a reliance on "green gas" (artificially created methane, electrolysed hydrogen, anaerobically produced syngas etc.) for 46% of the gas supply, which is a great leap of faith in a series of technologies that are neither proved nor cost-effective at such scales, and their paths to cost-effectiveness are uncertain.

By 2050, 22% of forecast 223GW generation capacity (versus 108GW today) is micro, and a further 36% distribution connected, leaving only 42% transmission connected. Peak demand increases to ~72GW (~62GW today), largely limited by peak avoidance using heat storage, which has yet to be come viable for widespread roll-out..

There is no CCUS (Carbon Capture, Use and Storage) in this scenario, reflecting its high capital and operational costs, its need for the carbon price (even for the most attractive possible installations) to be well above $60/tonne, and the (so far) all-defeating insurance challenge.

Two Degrees

This also complies with the CCA, but not to the NZCEA. Heating is largely by electrolytically produced hydrogen, and both smart technology and demand side actions reduce peak demand. Nevertheless, this yields the highest demand of the four main scenarios (peak ~115GW), though exceeded by the Net Zero scenario. Smaller vehicles are electric, larger ones hydrogen powered by 2050.

Generation moves largely to offshore wind and nuclear. Large scale storage is developed, with great reliance also on interconnectors. Widespread use of carbon capture and storage is envisaged, for flexible generation and for producing hydrogen by steam reformation.

By 2050, 9% of the forecast 2218GW generation capacity is micro, 29% distribution connected and 62% transmission connected. Peak demand increases to ~83GW (~62GW today), largely limited by peak avoidance for charging vehicles.

A huge hydrogen industry is envisaged to supply both gas into the gas network and fuel for the fuel cells forecast for heavier-use vehicles. This industry is forecast to increase electricity demand from 2030, to achieve ~40% of total demand by 2050.

Steady Progression and Consumer Evolution

These are the two legally non-compliant scenarios, and therefore not the main focus of this analysis. Both envisage widespread changes towards EVs with smart chargers that therefore are assumed to have minimal effect on grid peak demand; neither envisages widespread roll-out of hydrogen technologies for either heating or transportation. Both envisage development of significant amounts of nuclear generation, and both keep similar gas consumption to the present day, while accommodating some change in source – largely from domestic offshore production and towards shale gas. Steady Progression relies on lots of CCUS, while Consumer Evolution has none.

Net Zero

This is probably the most important scenario, not developed in full because there was insufficient time to do so between the passage of the NZCEA and publication of FES 2019. Given that challenge, it's an excellent first attempt.

Net Zero starts with Two Degrees. CCUS is essential, primarily in conjunction with biomass generation (BECCS) in order to provide for negative emissions to balance positive emissions elsewhere, such as the generation of hydrogen by methane reformation – as CCUS is only ~80% efficient at capturing emissions (costs rise exponentially with percentage), it produces significant amounts of emissions that need to be balanced by BECCS.

Buildings at all types have to be much more efficient than even in the Two Degrees scenario. Domestic gas boilers are eliminated (they are only reduced by >75% in Two Degrees and Community Renewables). Electrification for heat pumps, industrial processes etc. increases greatly, and therefore electricity demand; and because the geographical pattern of that demand changes so rapidly the electricity transmission and distribution systems will need considerable investment.

Because of increased electrification, 263GW generation is needed – significantly above all other scenarios. This is largely intermittent, which implies the greatest need for storage. There is no forecast for peak demand.

Total Demand

One vast improvement over previous years' reports is that, whereas prodigious amounts of energy just "vanished" from the plans (approaching twice as much vanished energy as total forecast electricity demand), this year the vanished consumption looks achievable:

Community Renewables - Change in total demand in year (TWh)				
	2018	**2030**	**2040**	**2050**
Gas (from 4.1)	804.0	226.8	343.2	204.4
Petrol/Diesel (from 4.18)	487.6	329.2	101.9	0.1
Electricity (from 4.1)	284.8	282.9	354.3	412.8
Total	1,576.4	838.9	799.5	617.3
Decrease (cumulative)		-737.5	-776.9	-959.1
Decrease (cumulative %)		-47%	-49%	-61%

Two Degrees - Change in total demand in year (TWh)				
	2018	**2030**	**2040**	**2050**
Gas (from 4.1)	804.0	241.8	353.9	208.9
Petrol/Diesel (from 4.18)	488.2	335.5	117.1	0.1
Electricity (from 4.1)	284.8	309.5	530.4	749.6
Total	1,577.0	886.8	1,001.3	958.6
Decrease (cumulative)		-690.2	-575.7	-618.5
Decrease (cumulative %)		-44%	-37%	-39%

This total system energy reduction is achieved by energy efficiency of (for example) domestic consumption, heat pumps and electric vehicles.

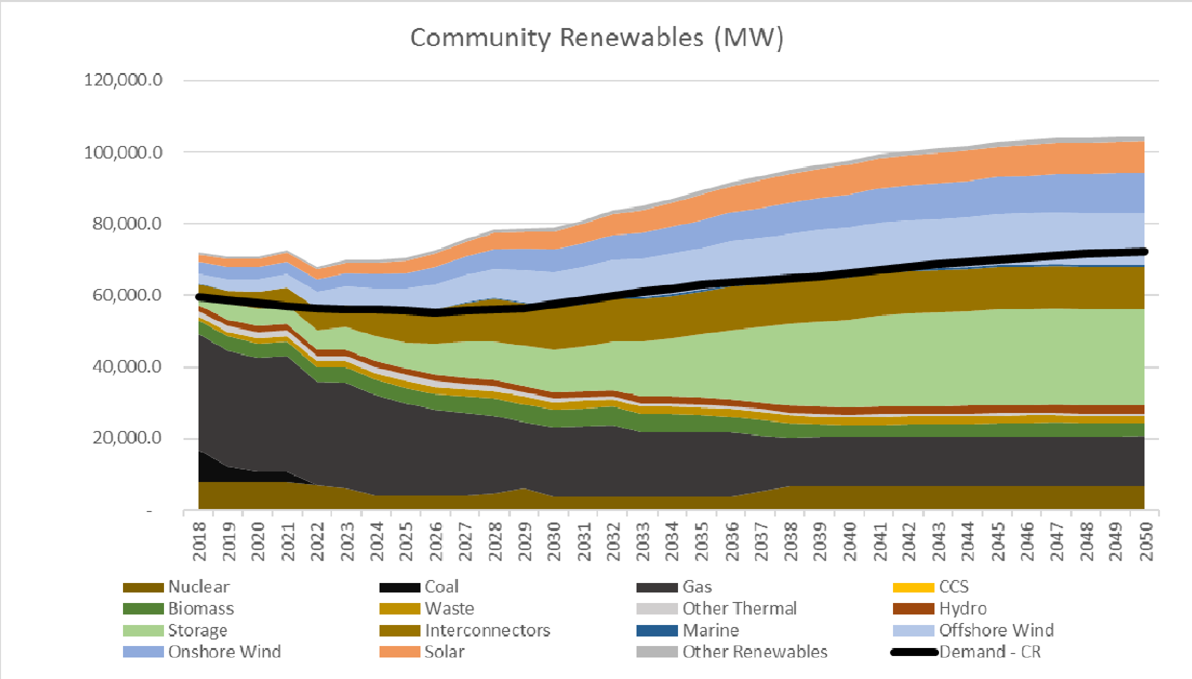
However it should be treated with extreme caution as there are also very substantial changes that decrease energy efficiency in the whole system, e.g.

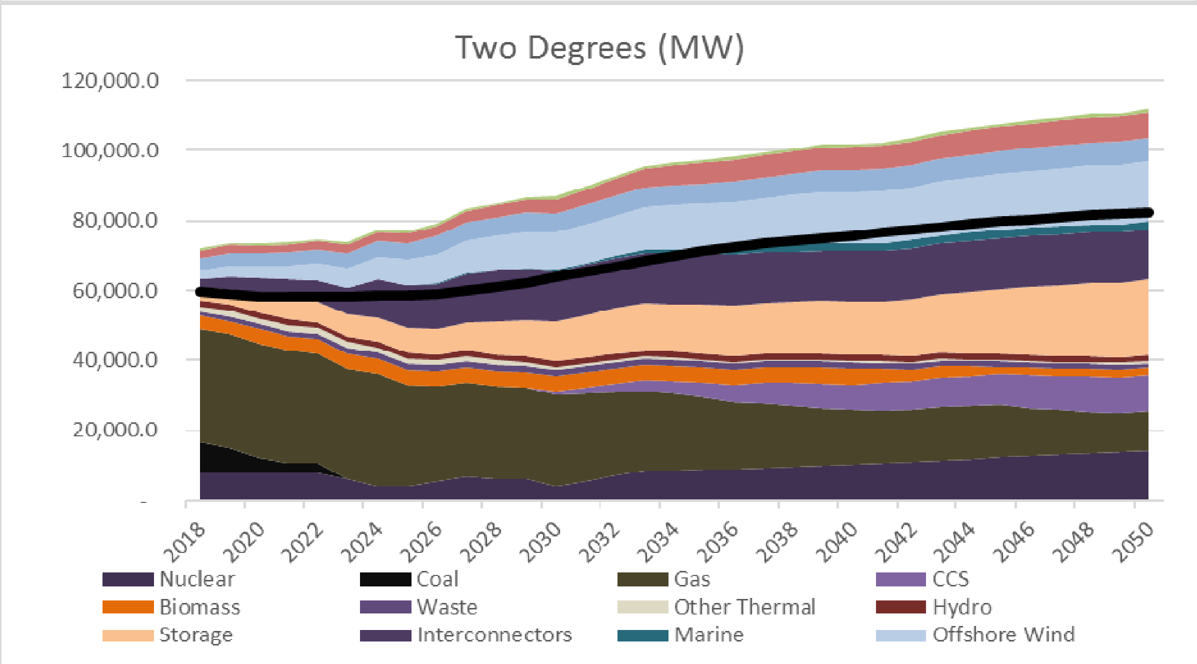
- Hydrogen production is necessarily energy inefficient, whether by methane reformation or electrolysis;
- Hydrogen transportation through the gas grid is more energy intensive as it carries about one-third of the energy per m^3 of the gas;
- Autonomous vehicles will lead to a significant increase in total mileage;
- 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.

Generation Mix

In FES 2019, energy supply is from the following technologies:

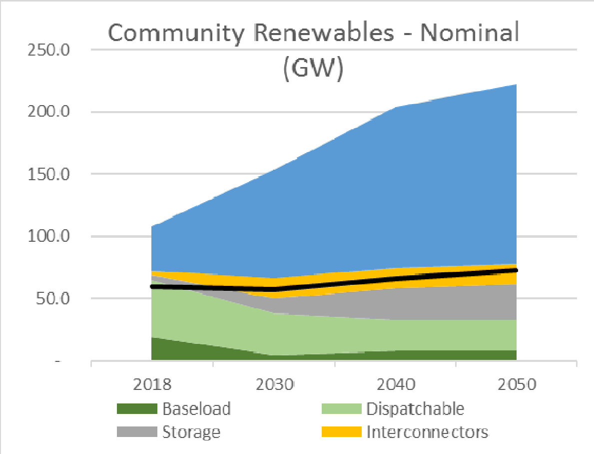


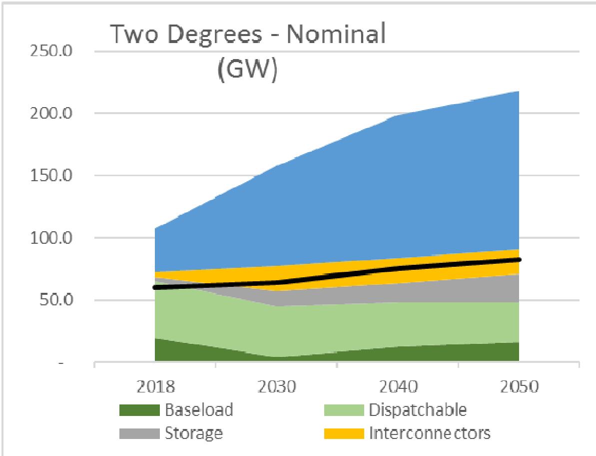


The above graphs are all FES 2019 figures, with the bars re-sequenced to show baseload[1] at the bottom, then dispatchable[2], then interconnectors, and finally (in decreasing sequence of reliability) intermittent generation. These are listed by de-rated nominal capacity: as discussed elsewhere, duration of storage is not reflected in these figures. Storage should be represented by 2 bars, short-duration (<2 hours) and long duration, in order to get a good understanding of the energy system. These graphs can be summarised as:

[1] Baseload = nuclear, coal
[2] Dispatchable = hydro, waste, gas, CCS, other thermal, biomass, storage

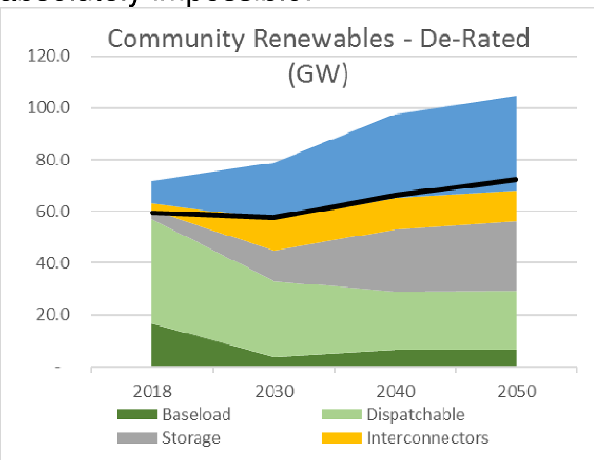
These can be summarised like this:

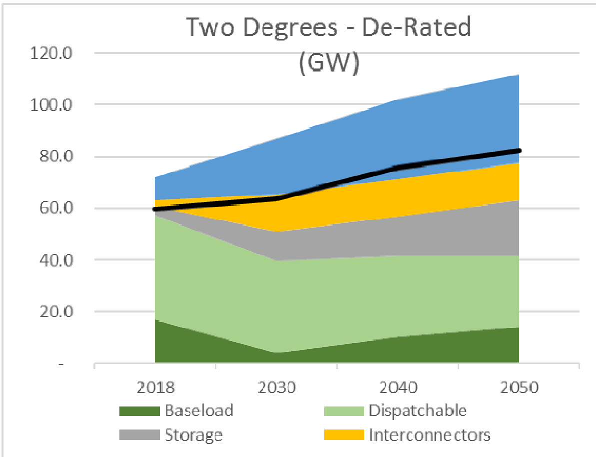




This looks like a serious risk: the country is depending on imports for actual demand, without even taking into account either supply margin (10-15% to be added to demand) or the lack of duration of most of the storage concerned.

However, when de-rating factors[3] are applied to the generation mix, it looks absolutely impossible:





Actual demand, excluding both the above factors, exceeds the country's capacity both to generate and to import. Even assuming that imports are available, which is highly unlikely during times of system stress.

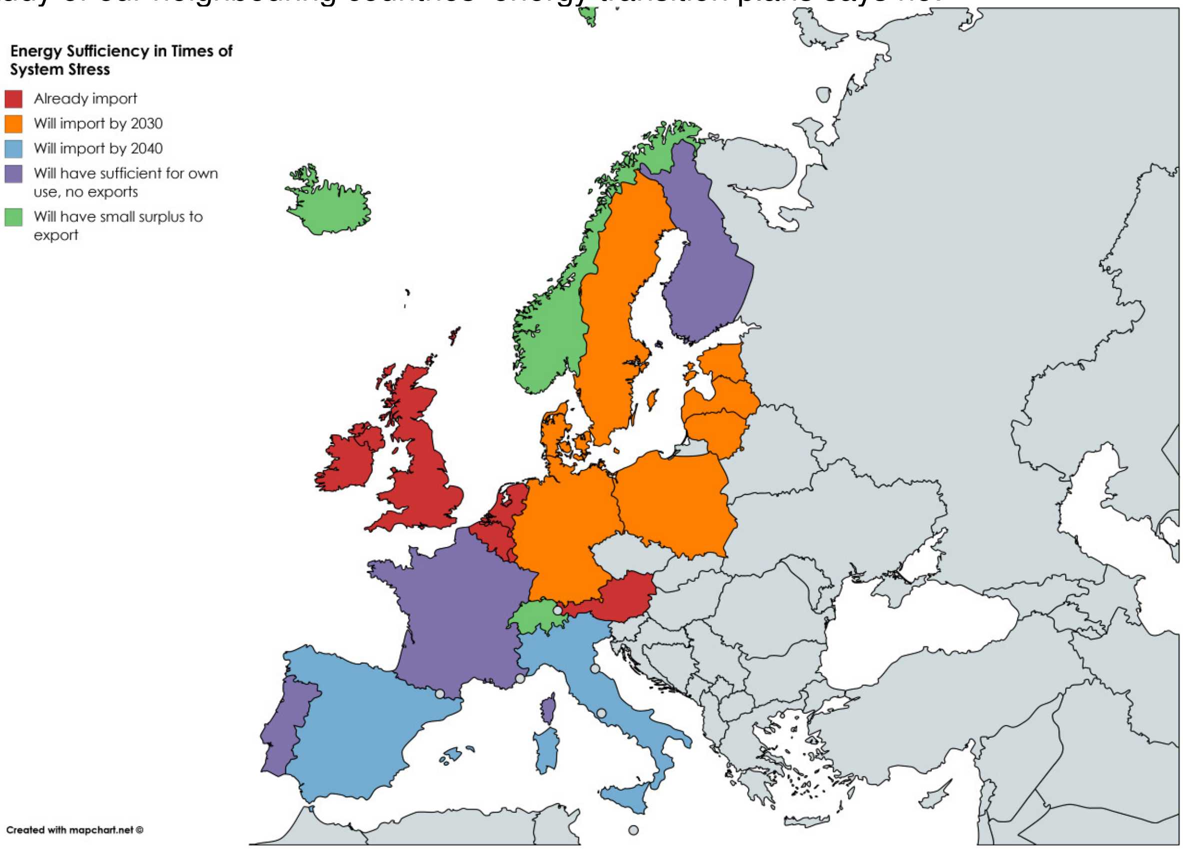
[3] De-rating factors for biomass, coal, gas, hydro, interconnectors, nuclear, storage, energy from waste, using T-1 de-ratings, section 1.3 (p6): https://www.emrdeliverybody.com/Lists/Latest News/Attachments/114/Capacity Market Auction Guidelines July 7 2017.pdf
De-rating factors 2017 for wind, DUKES 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
De-rating assumptions: CCS = gas CCGT; Other Thermal = coal; Waste = biomass; Marine = 60%; Other Renewables = onshore wind
Note: National Grid's assumption is that Vehicle to Grid (V2G) is as reliable as batteries, whereas in reality vehicles are often not available.

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 dunkel Flaute"* (cold dark doldrums) 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.

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.

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 in both Two Degrees (to 15GW by 2035, 23GW by 2050 and continuing to grow) and Community Renewables (to 25GW by 2038, then much more slowly thereafter, reaching 28GW by 2045) – see Figure 5.11. These are very necessary volumes of storage, showing a recognition of need that is much more realistic than previous FES analyses.

But again there is no mention of duration: 30-minute batteries are considered equal to pumped hydro and CAES that have multi-hour and even multi-day durations. There is a bald statement that "in the Two Degrees scenario … more of these projects are bigger, longer duration…", but 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. The 2015 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).

Net Zero requires an increase of 20GW intermittent generation without looking further to see the amount of storage that is required to make it dispatchable or baseload.

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

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

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).

De-Carbonisation

It is good that two scenarios assume that the UK adheres to EU decarbonisation targets despite Brexit, and Net Zero exceeds them. 80% emissions reductions are treaty commitments of the UK separate from our EU membership and therefore will remain after Brexit; they are also a measure of the country's good global citizenship, and we must expect to have to adhere to them for future good relations with our trading partners regardless of Brexit provision. Happily, Net Zero legislation commits the country to zero emissions, well below the Paris Accord targets, showing the country to be a good world citizen, taking responsibility for having created so much of the world's emissions since the industrial revolution. 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).

Unfortunately this year there is no analysis of the expected carbon intensity of electricity; last year'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]. While the material used may be waste, 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.

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. Recently, however, 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

Both Community Renewables and Two Degrees forecast a phasing out of virtually all petrol fuelled vehicles, and a negligible number fuelled by natural gas. Both scenarios correspond with a 70% reduction in total energy consumption for transportation, which is achievable given the greater on-vehicle energy efficiency of electric and hybrid motors, even when accounting for small (possibly inadequate, but that's debateable) increases in mileage due to autonomous vehicles.

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, 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.
- 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. Distribution grids need upgrades at enormous cost and ahead of actual demand in order to accommodate variability between forecast and actual EV take-up.
7. 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[7]. Cobalt and other "rare earth metals" are in much shorter supply.

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[8], which has to be applied twice – once for charging and once for

[7] 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

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

discharging. The total round trip efficiency is therefore .85 x .9 x .9 = 0.6885 or 69% round trip.

(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%[9].)

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

Both scenarios envisage massive growth in the use of hydrogen, for both the gas grid and hybrid vehicles. 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[10]. Combustion yields 286kJ/mole[11] = 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 inefficient for use in electricity generation, so the place of hydrogen is in the gas grid and for fuel cells (50-60% efficient[12]).

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[9] 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
[10] https://www.quora.com/How-much-electricity-is-needed-to-produce-hydrogen-from-water
[11] https://www.quora.com/How-many-kWh-can-you-get-from-burning-1-litre-of-hydrogen-gas
[12] https://www.hydrogen.energy.gov/pdfs/doe_fuelcell_factsheet.pdf using Google's cached version as the original had moved

As stated verbally in the conference, FES 2019 envisages 75% of hydrogen coming from methane reformation, and 25% from electrolysis in all its forms.

- Methane reformation adds enormously to total system cost, not only due to the need for CCUS to be added to each plant, but also to the need to build BECCS to balance out the residual 20% of 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 25% to 75% by 2050 (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.

It is worth questioning the figures in FES 2019 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.

Nuclear

Although nuclear expectations have wisely been reduced and delayed since 2017, and plans have switched largely from large nuclear power stations to Small Modular Reactors (SMRs), they still seem to be rather optimistic. 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[13]. The current 3.2GW plant was approved in 2007 for commissioning by 2017[14]. The latest delay puts the forecast commissioning date as 2027 and cost at over £20bn and £30bn subsidies through electricity bills[15] – the scenarios expect it to come on stream in 2026, a year ahead of current expectations and without provision for any further schedule slippage. As all but one current nuclear power stations should retire by 2030, this entire forecast is based on a total of 19GW new power stations with a forecast capital cost of £70bn[16] – which the current Hinkley Point C cost calls into question.

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-

[13] https://en.wikipedia.org/wiki/Hinkley_Point_C_nuclear_power_station#1980s_PWR_proposal
[14] http://www.telegraph.co.uk/business/0/hinkley-point-c-new-nuclear-plant-timeline-of-the-story-so-far/
[15] http://www.telegraph.co.uk/business/2017/07/03/hinkley-nuclear-costs-climb-almost-20bn-start-delayed/
[16] http://namrc.co.uk/intelligence/uk-new-build-plans/

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 $60 to above $240 per tonne. 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.

Carbon Capture, Use and Storage

These scenarios do well in reducing and delaying expectations of carbon capture and storage (the report considers its use too – CCUS rather than CCS, though no commercially viable use has yet been found for such quantities of CO_2). Nevertheless CCS remains unaffordably expensive, much more so than nuclear: £27bn p.a. plus capital costs for 8MW abated coal fired power stations, without allowing for the inefficiencies introduced into the power generation process, according to aspirational figures from DECC's website which they removed when cancelling the two CCS power station projects in 2015. The introduced inefficiencies increase coal burn by around a quarter[17], raising its levelised cost of energy to well above that of other generation technologies[18].

Moreover, the In June 2017 the Americans cancelled the Kemper coal gasification and CCS project when its capital cost for a 582MW plant exceeded $7.5bn[19], 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?

Usage 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. The UK parliament has released a briefing on this[20]. Therefore usage does not carry promise of major CO2 emissions reduction in the near future, so the principal target for national emissions reduction must remain CCS.

Flexibility

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

Storage Revenues and Mix

[17] http://www.world-nuclear.org/information-library/energy-and-the-environment/clean-coal-technologies.aspx (see table 1)
[18] 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
[19] https://en.wikipedia.org/wiki/Kemper_Project and https://www.smithsonianmag.com/smart-news/major-clean-coal-project-mississippi-shut-down-180963898/
[20] https://researchbriefings.parliament.uk/ResearchBriefing/Summary/POST-PB-0030 ("CCC Report")

Revenue Stacks: FES 2019 is 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[21] 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 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[22] which tends to be their main justification and business case. Other studies show that they are much less efficient (grid-to-grid) than advertised[23].

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, 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).

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

[22] 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

[23] 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

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 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

Demand Side Response (DSR) is included in the FES 2019 analysis, but there is no way of identifying its magnitude, importance or use. Therefore the following comments relate to the 2018 report, which does discuss it explicitly.

The two 2050 compliant scenarios are expected to offer about twice as much demand side response (DSR) as the other two scenarios. Roughly, industrial DSR (p60) is forecast at 1GW for all scenarios, doubling to 2GW for the non-compliant scenarios by 2040 (then remaining constant) and 4GW for the compliant ones by 2050. No residential DSR is proposed.

FES 2018 then takes these figures as being the available to reduce peak demand on the grid, which is not wholly the case. This is because if a process is turned off/down now, then it cannot be turned off/down again within a few hours: the business has to be able to conduct its business. DSR is a short duration solution that is best used for absorption of short duration spikes in demand / short term troughs in generation. Therefore these DSR volumes need to be split into multiple “packets” because the nature of both variable demand and intermittent supply is to provide multiple such spikes within those few hours. It is therefore reasonable to split DSR into, say, 3 “packets” of (for the compliant scenarios) roughly 1.5GW, 1.5GW and 1GW. Therefore the maximum benefit to meeting actual demand is 1.5GW.

There is another issue not accounted for: compensatory peaks (bounce-backs) in demand after the DSR period is finished. If, for example, a heating process is switched off/down for 15 minutes, then at the end of that period heating demand will be above the norm in order to get the process back up to the correct operating temperature. The same applies for refrigeration processes. This reduces the benefit of DSR: if it is used in a peak demand period, then the compensatory peak is also during the same peak demand period.

The scenarios are more realistic about the benefits to the system of Time of Use Tariffs (p69), though we believe that use of them will be significantly below even these current forecasts due to (a) not wanting to be bothered with active management of energy consumption as the much-touted 2% target savings are simply not worth the effort for most people, and (b) not wanting to out-source such active management by connecting appliances and systems to the internet, for reasons of both autonomy and fear of hacking. However we have no alternative figures to offer or studies to cite, so will make nothing more of this point.

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 since 2010, 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[24].

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

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.

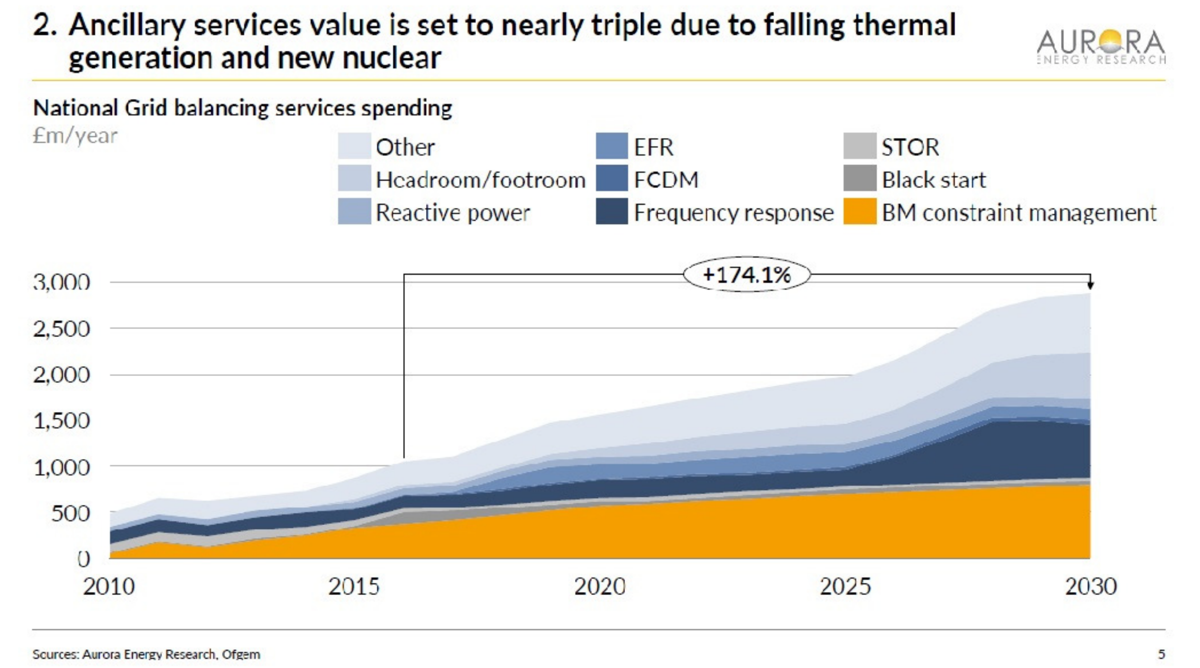
[24] More details available in a Storelectric white paper Curtailment: the Tip of a Growing Iceberg, available on request

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[25], "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"[26]. 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"[27]. This supports Aurora's analysis in 2016, whose figures have largely been borne out in practice:



25 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf
26 Spotlight, p63
27 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.

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

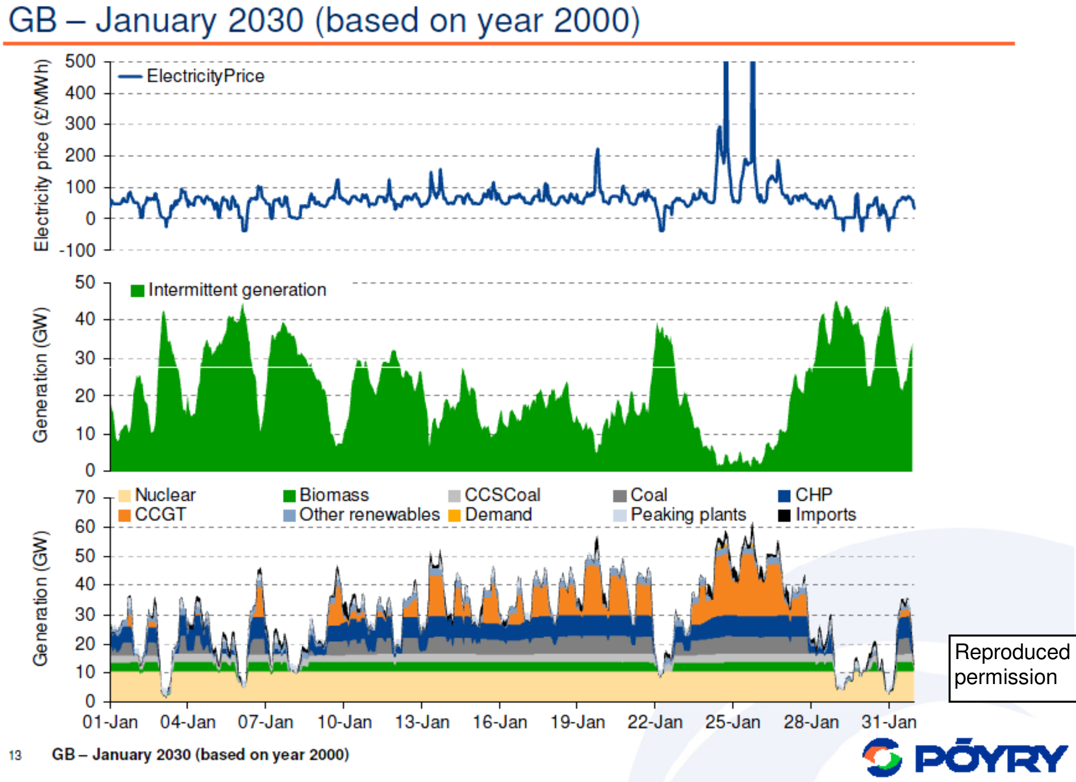
for grid connections, and to enable contracts to be let for storage services (see Appendix E for more details);

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:



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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[28] 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.

[28] 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[29], 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"[30] even though Belgium was the first country in Western Europe to be planning openly for rolling black-outs[31] to make up for potential generation shortfalls, and Belgium's interconnection capacity is 3.5GW, or 25% of their 14GW peak demand[32], as compared with Britain's current 4.15GW, or under 7% of peak demand.

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

[29] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013 p41-44
[30] www.nationalgrid.com
[31] http://datafable.com/rolling-blackout-belgium/viz/
[32] http://energy.sia-partners.com

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.”

“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.

Because of their function in lowering overall energy prices and making up for domestic energy shortfalls, Storelectric’s CAES does not supplant the need for interconnectors, but works with them. Indeed, CAES at either end of one could increase the energy transported by that interconnector by up to 6 times, depending on the energy profile at either end of the interconnector. Like CAES, interconnectors are therefore not the solution, but an important part of the solution.

Interconnectors and Brexit

Currently Britain is in the single market, regulated by the European Court of Justice. This ensures that if we pay enough, our neighbours have to sell us the electricity, and to do so tariff free. According to FES 2017, “our analysis currently assumes tariff free access to EU markets under all scenarios.[33]" This is the rosiest possible scenario, which is therefore a very rash assumption – and the more so as the government has consistently said that we will leave both the single market and the jurisdiction of the ECJ. Worse, this means that all our neighbours would then be free to tell us that they prioritise their consumers at any price.

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".

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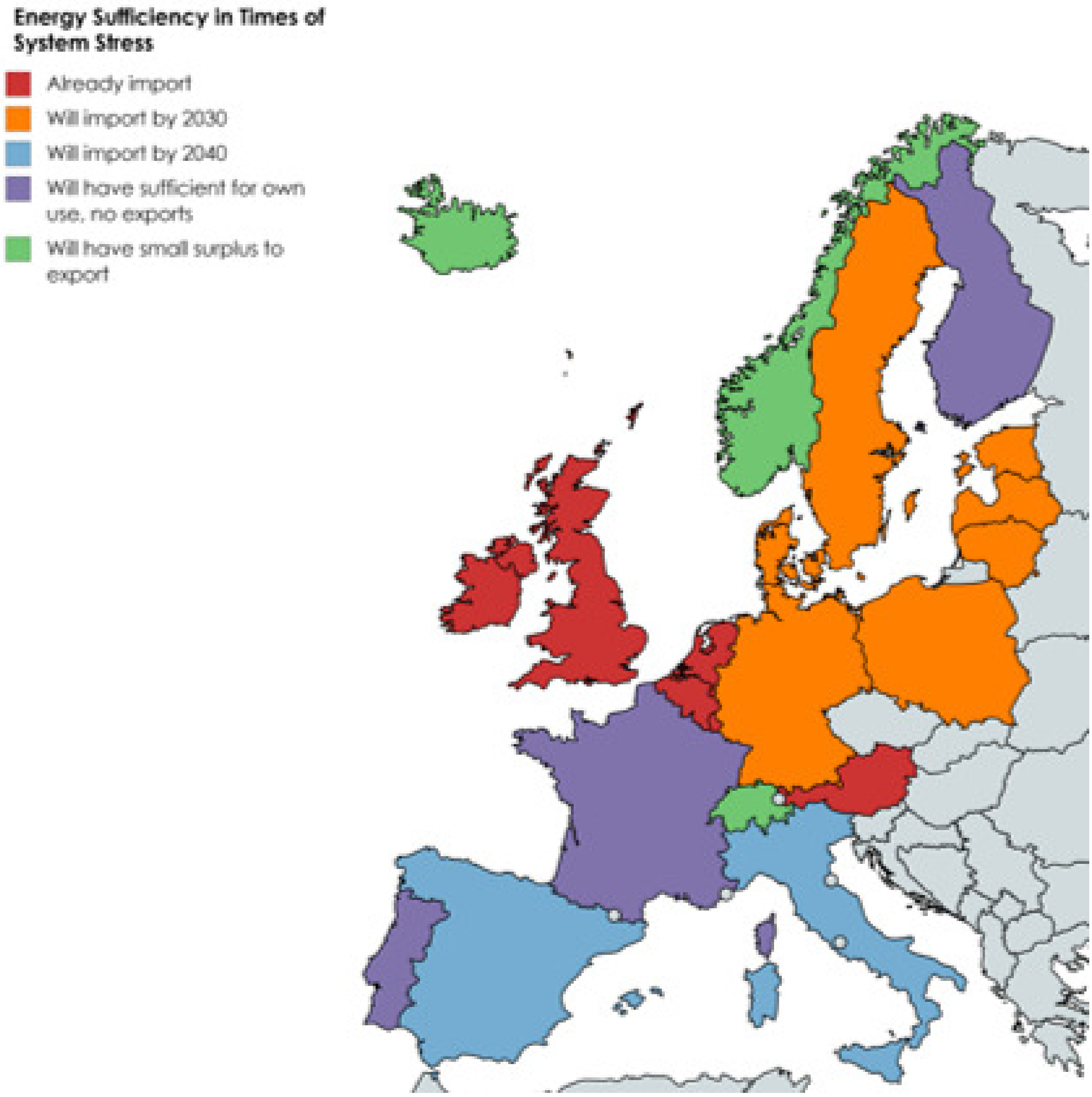
[33] P66, Interconnectors



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 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.

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.
- If an earlier stage innovation would create a technology useful to the SO, then a less binding MoU 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.

System Operators should be able 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, 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 connections retain their 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.

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 E: Regulatory Definition of Storage

What Is Storage?

Storage stores electricity. It does not generate new electricity (except for traditional CAES, see next paragraph): it only re-sells the electricity (minus losses) that it purchased. It is therefore not generation. It moves electricity in time, much as interconnectors move it in location.

Traditional CAES alone is a mix of generation and storage, because it burns fuel to re-heat the air. It can be treated partly as storage and partly as generation, in proportion to the percentage of the output energy that derives from the fuel. Adiabatic CAES does not have this issue: it is pure storage.

Triple Charging

There is a general mis-perception that storage is double-charged for grid access charges: paying for consumption and again for generation. It does, but also the electricity purchased has also already paid charges, so storage is actually triple-charged.

Interconnectors do not pay for grid access, though the electricity they carry has already had grid access charges paid. This is correct: they are merely an extension of the grid, providing grid services. The same is true of storage: it merely provides grid services and therefore should not be charged for grid access.

How the Decision Was Made

Naturally the incumbent generators want to keep it this way, to keep the playing-field tilted sharply in their favour. Storage companies want "zero charging" (i.e. reduce to charging only for the purchased electricity) on the grounds that storage doesn't generate. So Ofgem decided to split the difference and define storage as generation.

They stated that this was a partial solution, adopted because it didn't need primary legislation; when the opportunity for primary legislation would occur, then they would seek to create a true definition of storage[34]. However now they are proposing to

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

- "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".

define storage in primary legislation, which defeats the purpose of the interim solution and prevents a correct definition.

They now say that they wish to define it as storage because they can base the definition on existing regulatory categories. But that would be the case equally if they based the definition of storage on that of interconnectors – and with fewer modifications needed.

I am told that the industry is happy with the current proposal. Given that the industry is dominated by incumbent generators, that does not surprise me. However the need for change was also identified by the National Infrastructure Commission[35].

Problems with Defining Storage as Generation

There are many problems with defining storage as generation, which can be summarised as:

1. Charging
2. Grid Code Requirements
3. Grid Operator Constraints
4. Grid Connection Costs
5. Contractual
6. HM Treasury
7. Sundry Regulations

1. Charging

As cited at the beginning of this document, storage is triple-charged for grid access; the proposal is to move it to double-charged. This keeps the playing-field tilted in favour of generation and interconnectors, which are both single-charged – generation as generation and interconnectors within the price of electricity purchased. This therefore subsidises generation at the cost of the bill-payer. It provides even more subsidies to foreign generation and of the UK bill-payer, as grid connection charges for generation are lower on the continent than in the UK and the

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- "Our aim: a level playing field for DSR and storage competing with other forms of flexibility and more traditional solutions."

[35] 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."

UK does not charge differential fees (i.e. the difference). It is the bill-payer who loses out most because it disadvantages the most cost-effective means of balancing the grid.

2. Grid Code Requirements

The grid code for generation is loaded with requirements that are suitable for generation (e.g. 15% over-generation capability) but unsuitable for storage. This is right and proper owing to the nature of the generation asset being regulated – but therefore not right or proper for storage. The code for interconnectors does not have most of these, and therefore is much more suitable for storage.

Ofgem says that the grid code is determined by the industry, and therefore the grid code consequences of the regulatory mis-definition of storage are not their responsibility. But this overlooks that (a) the grid code is built on the regulatory definitions and reflects them, and (b) those with the greatest input into grid code matters are the large incumbent generators who have sufficient resources and who also have little interest in storage in comparison with their interest in generation.

3. Grid Operator Constraints

Both transmission and distribution operators are banned from owning generation, with a derogation of up to 6MW for DNOs. Yet both see huge potential benefits from storage, in balancing the grid, in providing stabilisation services, and in alleviating constraints and deferring capital investment. Both would invest in storage if permitted. And both would wish to support storage with NIC / NIA funding, which they are not permitted to do while storage is defined as generation.

Defining storage as storage would enable this. But it would also give the flexibility of allowing, disallowing and/or constraining such ownership and/or operation, as regulations (rather than primary legislation) can be used to do so – if storage is defined as storage rather than as generation.

And the ability to invest NIA / NIC funds in storage and in the issues relating to it (e.g. developing a standard system for calculating its effects on grid capacity, such as alleviating congestion like the Leighton Buzzard and Orkney plants) would greatly assist the network to adjust to a zero-carbon future.

4. Grid Connection Costs

Currently the effects of a proposed plant on grid loads is to calculate its operation as consumption, and again to calculate it as generation. This maximises the cost and lead time of grid connections, thereby making storage much more expensive and severely constraining the locations in which it can cost-effectively be built.

Storage mostly acts counter-cyclically, alleviating rather than creating grid congestion. It is on this basis that the batteries in Leighton Buzzard, Orkney and Eigha were proposed. Therefore grid connection requirements should be calculated based on storage being storage, not on it being generation and/or consumption.

Doing so would reduce connection costs and lead times, consequently increasing its roll-out and reducing consumer costs.

Likewise, operational grid access charges would need their own computation to encourage storage to alleviate grid challenges, and thereby speed roll-out and reduce consumers' bills.

Creating such models would be ideal subjects for NIA / NIC projects. There may be a conclusion whereby different constraints in operating modes of storage would incur different connection construction costs and ongoing charges.

5. Contractual

National Grid is unable to enter into a contract for "storage services" which cuts across many current and proposed contract types, because storage is not legally defined as such. This means that storage has to bid for a huge revenue stack of separate services, every 2 years or less, with many adverse consequences, including:

- The TSO / DSO has huge administrative and grid control burdens as they can't just ask the storage to respond to a situation – they have to select from a vast menu of situations and responses before triggering each one individually.
- We are eligible for a stack of 12 contracts, with another 4-6 being mooted at present. This means that we have to administer 12-18 contracts concurrently, ensuring correct compliance, invoicing and contract management for each, adding enormously to our administrative costs which we would have to reflect in our prices, which ultimately will cost the consumer a lot.
- Each of these revenue streams needs to be re-bid every 6-24 months, with consequent administrative burden on both us and the TSO / DSO, again adding to consumer costs.
- Each of these bids has a chance of failing to win a contract, meaning that –
    - We have to price in the possibility of failure, having to operate for a period without a contract or having to fill that "slot" with a lesser-paying contract;
    - We also have to price in the additional administrative costs of having to bid for more contracts than we win;
    - Our financing costs will be higher owing to the commercial risk;
    - And all these costs will ultimately be passed on to the consumer.

With a regulatory definition of storage as storage, the TSO / DSO would be able to let contracts for "storage services", maybe split into primary and secondary to reflect different storage types and characteristics – PHES and CAES as primary and batteries / DSR as secondary, with flow batteries maybe being able to choose.

6. HM Treasury

The Treasury offers certain incentives for investment, such as the Enterprise Investment Scheme (EIS), which explicitly list generation as ineligible. The Treasury uses the regulatory definition of storage (currently generation plus consumption) as its own definition. Therefore defining storage as generation will greatly reduce investment into storage, and increase the returns that investors require for doing so, and thereby increase the cost of de-carbonising the grid.

7. Sundry Regulations

Other regulations, such as planning regulations, also base some of their rules on whether or not a plant is or will be generation. Mis-defining storage as generation would continue to ensure that storage is judged by characteristics that it does not possess, often to its (and thus the grid's and consequently the consumer's) disadvantage.

Proposal

Define storage, in primary legislation, as storage.

Base the definition on that of interconnectors.

The grid code would therefore be modified, based on interconnectors rather than trying to fit a round storage peg into a square generation hole.

Enable contracts for "storage services" to be let by the TSO and DSOs.

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: About Storelectric and the Author

About Storelectric

Storelectric (www.storelectric.com) is developing truly grid-scale energy storage using an innovative form of Compressed Air Energy Storage (CAES). This uses existing, off-the-shelf equipment to create installations of 500MW, 2-21GWh with zero or low emissions, operating at 68-70% round trip efficiency, at a cost of £350m (€500m) (estimated for 3rd – 5th plant), and a levelised cost cheaper than that of gas-fired peaking plants (OCGT). Capex is one-third that of pumped hydro per MW and 1/75th per MWh; similar to 10-year target prices of batteries per MW and less than 1/1,000th per MWh. There is potential in the UK to store the entire continent's energy requirements for over a week; potential in mainland Europe and the USA is greater still, with global roll-out planned.

The next stage is to build a 40MW, 200MWh pilot plant with over 62% efficiency (grid-to-grid), using scale versions of the same technology, for which Storelectric is currently raising funds. Construction will take 2-3 years from funding, and the first full-scale plant a further 3-4 years. The consortium includes global multinationals who cover all the technologies involved, their installation, financial and legal aspects.

Storelectric has a second technology, CCGT CAES, which is the only CAES technology that is retro-fittable to a suitably located gas-fired power station (either CCGT or OCGT). As such it is a very good value technology that can almost halve emissions and add storage-related revenue streams, giving new life to stranded assets. It is an excellent transitional technology.

In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES.

About the Author

Mark Howitt is a founding director of Storelectric. He leads Storelectric's technical and operations, minimising technological risk, maximising efficiency and environmental friendliness, and speed to market. 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 his technology, 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.