Mark's Blog

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Review of Electricity Market Arrangements (REMA) Response to Briefing Document

The British Government's consultation "Review of Electricity Market Arrangements (REMA)[1] is an excellent initiative, recognising that current market arrangements will not deliver Net Zero affordably, reliably and resiliently, and reviewing how these arrangements need changing to do so. Therefore this initiative has my total support, which should be borne in mind even when my response may appear to be quite critical.

This response is not only the text below, but also the documents in the references which (especially those on the Storelectric website) further explain and amplify the relevant points.

Remit Too Narrow and Short

The Rise in Energy Prices

The consultation's Executive Summary ascribes "the recent rise in energy prices" to "volatile international energy markets. Yes, Ukraine-related energy supply issues have created a spike and volatility in energy prices, but consumers were complaining long before Russia invaded Ukraine on 24th February. The more enduring reasons are:

- ♦ Rising capital costs of the grid, on which large-scale, long-duration, naturally inertial storage of suitable location and scale (both size and duration) can save billions[2];
- ♦ Rising operational costs due to the challenges of the energy transition[3];
- ♦ Dependence on imports through interconnectors[4] rather than on having sufficient storage to deliver security of supply;
- ♦ An inability to contract and incentivise projects that benefit both network and operation of the grid[5]; and
- ♦ A dreadful regulatory and contracting environment[6].

Unless and until these challenges are addressed, whole-system costs will continue to rise exponentially and will ultimately be totally unable to deliver Net Zero affordably, reliably and resiliently.

[1] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
[2] https://www.storelectric.com/saving-billions-on-grid-upgrades/
[3] https://www.storelectric.com/challenges-of-the-electricity-transition/
[4] https://www.storelectric.com/interconnectors-and-imports/
[5] https://www.storelectric.com/offshore-energy-networks/
[6] https://www.storelectric.com/where-grid-regulation-went-wrong/

Too Narrow and Technocratic

Most of the questions in this consultation are too narrow and technocratic: what's being missed is the big picture, and therefore integrated solutions at a scale suited to the scale and breadth of the challenge. In particular, it considers grid operation and contracting, not the network itself – and it's that interface between the network and its operation that is crucial to the greatest benefits.

Myopic Vision

Moreover, the vision of the consultation is too myopic: solutions targeting 2035 commitments will require substantial re-work, un-doing and replacement to achieve 2050 commitments, whereas targeting 2050 will achieve 2035 along the way and, overall, would be much more achievable, affordable, reliable and resilient. This short-sightedness of addressing the near-term targets and "low-hanging fruit" while putting the medium- and long-term targets and the more challenging actions on hold is precisely what has led us to this situation, in which the system is costing exponentially more to run each year, has numerous near-misses annually for widespread blackouts, and has flat-lined in its carbon intensity[7].

If we invest in plant, infrastructure and equipment that is suited to 2030 or 2040 objectives, then it will become stranded assets well before the end of their economic life as emissions targets drop. Moreover, they will guarantee that we miss those targets because of legacy assets that exceed them: only by building new assets that greatly improve on such targets can we balance legacy assets to achieve the targets.

Wrong Questions Throughout

Throughout this report, the wrong questions are asked. Each time it asks: do we agree with the vision or objectives? Yes, but the rest of it – what is proposed in order to achieve such vision or objectives – is not fit for purpose.

Chapter 1. Context, vision, and objectives for electricity market design

Context and Vision

Q1: I agree with the overall vision but not with the means outlined for achieving it: it's too narrow and short term in outlook.

- ♦ Narrow: it ignores need to integrate electricity generation and flexibility with (a) the non-energy parts of the electricity transition, such as stability, reliability and resilience; (b) grid infrastructure and constraints; (c) renewable generation; (d) demand such as electrolysis and fuel synthesis.

[7] For carbon intensity flat-lining, see p5 of https://www.storelectric.com/wp-content/uploads/2022/07/Analysis-of-National-Grid-Future-Energy-Scenarios-2022.pdf

- ♦ Short term: the only way to achieve 2030, 2040 and 2050 objectives cost-effectively is to gear all changes and investments to be 2050-compatible, as otherwise legacy plant and infrastructure will ensure that those objectives are missed, and investments would become stranded assets within a fraction of their economic life.
- ♦ The following provides further details.

Consumers

The "*huge support package to shield consumers from the worst impacts of volatile international energy markets this winter*" that the government has provided is a mix of good and bad. The good is the assistance that does not reduce the incentives to make the changes necessary for Net Zero (i.e. direct support to consumers, especially the poorer ones), and the bad are the measures that reduce energy prices regardless of environmental friendliness. Thus,

- ♦ Granting a fuel allowance to recipients of state aid, a rates rebate for others, and help to those who need high energy costs (e.g. the elderly who need heating, the sick who need medical equipment operating for much or all of the time) is good: those who reduce energy consumption would benefit from doing so;
- ♦ Capping energy bills is bad: above the cap there is no incentive to reduce energy consumption or fit insulation, renewable generation, storage etc. while giving comfort that a high-emissions lifestyle will never become unaffordable;

An across-the-board windfall tax on energy companies is bad: it gives no incentive to clean up their energy – instead, it should be a windfall tax on the emissions of the energy companies.

Additionally, using energy companies to deliver state aid or to provide benefits for some and not for others is bad: it confuses political with regulatory measures[8] to the detriment of the entire industry and, ultimately, consumers.

Therefore, many of the cost-control measures taken by the government run directly counter to the "*essential*" objective of "*decarbonising the power system [and] meeting ambitious GB carbon targets*".

Contracts for Difference (CfDs)

The Review correctly applauds the CfD scheme for encouraging renewable generation, while missing the fact that, while it was originally necessary to help the technologies through the costs of early implementation, (a) it remains necessary only because of gross failings in the regulatory and contracting system and (b) the lack of equivalent scheme for large-scale long-duration naturally-inertial electricity storage is why such has not been built, and why whole-system costs are escalating exponentially.

[8] https://www.storelectric.com/political-or-regulatory/

Carbon Price, and Emissions Added Tax

Again, Carbon Price Support is excellent as far as it goes, which is not far enough, but is prevented from going further by politics and by poor design:

- Poor design, because there is no crediting of carbon price for exports to lower-charging countries and no charging of the support price for imports from such countries, thereby disadvantaging British industry vis-à-vis other countries;
- A political football, as it is capped and reduced to compensate for high energy prices and so as to avoid further disadvantaging British industry – see good and bad measures, above.

Much better would be an Emissions Added Tax[9] that taxes the emissions created by each business while avoiding taxing their inputs; it can more easily be (part-)credited on export and (part-)charged on import, just like Value-Added Tax.

Emissions Performance Standards

Standards for emissions performance are excellent, but not implemented broadly enough to achieve their full potential. They should be applied to contracts, so that (a) threshold standards must be achieved in order to bid and (b) remuneration or other commercial leverage (e.g. contract length, position in the Merit Order for dispatch) is affected by the cleanliness or otherwise of the plant.

Vision for Future Market Arrangements

The vision is correct, but neither the current nor the proposed means will achieve it[10].

- Renewables cannot be deployed cost-effectively if there is no cost-effective and easily manageable way to procure and operate the balancing, ancillary, stability, reactive power/load, power quality, Black Start and other services that are needed to supplement the intermittent, asynchronous generation.
- Flexibility is worth little without duration, yet that is how it is planned and purchased.
- Many of the flexibility technologies cited will never deliver what is needed or, if they do, they will deliver it partially and/or excessively expensively and inefficiently.
- Some aims are conflicting, e.g. relying on price volatility to incentivise large-scale storage, then maximising DSR and batteries to minimise price volatility.
- Consumers have minimal incentive "to take greater control of their electricity use": it can only work if automatic, remote and almost intervention-free – and even then the incentive is slight.
- Encouraging distributed generation beyond a certain point (to be modelled and calculated) merely adds to system costs while reducing system resilience because nearly all distributed systems rely on the grid for back-up, so the grid needs enough to provide that back-up; distributed resources above that threshold merely cannibalise the revenue streams of the transmission-

[9] https://www.storelectric.com/incentivising-clean-energy/
[10] These topics are discussed at various points within https://www.storelectric.com/wp-content/uploads/2022/07/Analysis-of-National-Grid-Future-Energy-Scenarios-2022.pdf

connected plant, requiring the latter either to close (or not be built) or to raise their prices to provide an economic business model. Thus the "substantial savings" observed narrowly become substantial additional costs when observed broadly: the current system is riven with such trade-offs.

- Digitalisation and DSR merely optimise the energy that is present, over limited periods of time; if there isn't enough energy, no amount of these can provide enough to keep the lights on.
- The digitalisation will not "send the right price signals to co-ordinate investment" – it will only provide operational signals, and actually discourage investment by removing the market's price signals.

Investment in the Network

It is true that "we also need to see significant investment in new network capacity to transport all this low carbon electricity from generators to consumers", though this is severely under-appreciated. Many forecasters (e.g. Breakthrough Energy[11], McKinsey[12]) point out that the grid needs to more than triple in size, unaffordably even for America (so what hope have we?) unless projects that tackle both hardware and operation of the grid are suitably incentivised[13].

REMA Objectives

Q2: The objectives (in the box) are laudable, but the proposal will not even come close to achieving them. It is true that they "*can only be delivered jointly with Ofgem*", but it is the government's responsibility to determine the regulatory framework in which they operate, and the current one is very far from being fit for purpose. Nor does Ofgem show any inclination to undertake the kinds of reforms necessary to make it fit. The following provides further details.

Security of Supply

The way outlined to deliver security of supply is to:

- Ensure that renewables are connected to the grid through suitably sized large-scale long-duration naturally inertial storage, which will save billions in grid reinforcement[14]; and
- Build enough storage to run the country without use of interconnectors[15], only zero-carbon generation within the country[16].

Gas has no place in the energy mix: CCS and CCUS[17] are greatly exaggerated in their capabilities and costs, no account is taken of the 35-45% inefficiency that such

[11] https://www.breakthroughenergy.org/scaling-innovation/modeling-the-grid
[12] https://www.mckinsey.com/business-functions/operations/our-insights/global-infrastructure-initiative/voices/upgrade-the-grid-speed-is-of-the-essence-in-the-energy-transition
[13] https://www.storelectric.com/saving-billions-on-grid-upgrades/
[14] https://www.storelectric.com/saving-billions-on-grid-upgrades/, cited previously
[15] https://www.storelectric.com/interconnectors-and-imports/
[16] https://www.storelectric.com/calculating-the-need-for-storage/
[17] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/

equipment imposes on the parent power station, and the risks and costs of CO_2 storage are ignored by advocates of it. And to keep any such power stations in reserve for occasional use *in extremis* would cost a fortune in reserve-type contracts that don't exist and aren't planned, because their utilisation would be negligible; likewise, they would require an entire gas grid to be maintained and stocks retained for very rare use, also financed by reserve-type contracts – and all such facilities would need ongoing maintenance and periodic operation to ensure that they work when needed. For this last reason, keeping unabated fossil fuelled power stations in reserve is also prohibitively expensive and wasteful.

Cost-effectiveness

The entire approach to cost-effectiveness needs to be changed.

- Short term contracts cost more over the medium and longer terms and fail to provide for the renewal of the asset base; long term contracts are cheaper in the long run as well as providing for such renewal[18];
- Salami-sliced contracts make large and highly capable plants almost impossible to finance, build and contract profitably because their revenue stacks are complex and many revenue streams cannot be delivered without delivering other services for which contracts may not have been won – and, to hedge for such eventualities, contract bid prices must be inflated[19];
- Therefore the costs of the energy transition are high and rising exponentially, and are likely eventually to hit a ceiling of impossibility[20].

Locational Signals

Providing locational signals are good, up to a point. Beyond that point they sub-divide today/s 50GW market (and tomorrow/s 80-150GW market) into a myriad little sub-markets, rather like supplying consumers with only family-owned corner shops and no supermarkets: it reduces choice and resilience in the supply chain while greatly inflating costs.

Locational signals also need to be flexible: many needs identified at one location may be addressed by solutions at an entirely different location. Just as the Dounreay power station on the Scottish north coast required grid reinforcement right down to Leighton Buzzard in Hertfordshire, so also intermittency or changing demand can lead to congestion far away. Consider an offshore wind farm: its intermittency means that the entire grid must be sized for peak generation, including overcoming constraints tens or even hundreds of miles away; but by adding storage between the wind farm and the grid, that intermittency can be eliminated at source, avoiding such distant reinforcement.

[18] https://www.storelectric.com/wp-content/uploads/2021/03/Issues-with-Ever-Shortening-Contract-Durations.pdf
[19] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf
[20] https://www.storelectric.com/challenges-of-the-electricity-transition/

REMA Scope

Inadequate Scope

As written above, the scope is too narrow. It excludes, for example:

1. Integration of non-retail electricity-related markets, e.g. combined contracts for energy and inertia, necessary for inertial plant;
   - ♦ Linked contracts may well, in total, be much cheaper for the consumer than current salami-sliced contracts, but this can never be explored or contracted under either current arrangements or the proposals of REMA;
2. Integration of complex developments, e.g. renewable generation (and maybe electrolysis and fuel synthesis) with electricity storage without going through substations between each plant;
3. Infrastructure, e.g. where a plant both benefits grid operation and saves on grid reinforcement, it cannot benefit from contracts with both System Operator and Transmission Operator;
   - ♦ Nor can such projects demand the active involvement / support of the Transmission Operator, whose incentives in this regard are perverse, so NGET determinedly refuses to support or even consider/analyse them (which may also apply to other transmission and distribution operators too);
4. Duration of scope and contract, which will usually deliver greater cost-effectiveness over the medium and longer terms;
5. Incentivisation and construction of commercial first-of-a-kind plants should be in scope, as they are what is needed NOW (owing to construction and roll-out lead times) in order to achieve 2035-2050 emissions targets affordably, reliably and resiliently;
6. There is no consideration of the fact that the price of each MWh of electricity is the same regardless of its value:
   - ♦ Dispatchable and baseload generation is worth more than intermittent, as the latter requires grid reinforcement, curtailment and the procurement (and connection) of balancing services, whereas the first two do not,
   - ♦ Synchronous generation is worth more than asynchronous, as the latter requires additional sourcing (and connection) of stability, reliability, resilience and power quality capabilities, whereas the former does not,
   - ♦ Low and zero emission electricity is worth more than high emission electricity, by the amount of the societal cost of carbon (£450-696 per tonne of CO_2 equivalent[21] – see below)
   - ♦ Large scale is worth more than small, as the latter requires ever increasingly complex contracting, management, settlement, validation, approvals and control room activities as compared with the former,
   - ♦ Higher-voltage generation is often (not always) worth more than lower-voltage, as all distributed systems rely on the grid for back-up during times of system stress, so the grid needs to have enough to provide back-up – and having excess on lower-voltage networks would merely cannibalise its

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21 https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

revenue streams without removing the need for such higher-voltage capability, thereby increasing overall system costs;

7. Interconnectors (if not their existing contractual arrangements) should be in scope because the current reliance on them will guarantee widespread and frequent black-outs during times of system stress that are concurrent with those of our neighbours (as they often are), because our neighbours' plans are also relying on imports during such periods[22] – the reversal of interconnector flows, requiring us to put coal-fired power stations back into regular operation, during the Ukraine crisis proved that, and current forecasts are for 10-hour Loss of Load Expectation next winter[23].

Interactions Between Reforms to Electricity and Retail Markets

The interactions between reforms to electricity and retail markets are all good, but omit the interactions that have the greatest effects on overall system affordability, reliability and resilience, such as those between:

- Short, medium and long terms;
- Market design and the types of plant and development that they remunerate and penalise;
- Contracts, services and infrastructure requirements;
- Regulations, contract types and capabilities built on the grid;
- Distribution-connected and transmission-connected plant;
- Grid energy, stability, reliability, resilience, power quality and Black Start;
- Plant capability, regulatory and contractual structure, and overall system cost;
- Prices for individual services and overall system cost;
- Quick fixes, short lead time contracts and long lead time solutions.

Because of this lack of understanding (or admission) of these interactions, over the past decades (and still ongoing), actions in relation to the energy system have mostly been short-termist, narrowly-focused, and aimed at getting the best result for a single issue even at the cost of making the whole system costlier and harder to manage (and less reliable and resilient). The voices (like mine) that have warned of future hazards (such as exponentially increasing non-energy costs, tripling grid size, lack of investment in broadly capable or large-scale solutions, unreliability of imports for actual system needs and so on, every one of which has been proved by events in the last three years) have been ignored until those hazards materialised – and then the hazards have been addressed in urgent, quick-fix, piecemeal manner that just builds even worse problems for later.

Retail initiatives have little effect on system needs and costs. FES 2015 published an assessment that peak DSR potential is 5% of peak demand. As the same resource cannot be used multiple times during an evening peak, and as most DSR is only suitable for short-duration actions, that reduces peak DSR potential to 1-2% of peak demand. And that assumes 100% take-up: given that maximum savings advertised for

[22] https://www.storelectric.com/interconnectors-and-imports/, cited previously
[23] https://www.current-news.co.uk/news/current-price-watch-low-import-available-could-lead-to-10hr-lole-over-winter

the Smart Meter roll-out were 0.5% of energy bills, then the incentive for widespread uptake is minimal. Smart Charging and Vehicle-to-Grid capability can greatly increase this – but to nowhere near the amounts envisaged by planners[24].

Wider Policy Considerations

The document is correct that "*there are a wide range of policy areas which are beyond the scope of REMA, but which will be critical enablers of our reforms*". Examples (much more, broader and more fundamental than those outlined in the document) are above. However they should be included within the scope of this Review so as to ensure that the reforms undertaken show a joined-up approach that will stand the test of time.

The continual focus on "*energy bills*" is, in itself, very blinkering and short-termist as it focuses on what will affect retail payments today and in the near future, rather than whole system costs in the short, medium and long terms. Therefore this focus on "energy bills" is therefore the direct cause (as it has been ever since privatisation) of those energy bills rising inexorably to unaffordability. Such a focus on energy cost is the reason, for example, that the cost of electricity has dropped from 75-80% of electricity prices to 20-25%, the rest being whole-system costs, charges and levies[25].

Emissions are indeed covered by the UK Emissions Trading System, but that levies nothing like the true societal cost of emissions which is £450 – £696 per tonne of CO_2 equivalent[26], compared with prices at the beginning of August 2022 of €80 (£67) in the EU to buy carbon credits equivalent to 1 tonne of CO_2 equivalent. The UK Carbon Price Support is set at £18 above the European ETS price, bringing the UK ETS price up to a mere £85. This difference between societal cost and price of emissions is an enormous (£365 – £611 per tonne) implicit subsidy for fossil fuelled technologies. This could be avoided, without penalising British industry vis-à-vis the rest of the world, by an Emissions Added Tax system operated like Value Added Tax[27].

Indeed, the headline high cost of nuclear is a prime example of market failure due to current market arrangements. If the electricity price were to reimburse the value of baseload/dispatchability, synchronicity and low/zero emissions, then nuclear would appear to be very good value for money.

The Case for Change

Current Electricity Market Arrangements

As outlined above, current electricity market arrangements are exceedingly short-termist, blinkered and self-defeating, resulting in a grid that is increasingly

[24] https://www.storelectric.com/vehicle-to-grid-and-shared-mobility/
[25] https://www.storelectric.com/challenges-of-the-electricity-transition/, cited previously.
[26] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal, cited previously
[27] https://www.storelectric.com/incentivising-clean-energy/, cited previously

unaffordable, unreliable and fragile. Indeed, the RIIO structure of market reviews itself exacerbates the problem, imposing a North Korean 5-year view on the markets after which everything is re-set – and recently the problem has deteriorated with the imposition of mid-RIIO reviews and changes. No planning can take place beyond that fixed 5-year window; if 3 years through the RIIO period, then the window is only 2 years, scarcely enough to develop a business case and feasibility study, let alone the pre-construction FEED (Front End Engineering Design), planning, environmental surveys and actions, public consultations, grid connection applications and negotiation, contracting, construction, commissioning and recovery of costs from operating an infrastructure-scale project. Unless there is sure visibility over such timescales, such projects will not be implemented.

That is why almost every large-scale project has been done under a special financial instrument (e.g. ROCs, OFTOs, CATOs, CfDs, RAB, cap-and-floor) that provide 15-20 year certainty for a clear majority of the development's potential revenues. And this is also why the T-4 Capacity Market has failed dismally to incentivise such developments:

- While it has a 15-year potential view, bids are welcomed for much shorter timescales (typically, 85% of contracts are for one year, turning it into merely a second bite of the T-1 cherry);
- Lead times to contract delivery are too short even to build a new transmission grid connection;
- The value of the contract is worth as little as 5-10% of the revenue stack of most complex / highly capable plant and projects, meaning that 90-95% of revenues are from short-duration contracts or spot trading, so financiers still treat it as a purely merchant plant.

What the Current Market Has Delivered

The document presents a Panglossian view of what EMR has delivered. It was not EMR that delivered:

- The 27GW of low-carbon capacity, it was R0Cs, CfDs and other financial inducements, which also created the volumes that enabled the cost of offshore wind to drop by 70%;
- The Capacity Market, which was a partial and inadequate response to the failings of EMR;
- Adequate capacity margins (security of supply), which would be negative if the ESO were to take a more clear-headed view of winter margins –
    - ◊ In the 2022 Winter Outlook Report preview the entire supply margin is from interconnectors, on which we cannot rely[28] – and some of the actual demand will be met by renewables, which will all periodically be generating nothing (after sunset on a windless day),
    - ◊ In the current energy crisis, our interconnector imports have already turned negative and we've had to turn on coal-fired power stations, whose output is included in the supply figures in this report.

[28] https://www.storelectric.com/interconnectors-and-imports/, cited previously

A clearer-headed review of the electricity system since EMR shows that, as compared with other European systems, the UK has dropped:

- From the continent's second cheapest electricity system to one of its most expensive;
- From the most reliable to one averaging black-outs or near misses more frequently than every couple of months;
- From one of the most self-sufficient to one depending on imports through interconnectors for actual demand as well as supply margins, and current forecasts are for 10-hour Loss of Load Expectation next winter[29];
- From one with a self-sustaining asset base to one whose asset base ages almost a year every year and capacity is reducing as plants get so old as no longer to be maintainable;
- From having dispatchable and baseload generation sufficient for generous capacity margins to one relying on wind, sun or interconnectors at all times – and all of these are uncertain and guaranteed regularly to fail concurrently.

One of the objectives of EMR was for markets to set energy prices; as we have seen, the cost of energy is now only 20-25% of electricity prices, and falling.

It's not EMR itself that has been such a disaster, it's the regulatory and contractual structures that have caused the problems, as analysed elsewhere[30].

Future Challenges

It is true that decarbonising the power sector "*can be done with technologies that are known today*"; however it cannot be achieved by merely tweaking existing market arrangements. These need a radical overhaul, but one which can be implemented gradually and without enormous market disruption – and, crucially, without subsidy[31].

The models used to identify the future challenges are all dispatch models. Such models operate well over a period up to 2-5 years hence; thereafter their mass of assumptions and estimates build on each other to become a highly unreliable predictor of the future. This is why Future Energy Scenarios is such a poor plan[32].

Nonetheless, there is significant merit in the five key challenges identified:

1. The pace and breadth of investment in generation capacity does indeed need to increase greatly – though by more than FES predicts;
2. System flexibility does indeed need to be increased, but needs much broader considerations –

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[29] https://www.current-news.co.uk/news/current-price-watch-low-import-available-could-lead-to-10hr-lole-over-winter, cited previously
[30] https://www.storelectric.com/where-grid-regulation-went-wrong/
[31] https://www.storelectric.com/a-21st-century-electricity-system/
[32] FES 2022 analysis: https://www.storelectric.com/wp-content/uploads/2022/07/Analysis-of-National-Grid-Future-Energy-Scenarios-2022.pdf; brief summary: https://www.storelectric.com/analysis-of-national-grid-future-energy-scenarios-2022-summary-of-findings/

- Flexibility without duration is meaningless – the flexibility needs sufficient duration to keep the lights on throughout a windless winter evening and overnight, when interconnectors will fail,
- Flexibility needs to be accompanied by system stability, reliability, resilience, power quality and Black Start if the system as a whole is to perform;

3. Locational signals are indeed good, but only up to a point – see above;
4. System operability can only be retained if flexibility includes all the aspects of system stability, reliability, resilience, power quality and Black Start;
5. Price volatility management is a totally erroneous objective: the volatility is there to provide market signals, so any dampening of those signals is counter-productive.

Those key challenges miss some very major challenges, such as:

6. Infrastructure costs: unless intermittent generation is connected to the grid THROUGH storage, the grid needs to more than triple in size;
7. System management costs: procuring ever smaller specks of services (minimum size for participation in markets is now below 1MW) with ever shorter contracts multiplies the cost and complexity of grid management, guaranteeing failures despite escalating costs, whereas connecting renewables through synchronous storage enables the renewables+storage to be managed as though they were a power station;
8. Correct objectives: increasingly symptoms (e.g. an amount of storage with ultra-fast response times) are targeted, instead of causes (e.g. system stability) – the grid of 2010 was much more stable without any sub-second response times than today's grid, because it had sufficient natural inertia, so defining the challenge as more sub-second response resource prevents the provision of natural inertia and thereby entrenches and exacerbates grid instability;
9. Overall system costs: by focusing on the best short-term price for every narrow sub-service, the total system cost is escalating exponentially (as described above);
10. Medium and long term affordability, reliability and resilience: it's the short-term focus that has led us to this current expensive, inadequate, unreliable and fragile grid and will continue to make it more so, which is why this REMA is so desperately needed, and why its remit needs to be longer term and broader.

Investment in Renewable Assets

The analysis of the cost structure for renewables is accurate, but should also be applied to large-scale long-duration electricity storage, which would lead to very different market arrangements for such storage as compared with today's. That is why, despite a decade of ever-increasingly urgent statements that more such storage is needed[33], none has been built in that time.

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[33] For example, the UK government's 2012 Technology Innovation Needs Assessment stated that the country needs up to 59.2GW new electricity storage with an average duration of 5 hours, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/593455/Electricity_Networks__Storage_ENS_TINA.pdf

Investment in Flexible Low Carbon Assets

This is rendered all the more important and urgent by the report's observation that "*Despite some variation across the country, many assets will be subject to similar weather conditions, and therefore will have similar output patterns*." This means that they will fail at the same time. And, because weather patterns of neighbouring countries are frequently similar, in future they will not have an exportable surplus for us to import, so the interconnectors will fail[34].

Why does this report (as other governmental and grid reports) always discuss flexibility without duration? It goes back to a 2012 report by Imperial College which stated "we should no longer talk about storage, but about ***flexibility and duration***", which they only partially understood, so ever since they have talked about flexibility without duration[35].

But throughout this report, system stability, reliability and resilience are ignored. Intermittent generation is asynchronous, so synchronicity needs procuring in the right places and quantities. And if the flexibility can deliver duration and synchronicity, then grid management and operation becomes very easy, affordable, reliable and resilient. Therefore electricity market arrangements should incentivise baseload/dispatchability, flexibility, duration, synchronicity and low/zero carbon, and especially in cross-cutting contracts where these services can be delivered in combination by diverse plants, as discussed above.

Short-Term Investment in Unabated Assets

Encouraging construction of more unabated assets is a fantastically irresponsible and self-defeating proposal.

Any unabated assets built now will take some years to complete. By 2035, when grid emissions are supposed to be zero, they will all be stranded assets, for the most part less than one-quarter of the way through their realistic operating life. Therefore addressing today's needs by building such assets is financially irresponsible. And if the government is seen to be encouraging such assets, then their remaining life will become a government liability.

Moreover, the emissions targets are hard enough to achieve with currently planned retirements of legacy assets on the system. Adding more unabated assets will guarantee that those targets will be missed, as well as creating huge political and economic lobby and incentives that will work against achieving a Net Zero grid.

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[34] https://www.storelectric.com/interconnectors-and-imports/, cited previously

[35] Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future, https://www.imperial.ac.uk/media/imperial-college/energy-futures-lab/research/Strategic-Assessment-of-the-Role-and-Value-of-Energy-Storage-in-the-UK.pdf – see the footnote on p 12: "*Resource adequacy requires several hours of storage duration, if peaking generation is to be displaced securely, based on the shape of the demand profile derived for 2030.*"

And CCS / CCUS for power generation assets is an exceedingly costly myth perpetrated by the fossil fuel industry[36]. Not only is it much worse than they claim (Boundary Dam was designed to capture 90% of emissions but only captures 33%) but it is much more expensive, imposes 35-45% inefficiency on the power station to which it is fitted (in Boundary Dam, 40%), and the costs and hazards of CO_2 transportation (50% heavier than chlorine gas, which was used as a weapon in the First World War, and less detectable and less protectable) and storage. Natural CO_2 eruptions have killed thousands in Lakes Nyos and Monoun[37] with potentially worse to come in Lake Kivu[38].

Increasing System Flexibility

"*The electricity system needs to match supply and demand on a second-by-second basis*." Correct, but it has to keep matching supply and demand for as long as it takes: hours, days, weeks, months… So flexibility without duration can only address a small subset of the challenges, and therefore contributes very little to the needs of the energy system as a whole. Load shifting (flexibility in when cars are charged and heat pumps are operated) can provide only a little relief at the edges of the system; it actually increases overall demand by the efficiency of storage. V2G consumes battery life and suffers currently-unresolved perverse financial incentives[39]. And load shifting using heat pumps will require substantial investment and space for thermal storage; domestic batteries require similar investment – noting the planet's very limited lithium, cobalt and rare-earth metal resources. The potential for battery vehicles is similarly constrained[40].

Forecasts such as "residual demand distribution", p31, are statistical averages. Electricity systems need to operate on worst case, where excess demand will exceed 100GW, or where there is excess demand for many hours or days. Unless the system is planned for the worst case, widespread and frequent black-outs are guaranteed. As interconnectors cannot be relied upon (see above), this means that we need enough storage to take us through these excess-demand periods, however long and frequent they may be: this amount of storage (both scale and duration) is easy and rigorous to calculate[41]. No amount of other "flexibility" can replace it because, for example, all load shifting needs to be delivered at some time within the longer excess-demand periods.

The document cites longer-term excess-demand and excess-supply periods. Currently there is no contract for reserve services. And there is little understanding of whether seasonal storage is actually the most cost-effective way forward: I believe that it is not, as sufficient hydrogen-fuelled power stations would have to be kept in reserve, seldom used and highly inefficient (whole cycle renewables – electrolysis – grid – storage – grid – power station – electricity again), sufficient to power the entire grid

[36] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/, cited previously
[37] https://www.smithsonianmag.com/science-nature/defusing-africas-killer-lakes-88765263/
[38] https://www.bbc.com/future/article/20201009-lake-kivu-the-african-lake-that-could-explode-with-methane
[39] https://www.storelectric.com/vehicle-to-grid-and-shared-mobility/, cited previously
[40] https://www.storelectric.com/electric-versus-fuel-cell-vehicles/
[41] https://www.storelectric.com/calculating-the-need-for-storage/, cited previously

other than what can be provided by other zero-carbon dispatchable or baseload generation. There is no mechanism to pay for that, either extant, planned or conceived. I believe that a ~25% excess of renewable generation, combined with sufficient storage of ~2.5 weeks' duration, would be much more cost-effective, especially if shorter-duration storage (both transmission and distribution connected) does not cannibalise its revenue streams. The alternative systems would have to be modelled.

The ramp rate issue (p32) would not be an issue if renewables were connected to the grid through suitably-sized and -specified storage. Network constraints and curtailment are also most cost-effectively addressed in this way, rather than by wholesale multiplication of the size of the grid[42]; the next most cost-effective way is by having sufficient stand-alone large-scale long-duration storage on the grid.

Maintaining System Operability

Stability, reliability and resilience need naturally inertial (synchronous) plants; any need that exceeds availability of synchronous zero-carbon generation should be addressed with synchronous storage. Using synchronous condensers and flywheels is a waste of money as they can only address synchronicity issues and none of the other challenges; synchronous storage can address most of the challenges concurrently and therefore much more cost-effectively if whole-system costs are analysed rather than narrow salami-sliced single-revenue-stream costs[43]. This applies to all matters such as inertia, reactive power/load, frequency response, voltage/frequency control, power quality (ignored in the document), phase-locked loops and similar aspects of operability.

Currently the focus for addressing all these operability concerns is sourcing plant with ultra-fast millisecond-scale response times. This is a highly costly fallacy: the pre-2010 grid carried more electricity and was cheaper, more reliable, more resilient and more easily operable because it had sufficient naturally-inertial plant on the grid. All these operability matters arise from a loss of natural inertia on the system; addressing them outside the context of natural inertia is perverse, costly and fraught with danger of multiple, frequent and widespread system failures. It is therefore excellent that, for the first time, stability is defined as "*primarily provided by inertia*", though frequency response, reactive power and restoration were historically also provided by inertial systems. Indeed restoration can only be provided by such plant, and can only be rolled down from higher voltages to lower rather than the other way round[44]. Synthetic inertia bears little resemblance to real inertia and does not deliver the same capabilities, hence the blackouts of 9th August 2019[45]. As gas-fired power stations with CCS are excessively costly, inefficient and polluting[46], the role must be taken by synchronous

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[42] https://www.storelectric.com/saving-billions-on-grid-upgrades/, cited previously
[43] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf, cited previously
[44] https://www.storelectric.com/wp-content/uploads/2020/09/Re-Starting-Net-Zero-Grids-Black-Start.pdf
[45] https://www.storelectric.com/wp-content/uploads/2020/02/Lessons-for-Europe-from-the-UK-blackouts-v2.pdf
[46] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/, cited previously

storage; synchronous condensers are, as discussed before, excessively costly in whole-system terms. (BECCS has other primary drivers of their business case, namely negative emissions.)

"*The move towards more distribution-level generation is also presenting operational challenges.*" True, but only the matter of increasing need for voltage control is discussed. Omitted is the fact that a certain amount of large-scale long-duration storage is required on the transmission grid to provide back-up in times of system stress. There will be an amount of distribution-level generation and storage that is beneficial but, above that amount (to be modelled), it eats into the revenue streams of the transmission-connected storage which must be there so must be paid for, so has to increase its prices for other services to compensate those lost revenue streams; therefore distribution-connected capability above that amount merely adds to overall system costs.

Managing Price Volatility

Price volatility has an economic purpose: to provide market signals to providers, encouraging them to make up for any shortfalls. This was identified by Ofgem on 15th May 2014[47] in their Electricity Balancing Significant Code Review decision to increase the limits of imbalance prices from £3,000 to £6,000, and reviewed by them approvingly on 2nd August 2018[48]. So why, over the last few years, has National Grid focused so strongly on eliminating price volatility by means of DSR and other anti-market mechanisms? It's lack of volatility that creates the bigger challenge to the system. It's volatility, among other things, that will pay for the storage needed to make the Net Zero system work without subsidy.

Of more use in ensuring sufficient capacity of the right types is providing sufficient long-duration contracts for them, especially for capacity, availability and reserve. Inasmuch as the grid needs to ensure sufficient stability services, these need to be long-duration contracts too – this focus on energy is totally distorting as it only addressing a fraction of the need. Non-energy grid operational costs last year were of the order of £4bn more than just 3 years before; grid infrastructure costs had increased by at least as much again[49]. The actions need to integrate and cover all of these.

And if new assets need to be built, they need long enough lead times to build the plant between winning the contract and delivering the service – yet not a single contract type has lead times that allow for a new transmission grid connection, let alone the planning and design involved in it, which could partly be addressed by reducing the lead times of grid connections and partly by flexing the lead time to be "grid connection plus X".

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47 https://www.ofgem.gov.uk/sites/default/files/docs/2014/05/electricity_balancing_significant_code_review_-_final_policy_decision.pdf

48 https://www.ofgem.gov.uk/sites/default/files/docs/2018/08/analysis_of_the_first_phase_of_the_electricity_balancing_significant_code_review_as_final_version_publication.pdf

49 https://www.storelectric.com/challenges-of-the-electricity-transition/, cited previously

When battery storage was needed urgently, EFR (Enhanced Frequency Response) contracts were developed which lasted for half the amortisation life of a battery. In response, sufficient batteries were built. The amortisation life of large-scale long-duration electricity storage plants is 30-60 years: to encourage those to be built, contracts are needed that cover at least half of that life, for a majority of their revenue stacks. This is not unprecedented: ROCs, CATOs, OFTOs, CfDs, RAB and cap-and-floor all provide such long-term contracts, and do so with sufficient notice to permit and build the plants following contract. Why long-duration synchronous storage was excluded from all of these is beyond comprehension, given that the need has been identified with increasing urgency for a decade (q.v.), without a single megawatt of it being built and BEIS / Ofgem / National Grid professing to be perplexed as to why[50]. The other reason is because such storage delivers such a broad range of capabilities that the revenue stack included in such an arrangement must include energy, ancillary and stability services – otherwise the hazards of salami slicing prevail[51]. A market structure that does this, as well as incentivising both decarbonisation and the introduction of new technologies, without a penny of subsidy, has been outlined before[52].

Moreover, if a mechanism such as cap-and-floor were to be introduced, it must have either an absent or a "soft cap", or there will be no further market incentive to continue delivering to the needs flagged by the markets, thereby undermining the markets. And such an absence of incentive will guarantee that no money is returned to Treasury / the system above the cap, as no further revenue-increasing actions will be taken. A "soft cap" provides that, above the cap, the profits are shared between the asset and "the system" / Treasury, e.g. ⅓ to "the system" and ⅔ to the asset: this will maximise both the effectiveness of the market in delivering system needs and the returns to "the system" / Treasury, while also maximising incentives for investment in such capability. The Renewable Energy Association analysed this and alternatives in some depth[53].

Separation from international commodity price fluctuations will only be achieved by having sufficient domestic generation (excluding coal and gas, whether abated or not – and abatement is too costly, inefficient and hazardous[54]) and long-duration storage. There is no other means, if subsidies are to be avoided. Ukraine proved that interconnectors cannot be relied upon[55]: as soon as continental generation proved insufficient for their own needs, interconnector flows turned negative and we had to not only turn on mothballed coal-fired power stations but also enter into 3-year contracts to keep them on.

50 https://www.storelectric.com/wp-content/uploads/2021/03/Issues-with-Ever-Shortening-Contract-Durations.pdf, cited previously
51 https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf, cited previously
52 https://www.storelectric.com/a-21st-century-electricity-system/, cited previously
53 https://www.r-e-a.net/resources/rea-longer-duration-energy-storage-report/
54 https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/, cited previously
55 https://www.storelectric.com/interconnectors-and-imports/, cited previously

Assessment of Future Market Arrangements

Question 3: the future challenges identified for the electricity system are a small fraction of the total such challenges, and addressed in piecemeal and myopic fashion, see below.

Question 4, I agree wholeheartedly "*that current market arrangements are not fit for purpose for delivering our 2035 objectives*", but disagree with the "*assessment of current market arrangements*" which are grossly deficient in scope, scale and timescale; see below.

Decarbonisation

Decarbonisation can only be incentivised when it is incentivised. Currently there is very little such incentivisation, with the carbon price being less than 1/10th of the social cost of carbon. This needs to be increased dramatically, with at least some of the proceeds going to the poor to compensate the extra costs – but not as an energy price reduction or their incentives to reduce / improve consumption are eliminated. Best of all would be an Emissions Added Tax that would avoid favouring or penalising any industries, or British economic activity as compared with imports and export markets[56].

This would also have the benefit of rolling up most or all the levies and charges that currently mean that (pre-Ukraine) the cost of electricity accounts for just 20-25% of its price, thereby making the entire system fairer and more transparent[57].

It is true that "*the CfD scheme limits market exposure [and thereby] reduces incentives for plants to operate more flexibly*". But what the report omits is that the CfD scheme is only about energy, not dispatchability, or about balancing, ancillary, stability and restoration services and is therefore not fit for the purpose of incentivising storage.

The "*lack of investment signals for low carbon flexibility*" is correctly identified as a problem, and would be exacerbated by reducing volatility. But, as ever, flexibility is mentioned without duration, thereby making it meaninglessly short-duration (q.v.).

Bespoke support schemes have a place, albeit a limited one. There should be a general scheme such as soft-cap-and-floor to incentivise all storage, but this would incentivise only stand-along storage. The most beneficial configuration of storage is one in which storage of sufficient scale, duration and synchronicity stands between renewable generation and the grid: this will greatly reduce the need to build more grid at the cost of £1.5-1.75bn grid reinforcement per gigawatt of new renewables, plus 10% of that every year thereafter in O&M and financial costs[58] (the benefits would need to be shared between all players, including the grid operator, to provide suitable incentives). These would have to be proposed by developers and rewarded according to the benefits that they offer, without then competing them, because otherwise there

[56] https://www.storelectric.com/incentivising-clean-energy/, cited previously
[57] https://www.storelectric.com/challenges-of-the-electricity-transition/, cited previously
[58] https://www.storelectric.com/saving-billions-on-grid-upgrades/, cited previously

will be little incentive for the developers to bring forward such schemes; competition would remain because any developer can propose such a scheme anywhere, using any technology – they would just be rewarded according to the benefits of that particular proposal. The author has such a proposal on the table, with support from National Grid ESO, Ofgem, a wind farm developer and an analytical company that would create the model; NGET is intransigently refusing to even support analysis into such a scheme and the benefits it can offer the system as a whole and all players (including themselves) within it.

The "*limited market signals for electricity demand reduction*" is because the cost of carbon is so heavily subsidised, and as soon as energy bills rise they are capped and subsidised. Instead, the carbon price should be its full societal cost via an Emissions Added Tax (q.v.), and any support to the poor should be through benefits, which would thereby maximise the "*market signals for electricity demand reduction*".

There is indeed limited or no market for sustained response. There is no contract for reserve services. The Capacity Market is a total failure, with no incentivisation of decarbonisation, 85% of T-4 contracts being merely a second bite of the T-1 cherry, and total values being only 5-10% of the revenue stack needed by storage, which thereby doesn't have enough incentive to build more capacity – and in any case the 4-year lead time doesn't even touch the transmission grid connection lead time, let alone allowing for design and permitting.

Security of Supply

"*The Capacity Market has ensured that sufficient capacity is available to meet peak demand. It has been successful in ensuring the reliability of the electricity system since its introduction."* Only if one looks at the very short term has it satisfied these criteria. But on the criteria against which it was set up, to incentivise new construction, it has utterly failed because (a) only ~15% of contracts are for longer durations than one year and, off those, only a few are for new capacity; (b) its value is too low and (c) the lead time to delivery is too short – see previous paragraph.

Cost-Effectiveness

CfDs, like all other price mechanisms and markets in the electricity system, pays the same per MWh of electricity regardless of its value:

- ♦ Dispatchable and baseload generation is worth more than intermittent, as the latter requires grid reinforcement, curtailment and the procurement (and connection) of balancing services, whereas the first two do not;
- ♦ Synchronous generation is worth more than asynchronous, as the latter requires additional sourcing (and connection) of stability, reliability, resilience and power quality capabilities, whereas the former does not;

- Low and zero emission electricity is worth more than high emission electricity, by the amount of the societal cost of carbon (£450-696 per tonne of CO_2 equivalent[59] – see above);
- Large scale is worth more than small, as the latter requires ever increasingly complex contracting, management, settlement, validation, approvals and control room activities as compared with the former;
- Higher-voltage generation is often (not always) worth more than lower-voltage, as all distributed systems rely on the grid for back-up during times of system stress, so the grid needs to have enough to provide back-up – and having excess on lower-voltage networks would merely cannibalise its revenue streams without removing the need for such higher-voltage capability, thereby increasing overall system costs.

The document is entirely correct that "*current market arrangements do not make efficient use of all assets on the system*", but not for the reasons given. Inertial plant can deliver all stability services at little or no marginal cost when delivering energy, but there is no linking of contracts to ensure that they can be remunerated for doing so. As well as adding greatly to the overall system costs and discouraging investment in highly capable and (over all services rather than by individual service) much more cost-effective plant, It also puts National Grid at risk of legal and contractual trouble, as outlined in the Salami Slicing document[60]. System-wide savings and improvements in reliability and resilience from enabling such cross-service contracts could be very large.

Timing Challenge

There seems to be systemic denial about just how big the timing challenge is. It is formulated solely in terms of securing generation capacity by 2035, oblivious of a variety of other issues of critical importance to the electricity system:

- Securing generation capacity will only cause problems if not matched with storage;
- If that capacity includes interconnectors, then they cannot be relied upon (q.v.);
- Capacity is only a small part of the challenge: non-energy costs of system operation have already overtaken balancing costs, system stability is overtaking energy as an issue, and network capacity / scale is greater than all these together – none of these are raised as issues in the document as a whole, let alone the Timing Challenge analysis;
- Such myopia (the holistic system view looks as far ahead as 2030, only 7.5 years hence) precludes building new transmission-connected plant as grid connections (even without planning and permitting the plants) take at least that long.

[59] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal, cited previously
[60] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf, cited previously

Chapter 3. Our Approach

Approach to options assessment – criteria

Q5: The five criteria are good, as far as they go. But they all have enormous issues in practice.

Least Cost

Least Cost does not define for whom or when. Delivering least cost to consumers today sacrifices tomorrow's consumers[61], as has been done for the last four decades of short-termism, short-duration contracts and under-investment. It needs to focus on least cost for consumers 10, 30 and 50 years hence, not today: today's consumers are a political issue not a regulatory one[62].

In practice it also defines least-cost in terms of very narrow remits[63], for example least cost to deliver inertia (mis-defined to include synthetic inertia, which is very different[64]) or other stability services separately, not grid stability as a whole; to deliver energy balancing without considering also the stability, power quality, reliability, resilience and even restoration capabilities that can be delivered most effectively and at least-cost if delivered by the same plant in parallel. In this way, while the cost of the individual service is procured at the least cost to procure it in complete isolation from all the other services, the overall cost of the system is vastly increased, as is its complexity, hence the exponentially increasing whole-system costs[65].

Deliverability

Deliverability is interpreted to mean deliverable with fewest challenges in making the changes, almost to the exclusion of minimising the complexity of managing the resultant system. For example, the minimum size of plant able to participate in National Grid markets has dropped to under 1% of what it used to be, in order to increase the number of qualifying assets, without consideration of (a) the ever-decreasing impact that ever-smaller assets will have or (b) the ever-increasing complexity to manage the resultant system. Such complexity makes control room, contracting, quality/policing and administrative tasks ever more expensive and difficult, for ever-decreasing gains.

Deliverability must be a go/no-go issue: can it be done? Beyond that, it shouldn't be taken into account, or should be given very low weighting: much more important are the other aspects of least cost in the medium/long term, investability, whole-system stability reliability and resilience, and adaptability for future requirements.

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61 https://www.storelectric.com/wp-content/uploads/2021/03/Issues-with-Ever-Shortening-Contract-Durations.pdf, cited previously
62 https://www.storelectric.com/political-or-regulatory/, cited previously
63 https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf, cited previously
64 https://www.storelectric.com/wp-content/uploads/2020/02/Lessons-for-Europe-from-the-UK-blackouts-v2.pdf, cited previously
65 https://www.storelectric.com/challenges-of-the-electricity-transition/, cited previously

Investor Confidence

Yes, it is important to give investors confidence to invest. For that reason, for example, previous agreements must be respected / grandfathered. And market stability helps improve investor confidence, though this is a lower-order benefit than least cost in the medium/long term, whole-system stability reliability and resilience, and adaptability for future requirements.

The issue is that the market arrangements do not make the grid, large grid-trading assets, or new technologies investable – but they should.

- Almost no large new assets have been built since the last of those planned pre-privatisation, unless they have had 15-year (minimum) contracts for a majority of their trading needs (e.g. ROCs, OFTOs, CATOs, CfDs, RAB, cap-and-floor) – even the Capacity Market T-4 failed dismally to encourage new build because it was too low a proportion of plant trading needs, so it has largely degenerated into a second bite of the T-1 cherry.
  - It should be noted that all these schemes have rules and exclusions, and take the plant out of the general markets, so are market distortions: ways of avoiding such market distortions while still delivering the contract lengths, delivery lead times etc. so badly needed, have been proposed in A 21st Century Electricity System[66].
- New technologies need contracts for their trading needs, covering at least half their asset life, on a lead time (award to delivery) long enough to account for the technology's lead time (planning, investment decision, detailed design, construction) – so EFR encouraged batteries (4-year contracts for 8-year plant life, can be located by existing grid connections) but not long-duration storage (30-60-year plant life, needs new transmission grid connections).
- First-of-a-kind commercial-scale plants need particular support as the financial services industry mis-defines "technical risk" as "first of anything" rather than "risk of a technical nature". Financiers have many sob stories to back this up, of plants that were supposedly sure-fire solutions but failed to deliver technically and/or commercially. Therefore they will not invest in such plants, however much they are needed by the system, without such risk being defrayed.

Whole-System Flexibility

Yet again, flexibility is mis-used without duration. To deliver energy balancing / flexibility, appropriate durations are needed. After sunset on a windless winter evening, batteries will be exhausted by 5pm or 6pm – so no matter how much flexibility they have, without sufficient duration they cannot keep the lights on through the evening peak and overnight.

Yet again, flexibility is considered the be-all and end-all of the challenges of the energy transition. The switch from power station to renewables is not just the switch from dispatchable to intermittent, but also from synchronous to asynchronous, from centralised to distributed, from large to small, from Black Start capable to incapable.

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[66] https://www.storelectric.com/a-21st-century-electricity-system/, cited previously

All of these issues need addressing. And, as they all have a single cause, single solutions should be enabled where – overall – they are the most effective and cost-effective solutions.

Yes, other energy vectors should be considered – but considered as a whole. All too often the analyses and proposals are narrowly blinkered, without considering the wider ramifications. Just four examples will suffice to make the point.

- Electrolysis is put forward by many as a solution to intermittency of generation[67]:
  - Electrolysis hates intermittency, which (a) reduces efficiency, (b) reduces plant life and (c) requires many more electrolysers per unit of hydrogen produced than if fed by baseload or near-baseload electricity.
  - In any case, it only solves one side of the equation, intermittency of input electricity, while ignoring the other side, variability of demand; electricity storage tackles both.
  - It does not insert inertia or the other required services in the grid, unless and until the hydrogen is burned in a turbine to generate electricity.
  - Its whole-system efficiency (renewables – electrolysis – combustion in a turbine – electricity) is too low, having a theoretical best efficiency of low 40s %, realistically achievable mid-30s%, currently mid-20s%, versus (for example) Storelectric's adiabatic Green CAES 68-70% with lower overall plant costs.
- EVs and V2G are considered ideal technologies for the grid, without considering[68]:
  - That grids will need enormous reinforcement, increasing with decreasing voltage, to re-charge them –
    - Fast charging doesn't help because it compensates by taking more current,
    - Flexible charging is of little help because (a) only 60% of households have a dedicated parking space, and many of them don't have enough for their vehicles, and (b) it often takes 6-10 hours to charge the vehicle, leaving little room for movement in time.
  - V2G won't help for the same reasons, as well as further issues –
    - If charging at work and delivering grid services at home, who pays for the electricity and who benefits from the income?
    - V2G also consumes vehicle battery life, which is the most expensive part of any electric vehicle.
  - There isn't enough lithium in the earth's crust for the vehicles of the world, and even less cobalt or rare-earth metals.
- Heat pumps are considered ideal, but little consideration appears to have been put to:
  - The load on the distribution grid, and reinforcement needed;
  - Their deteriorating efficiency, hence increasing load, as external temperatures drop; or

[67] https://www.storelectric.com/wp-content/uploads/2022/07/Hydrogen-and-CAES.pdf
[68] https://www.storelectric.com/electric-versus-fuel-cell-vehicles/, cited previously

- ◊ Their complete cessation of operation at around -8°C, whereafter they would have to be backed up by something else, usually electric radiators.
- ♦ Renewables can't be connected through storage to the grid because they are:
  - ◊ Not credited for the energy being more valuable (see above);
  - ◊ Only credited per MWh delivered to the grid – which would penalise them by the efficiency % of the storage;
  - ◊ Not able to benefit from grid reinforcement avoided, or resultant operational cost reductions;
  - ◊ Excluded from CfDs previously contracted, if storage is added;
  - ◊ Tied into OFTOs, if they want to divert a cable into storage.

Adaptability

The system is very unadaptable at present, for which just five examples suffice:

- ♦ No grid construction to plan, only to proven need, preventing many good schemes being brought forward & possibly tripling overall reinforcement costs;
- ♦ Any schemes that solve problems in ways that differ from grid-identified ways are un-approvable, un-contractable and therefore un-fundable even if benefitting the system greatly;
- ♦ Flexible plants cannot have broad contracts, and salami-slicing increases their commercial risk prohibitively[69];
- ♦ RIIO and (worse) its mid-life assessments impose extreme short-termism in the arrangements that are allowable, as above;
- ♦ Contracting rules do not allow for longer lead-time plants, even if that longer lead time is due to the grid's apparent inability to deliver grid connections in reasonable timescales (largely due to the regulatory rejection of building ahead of need)

Approach to Options Assessment – Organising Options

Q6 The headlines of the options for reform look good. The five core outcomes listed (mass low-carbon power; flexibility; capacity adequacy; and operability) are good as far as they go. The details are grossly inadequate and address only part of the issue. And the organisation of these options creates its own problems and will therefore achieve a highly problematic result. See below.

Q7 When considering options, the principal considerations should be:

- ♦ **Timescale**: will it deliver for 2050 and beyond, including all Scope factors?
- ♦ **Scope**: will it deliver best outcomes for consumers across the entire breadth of the system, including Net Zero, affordability, reliability and resilience, in an integrated manner across all of System Operation, Transmission Operation and Distribution Operation?
- ♦ **Waste**: will there be stranded assets, will there be unnecessary re-work in network reinforcement embedded within the timescales and planning / implementation methods and rules?

[69] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf, cited previously

- **Synergies**: will it enable developments to maximise synergistic benefits for the grid, e.g. cheap stability services while balancing energy, and/or connecting renewables to the grid through storage, and/or enabling cables from renewables to be diverted to storage so as to double (or more) the amount of generation connectable through the given grid connection?
- **Simplicity**; will it minimise the system's complexity and number of assets required to deliver all the Scope, so as to improve cost-effectiveness and avoid the glitches inherent in complex systems?
- **Distortions**: will special contractual arrangements, outside the main contracting structure, be needed? If so, how widespread, and how much does that distort the markets?

There are further Q7 issues broached in the section Approach to Options Assessment, below.

A Net Zero Wholesale Market

An excellent objective. The most technology-neutral way to deliver a Net Zero wholesale market is to price emissions according to their societal cost (see above), via an emissions Added Tax[70]. This would enable each business / consumer to be charged for only the emissions for which they are responsible, while also enabling imports and exports to be balanced so as to avoid disadvantaging the country's industry and services. It also enables emitting industries to remain if they provide particular capabilities that cannot cost-effectively be provided elsewhere, while avoiding favouring some industries for emissions (e.g. shipping, aviation) where a fairer system like this one would encourage more effort to decarbonise. Any other means of doing so distorts or destroys markets.

And the Emissions Added Tax should be set to reflect the societal cost of carbon (see above). Any price lower than that is a subsidy for emitters – essentially, a subsidy for destroying the planet.

Mass Low Carbon Power

Mass low carbon power is another excellent objective. But it is wrong to "*consider options … which will be required to meet carbon budgets*", which will guarantee not only that those budgets are missed, but also that there will be billions of excess costs in the energy transition.

Any major grid-connected asset is likely to have a 30-60-year life. Therefore any asset built now will still be operating in 2050 and beyond. So unless it is Net Zero compatible, it will rapidly become a stranded asset; and if encouraged by government or grid regulation or policy, that stranding of the asset will become a government or grid liability and cost.

[70] https://www.storelectric.com/incentivising-clean-energy/, cited previously

Moreover, at any given carbon budget date, there will be legacy assets that emit more than the permitted average amounts. Therefore all new assets must emit less in order to balance – in fact, to make the sums work, they must emit (almost?) nothing.

Finally, allowing / enabling emitting assets to be built will create / reinforce the pro-emissions lobby and its economic/social power, jeopardising the entire Net Zero strategy to the harm of the entire world. One of their arguments, already present and strengthening, is: why should we emit less than other countries or regions in the world? The answer is because historically we have emitted more, being a disproportionate part of the problem, so it is incumbent on us to be a disproportionate part of the solution.

Nuclear power has very low (life cycle) or zero (per MWh output) emissions. Therefore it should be included – not only small modular reactors (that's "picking winners") but also large plants. They are much better solutions than commonly considered:

- A proper carbon price and proper valuation of electricity (i.e. compensating its baseload nature and its synchronicity) would show them to be very cost-effective.
- 1GW nuclear delivers true baseload electricity and is therefore roughly equivalent to:
  - 3GW offshore wind + 3 GW very long-duration storage (sufficiently long-duration to ride through the kalte Dunkelflaute or similar worst-case weather pattern for each region),
  - 4GW onshore wind + 4GW such storage,
  - 8-10GW solar + 8-10GW such storage.
- In power per square km, in the UK,
  - Nuclear is ~5GW baseload per km^2,
  - Offshore wind is ~52MW intermittent per km^2, capacity factor 45.7%[71]
  - Onshore wind is ~32MW intermittent per km^2, capacity factor 28.3%
  - Solar[72] is ~40MW intermittent per km^2, capacity factor 10.9%

Flexibility

I get exasperated at saying so frequently that flexibility without duration is meaningless, and without the inertia-based services is an exceedingly partial segment of the challenge. See above.

Capacity Adequacy

Capacity can only be adequate if it's always reliable.

- Zero-carbon baseload and intermittent generation (nuclear, biomass, anaerobic digestion and similar) are reliable.
- Storage of sufficient duration to out-last the worst weather patterns is reliable.
- Intermittent generation is not reliable unless supported by such storage.

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71 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1086802/ET_6.1_JUN_22.xlsx using figures for 2020 which are better, as 2021 had lower insolation

72 Based on the Gwernigron Farm in Wales, 117 hectares, 47.5MW

- Interconnectors are not reliable[73].
- Power stations with CCUS would be reliable if (a) CCUS were 100% effective, which it is not, (b) CCUS were affordable, which it is not, (c) power stations with CCUS were cost-effective, which they cannot be, and (d) these costs include the costs and almost eternal risks of CO_2 storage, which they don't[74].

Therefore capacity adequacy can only be delivered according to two very simple, yet totally rigorous, formulae[75] that give the scale of energy storage needed: for power,

> Stored power = {peak demand} + {10-15% supply margin} – {total zero-carbon dispatchable generation capacity}

And for volume,

> Stored energy = {total demand} – {total zero-carbon dispatchable generation}

These must be calculated over the severest relevant "period of system stress", i.e. weather pattern with high demand and/or low renewable generation. For volume this needs to be calculated over he period until there is sufficient renewable generation again to replenish the storage.

Operability

System operability should include many factors that are ignored currently (and in this document), including:

- Complexity for administration, accounting, settlement, trading and control room activities – because the more complex it is, the more failure-prone it is;
- Total system costs, including all energy services, non-energy services (ancillary, stability, reliability, resilience, power quality, restoration etc.) and the size and cost (both capital and operational) of the physical grid;
- System self-renewal: since privatisation, the parts of the system that weren't privileged with 15+-year contracts (e.g. the fleet of power stations) aged by almost a year every year because of short-duration contracts, leaving the country dependent on imports for actual needs and supply margin[76].

There are many more "*barriers for participation in procurement*" than listed in the document – many of them cited above. Most of them would be removed by the simple proposal "A 21st Century Electricity System"[77]; others are subject to current applications for support from BEIS, National Grid and Ofgem.

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[73] https://www.storelectric.com/interconnectors-and-imports/, cited previously
[74] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/, cited previously
[75] https://www.storelectric.com/calculating-the-need-for-storage/, cited previously
[76] https://www.storelectric.com/wp-content/uploads/2021/03/Issues-with-Ever-Shortening-Contract-Durations.pdf, cited previously
[77] https://www.storelectric.com/a-21st-century-electricity-system/, cited previously

Approach to Options Assessment

Assessment of the options should indeed package alternative "solutions" that cover all the many challenges, and evaluate each package in comparison with the others. It is only if each package covers the entire set of challenges comprehensively that the packages can be compared.

The comparisons need to be equally comprehensive. These comparisons are summarised above in the answer to Q7.

There are many factors that are listed in the document which should be ignored in the comparisons. This is supposedly a comprehensive review to come up with the best regulatory and markets system for the grid through the energy transition. Therefore the following matters should not form part of the comparisons, but should be an action plan for change coming out from the identification of the best system:

- Most of the items in Figure 8 (e.g. how paid, how dispatched) are mere features that can be designed into most solutions.
- Other items (e.g. CfDs, cap and floor) are market distortions that are rendered necessary by the inadequacy of the market design.
- Capacity adequacy is much simpler and bigger than indicated – the proposed considerations merely add prescriptive complications to the questions, which should include:
    - Does this country have enough for itself, at all the worst times of system stress, including capacity margin?
    - As distributed systems all rely on the transmission grid for back-up, is there enough on the transmission grid to provide that back-up, for all durations?
    - Given that amount on the transmission grid, how much distributed resource is beneficial, and what is the threshold above which it merely adds to system cost by eating into the revenue stacks of transmission-connected assets?
    - Does the system (physical network and trading) make best use of the assets?
    - Does the system pay for the renewal of the asset base without any market-distorting incentives?
- Operability should be all about how to make the optimal system work, not how to minimise the cost and hassle of change to it. That minimisation is to be done later, in determining the pathway towards the optimal system.

Chapter 4. Cross-Cutting Questions

Q8: No, only a small proportion of the key cross-cutting questions and issues have been identified. Some of the more notable omissions include:

- The grid network, which accounts for over half of the exponential increase in non-energy costs of the energy transition, and which has major interactions with System Operation, renewable generation and demand issues, such demand including electrolysis and other hydrogen / synthetic fuels and chemicals matters;

- The interplay between network issues, system operational issues and the energy transition of (currently) non-electric systems such as heating, transportation and industrial processes, for example
  - ◊ Most analysts believe that National Grid under-estimates future Net Zero electricity demand by a factor of 2 or 3 because of the electrification of such systems, electrolysis, increasing gadgetisation etc.,
  - ◊ To electrify heating and transportation would require massive investment in grids, increasing with decreasing voltage,
  - ◊ Electrifying heating must take account of the deterioration in performance of heat exchangers as ambient temperatures drop, eventually failing at about -8°C and thereby putting an immense surge load (mainly on the lower levels of the distribution grid, with consequent surging demand throughout the network) for direct electric heating onto the grid at times of peak demand to power everything else as well;
- The complex interplay between energy and non-energy System Operational issues, which requires an equally integrated approach to tendering and letting contracts;
- The relevance of duration to energy balancing / flexibility, consistently ignored – though providing many GW flexibility with durations between half and two hours will be exhausted by 6pm on a windless winter evening, leading to widespread black-outs – and such storage with 5 minutes' duration is useless for most purposes;
- The long lead times to implement solutions and projects that will optimise the energy transition for cost, reliability, resilience, recovery and power quality;
- The interplay between distributed systems / generation / storage, which reduce overall grid load in normal times, and transmission-connected systems / generation / storage, which power the major parts of the economy and provide the back-up to distributed parts, and the thresholds above which excessive distributed parts cease to add capability while adding costs to the overall system;
- The differences between behind-the-meter and in-front-of-meter storage for large-scale renewable generation, the former (especially if the storage is synchronous) delivering whole-system benefits an order of magnitude greater than the latter though it is currently penalised – and there is no suggestion in the document that such penalisation is going to be transformed into incentivisation and monetisation of benefits;
- The operational life of the assets in question, their performance / deterioration during their life, and the complexity of managing such deterioration for those systems (especially involving batteries and power electronics) during that life;
- The need to support first-of-a-kind commercial-scale plants of all technologies.
- More details below.

Q9 The trade-offs identified are deficient in scope and scale, and (by their failure to address the majority of the cross-cutting questions) don't consider all the appropriate factors that must be traded off against each other, and therefore cannot consider the most appropriate approaches.

The Role of the Market

The document claims that "*Market forces are a central part of the electricity system.*" However, since privatisation – apart from a few plants planed pre-privatisation – almost no infrastructure-scale developments with infrastructure-scale operational life have been built without special financial instruments delivering 15+-year revenue certainty, e.g. CfDs, ROCs, Capacity Market, RAB, CATOs, OFTOs. Every single such instrument is not only a market distortion in itself but also a reduction and distortion of the action of the residual market. And the fact that some technologies (e.g. offshore wind) are included but others (e.g. storage, onshore wind) are excluded distorts the market even further.

Another market distortion is the subsidy given to fossil fuelled generation by failing to charge the societal cost of carbon, which is at least 10x the current carbon price.

Another market distortion is the fact that the price paid for electricity in no way reflects its value. A MWh of electricity is paid the same whether it's dispatchable, baseload or intermittent – though intermittent generation requires additional procurement of balancing services, and network to connect up such services – or whether it's synchronous or asynchronous – though asynchronous generation requires additional procurement of stability, reliability, resilience, power quality and system restoration services, and related network to connect them up. Until electricity is remunerated for all the services it provides, the non-energy system costs will continue to rise exponentially[78].

Logically, there are only two coherent positions that can be taken with any consistency, and with any hope of controlling system costs, reliability and resilience: all market, or all control.

- **All Market** requires the construction and operation of a market that procures all energy and services together[79], and rewards developments for all benefits including those to the network/grid, and allows for suitable lead times to build any of the competing technologies;
- **All Control** requires the determination of whole-system requirements, and the mandating and financing of each of them, e.g. with special financial instruments for all. This would be compatible with market-like mechanisms for legacy plant and for plant that lasts longer than the special financial instruments. However, historical failures of centrally planned economies showed the dangers of such an approach.

The current system is an evident failure from most perspectives; e.g.

- Although the government identified in 2012 an urgent need for up to 59.2GW electricity storage with average durations of 5 hours, with increasingly urgent reiterations of need of a similar order of magnitude from all sources including the grid, not a single MW has been built with such duration in the decade since.

[78] https://www.storelectric.com/challenges-of-the-electricity-transition/, cited previously
[79] E.g. https://www.storelectric.com/21st-century-electricity-system/, cited previously

- While the regulator almost invariably cites the needs of "the consumer", they never define which consumer: today's, in 10 years' time, or in 30? As a result of this they sacrifice the consumer of tomorrow on the altar of today, hence short-term and narrowly-defined contracts for individual services that obtain the cheapest price today but lead to no investment in capability outside of special financial instruments.
- This short-termism has led to a deterioration in the UK's electricity system from being Europe's second cheapest and one of its most reliable with plenty of surplus capacity, to the continent's second most expensive, of sharply deteriorating reliability and reliant on imports each winter for actual system needs as well as for supply margin. This is proved by the reversal of interconnector flows during the Ukraine crisis leading to turning on coal-fired power stations: had the same occurred during winter peak demand, the country would simply not have had the capacity after sunset on a windless evening, with resultant widespread black-outs and brown-outs.
- For these reasons, non-energy system costs are rising exponentially and in an uncontrolled manner: any control is merely fire-fighting that is destined to be overwhelmed by circumstances a few months or years into the future, as has always occurred in the past.

The "*assessment … that market forces alone are currently unable to deliver our objectives*" is solely because of the poor market design and the hotch-potch of special financial instruments cobbled together to make up for its inadequacies. But there appears to be no appetite for the radical market redesign that is required to solve this – even if it can be introduced gradually.

Extent of Competition Between Technologies

"*Effective competition between technologies is a key driver of delivering a least cost capacity mix.*" Yes, but only if they can compete on a level playing-field: see above for some of the many market failures such as not being remunerated for the services offered.

Another result of these market failures is the mass of legal impossibilities it creates. Consider a technology that can only deliver service A with service B (e.g. a synchronous plant that can only deliver energy with inertia). If they (supplier 1) win the contract for A but not B (won by supplier 2), then what happens?

- If the System Operator takes service B without remuneration, they will be sued by supplier 1 for theft and also by supplier 2 for breach of contract.
- If the SO pays for B, then 1 is happy but 2 still sues.
- If the SO penalises 1 for B to pay 2, then 2 is happy but 1 can no longer deliver A.

Again, if supplier 1 can deliver B more expensively on its own than supplier 2, but can deliver it very cheaply if also delivering A, then the cost to the whole system of contracting both A and B from 1 is cheaper than contracting the two separately.

Again, if supplier 1 can deliver A, B and C much more cheaply together than individually, they must bid sufficient margin on each service to account for the commercial risk of not winning one or two of the contracts; yet that margin (a) increases the overall system cost without increasing system capability and (b) may well make supplier 1 uncompetitive for each of its services when it is the cheapest and best supplier if all three were contracted together.

Design of an effective system "*that appropriately values all the attributes that the electricity system needs, and fairly takes into account the very different characteristics of participating technologies*" is actually easy, not "*difficult*" – it must be tendered, bid and evaluated on a matrix basis as described in A 21st Century Electricity System[80]. And it is simple enough to do on a spreadsheet – though a database would make it easier for such a large electricity system with so many bidders and factors to bid.

Extent of Decentralisation: Where Decisions are Made

Of the two options (All Market, or All Control), the former puts most of the "*decisions in the hands of a more dispersed set of market participants*", while the latter centralises most. It is the government's choice which way to proceed, but it is one or the other, not some ungainly hybrid of the two such as we have now. The market approach is almost invariably superior, provided that the market is designed with all the major factors taken into the market mechanisms. The centralised approach is appropriate where the complexity of the market mechanisms is too great, and/or when the required pace of change is too urgent; though government does not tend usually to be faster than markets.

Decentralisation would also mean that the system is open to new ideas and ways of approaching needs that have been identified as outside current market mechanisms. An example of this is that in today's markets, synchronous storage of suitable scale and duration between renewable generation and the grid is currently penalised[81], instead of being rewarded for the massive savings it can deliver to the grid, system operation and consumers[82]. In such cases the government, grid and regulator must be open to developing new such mechanisms to keep the market fit for purpose.

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[80] https://www.storelectric.com/21st-century-electricity-system/, cited previously

[81] Penalisation takes many forms, including:

- Each MWh is paid for when it gets onto the grid; if storage is between, then the MWh produced are reduced by the storage efficiency factor, despite the increased value of the services and the reduction in whole-system costs.
- CfD rules would result in reduced CfD payments to the renewable generator.
- There is no way for the plant to benefit from the reduction in grid network costs.
- Life-of-plant contracts are needed for both network and System Operation, as the storage cannot be removed from its position between the renewables and the grid at the end of a contract: the grid connection size would be insufficient.
- If diversion of an existing wind farm's cable through the storage would result in a new farm being able to connect without a single GW of new network capacity, then in addition to all the above, OFTO rules and structures get in the way.

[82] https://www.storelectric.com/saving-billions-on-grid-upgrades/, cited previously

Role of Marginal Pricing

In a comprehensively and well-designed market system, there would be long-duration contracts for new plants, medium-duration contracts for major investments and short-duration (marginally priced) contracts open to all. The long- and medium-duration contracts would therefore be totally decoupled from the gas price. And if gas were charged the societal cost of emissions, then even marginal pricing would be totally decoupled from it as nuclear or renewables + storage would deliver more cheaply. Likewise, marginal pricing on the matrix model which remunerates all the relevant services would again decouple the market from gas.

Minimising Financing Cost and Maximising Operational Signals

Financing cost is directly related to commercial risk. The more the contracts defray commercial risks, the lower the financing costs. This can be achieved by contracting in advance, for example, for:

- The full range of services;
- The life of the plant (in other words, the longer the contract, the cheaper its financial cost);
- Long enough before deliver to allow for plant construction and grid connection;
- With lead-time flexibility in case the grid fails to deliver grid connection on time;
- Index linked, so financiers don't have to make assumptions (which will always be conservative, i.e. high) on inflation (the most appropriate index will need to be selected, though CPI or RPI may well suffice);
- Eliminating or capping risk of losses;
- Permitting up-side benefits, e.g. a "soft cap" in cap-and-floor, discussed above, which maximises simultaneously the role of markets, pay-backs to consumers, and potential profits.

Not all of these factors need to be present, but the more are present, the lower the financing cost will be.

More Accurate Price Signals and the Benefits for Consumers

Under the "All Market" option, price signals would run the system and do so very well, because all the important factors would be remunerated in an integrated manner. It would be hard but not impossible to design an "All Control" system led by market pricing.

In the document there seems to be a confusing conflation of energy costs and system costs, equating non-use of energy with non-use of the system. Where consumers self-generate and even self-store, they are still using the system – but doing so for back-up. They rely on the system to provide what they need when their generation is nil and their storage exhausted. But to do this, the system needs to maintain not only grid capacity but also the capacity of generation, storage and other services. All this capacity needs to be paid for – not just to build it but also to maintain it at the ready for whenever it is needed. This implies that consumers' bills need to be weighted more heavily towards standing charges, based on size of grid connection, and less heavily on kWh consumed. This would be more progressive than today's regressive system in which those consumers rich enough, and with big enough properties, to build

distributed generation and storage don't pay for the system back-up services; those costs then fall on the consumers without such means.

The scale of change: delivering our objectives throughout the transition

The proposals are all about delivering 2035 objectives, with little to suggest that they benefit 2050 ones. The market needs to be designed for the 2050s – and the market design proposals aren't fit for the 2020s[83], let alone the 2030s. Whether it's revolution or evolution, a "fit for purpose" market design needs to:

- Remunerate benefits to the system as a whole, not to narrowly defined sub-sections of the system (e.g. SO not TO, or single services within the SO, or emissions benefits being unremunerated etc.);
- Focus primarily on the medium (10-30 year) and long (30-50 year) term costs and capabilities, with the short term being within the remit of market regulation and politics[84];
- Incentivise new construction with long-duration contracts, as well as ongoing operation with short-duration ones, without market distortion by special financial instruments;
- Incentivise large and highly capable plants as well as small and narrowly capable ones;
- Enable plants of all sizes to be built and connected to the grid before being obliged to deliver on contracts (i.e. either extending contractual lead times or, better, guaranteeing grid connection within the plants' construction lead time);
- Avoid creating legal impossibilities such as an inertial plant winning contracts for energy but not for inertia and related services that cannot technically be divided from the energy delivery;
- Deliver an energy system in which the country is entirely self-sufficient, including supply margin, with all stability reliability resilience power-quality and restoration services, during the most extended times of system stress;
- Remunerate benefits that the network derives, together with those delivered to system operation – by linking Network Operator and System Operator contracts if need be;
- Minimise the long-term network costs as well as long-term system operation costs – by linking Network Operator and System Operator contracts if need be;
- Facilitate the adaptation of legal entities (e.g. OFTOs) for changes of use (e.g. to divert to storage so that an additional wind farm can be connected through the same grid connection);
- Incentivise the construction and connection of first-of-a-kind commercial plants of any technology that can justify that it is likely to benefit the system as a whole.

The consumer of tomorrow must not be sacrificed on the alter of today's consumer, as they have been since privatisation by short-term contracts, sweating grid assets,

[83] https://www.storelectric.com/where-grid-regulation-went-wrong/
[84] https://www.storelectric.com/political-or-regulatory/

refusing to build ahead of need, procuring from cheapest sources on spot and short-term markets rather than on medium- and long-term markets, allowing security of supply to degenerate to such an extent that we cannot even provide for our own actual demand during times of system stress (and still less, provide for our supply margin), allowing system reliability and resilience to drop towards developing-country levels (still better than most, but some have surpassed us especially in East and Southeast Asia), and so many other problems.

The resultant changes are likely to be a mix of revolution and evolution: think of it as punctuated evolution.

Delivering / introducing more accurate locational signals

In the power industry, profits are typically in the low single digits of percent of turnover. Therefore small locational signals will have a big effect on plant location for those that (like batteries) can choose their locations freely. However, most (e.g. consumers, pumped hydro) cannot choose their locations freely, so should not be destroyed by excessive locational pricing.

If locational pricing is large (i.e. more than ~5% of turnover of a plant), then effectively a single 55GW market will be shattered into a huge multiplicity of mini-markets in which large plants cannot compete as they would dominate. The effect would be like closing all supermarkets, and replacing them with a myriad corner shops: costly, ineffective, reducing choice resilience and flexibility, and a retrograde step that would effectively take us to the early years of the grid (or, if locational pricing is >25% of turnover) to before the existence of the grid. The clock would be turned back by 80 years or more.

This implies that a small degree of regional (less zonal and very little nodal – too small) pricing could be introduced to renewable support schemes and/or capacity adequacy mechanisms and network access, but not to wholesale or imbalance pricing.

What would happen to a plant that builds in a location because it's incentivised to do so, then the grid in that location becomes congested so its locational pricing is increased? Then the plant would be penalised for having responded to prior signals. If those signals are large, they could be enough to bankrupt the plant, merely by regulatory whim. This uncertainty could destroy the financial security and therefore investability of plants even in locations where the grid would rather encourage them.

Many plants (especially large and highly capable ones) can deliver benefits outside their immediate zone. For example, large-scale storage in Scotland can alleviate congestion in England. Locational signals should remunerate such benefits.

Question 10: The most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage is by keeping such pricing small, to <5% of turnover, keeping the scale larger (mostly regional, some zonal and very little nodal) and by focusing it on renewable support

schemes and/or capacity adequacy mechanisms and network access, but not to wholesale or imbalance pricing.

Question 11: Market participants will be as responsive as they can be to small locational signals, because profits are typically a small percentage of turnover. On the other hand, many plants (consumers, generation, pumped hydro, CAES etc.) have little or no locational choice and would merely be penalised for existing. And as locational pricing changes, so legacy plants would be penalised for having responded to previous signals. This would destroy all plants' investability, even in locations where they are needed now.

Electricity demand reduction, and possible approaches

Demand reduction benefits the country and world greatly. But it dis-benefits the energy systems which are incentivised to deliver more energy. It is not the place of energy systems to deliver outcomes such as heating pr lighting a home or office to a certain level: that is the occupant's choice.

Incentivising demand reduction by focusing costs onto MWh consumption, even if varying in time through smart meters, yields many and complex problems. For example, it incentivises those wealthy enough to invest, or to have their own house (as opposed to rented or shared accommodation, or flats), or have the space (e.g. to install thermal / electrical storage) by putting the costs of that incentivisation on the disadvantaged. It also means that those richer people, who depend just as much on the grid for back-up in times of system stress, are not paying for sufficient capability to be available on the grid – whether in terms of generation, balancing, other services, substations or wires.

Therefore, to reflect the use people get from the grid, standing charges (which pay for this back-up capability) need to rise and energy charges fall correspondingly. But this goes in the opposite direction from incentivising demand reduction.

Question 12: Therefore demand reduction must be a political decision, remunerated outside energy industry regulation.

Chapter 5. A Net Zero Wholesale Market

Challenges and opportunities of the status quo

The Status Quo charges a carbon price that equates to between 1/6 and 1/10 of the societal cost of emissions. Until that is rectified, any intervention will be a market distortion. These market distortions take many forms, which are essentially one (or both) of regulatory fiat (e.g. putting a carbon intensity cap on suppliers, or green market cut-out) and subsidy. Whatever form they take remains a market distortion.

Better is to (more details here[85]):

- Charge the societal cost of emissions (to avoid subsidy) …
- As an Emissions Added Tax (so each technology is charged for the emissions they add, not those they trade, e.g. zero-carbon storage would add none whether the electricity they store is clean or dirty) …
- With much of the proceeds going to needy consumers (so that they don't lose out) …
- As an energy-unrelated payment (so as to maximise the incentive to reduce consumption / emissions).

Liquidity

Liquidity is created by having large markets without market-distorting special financial instruments. Large markets mean that locational pricing must be small. Avoiding special financial instruments means that the market / system / regulatory design must incentivise all the right things: see above, in the section "The scale of change: delivering our objectives throughout the transition".

Operational signals for flexibility

Please see the above comments on locational signals.

Question 13: No, not all the credible reform options are being considered. There is no consideration of:

- Long-duration contracts;
- Contracts linking services that cannot (or cannot cost-effectively) be delivered apart, e.g. for naturally inertial plant, energy contracts cannot be delivered without also delivering inertia and related services, and reactive power/load, and frequency/voltage regulation, and power quality services – but supplementary delivery of such services may be possible (and separately contracted) when energy is not required;
- Integrating contracts where there is a major benefit in doing so; e.g. if an inertial plant has an inertia contract, then it is spinning and synchronised, making delivery of frequency/voltage control and reactive power/load both cheaper and more rapid-response;
- Letting contracts based on optimal whole-system outcomes rather than narrow service-by-service immediate-term criteria;
- Engaging in contracts that provide sufficient lead time for large and/or highly capable plants to be built and connected to the grid, especially to the transmission grid whose lead times are often 7-10 years or more;
- Remunerating benefits derived by the network (transmission or distribution system);
- Integrating contracts that deliver both system operation and network benefits;
- Whole-life contracts where the benefits being delivered mean that the plant cannot be removed from the system, e.g. if it halves or eliminates grid

[85] https://www.storelectric.com/incentivising-clean-energy/, cited previously

reinforcement for a wind farm, it cannot be removed without first undertaking such reinforcement and thereby losing the benefits.

Splitting the market

Splitting the market for variable and firm power is very much a least-worst option. There are many options that are better. Splitting the market into carbon and no-carbon markets may in the short term guarantee contracts for zero-carbon technologies, but also does the same for emitting technologies that we need to close down as fast as possible.

The best option would be to impose a carbon price that is commensurate with the societal cost of carbon[86], especially by an Emissions Added Tax, and supporting those who cannot afford the price increase[87]. This can be done purely for the energy system, though some would try to circumvent it by investing in their own in-house generators; it is better done for the economy as a whole. But doing it for the energy systems alone is second best. And for the electricity system alone is third best.

Fourth best would be to impose a levy on all emitting technologies on the emissions that they add, i.e. so storage only pays if it adds emissions, and is not penalised for the carbon intensity of the grid as a whole which it cannot affect.

Fifth best would be to have a single market and evaluate all zero-carbon offers before allowing any consideration of offers emitting generation; and then the emitting generation would be considered (in broad bands) based on how much they emit per unit output, the lowest first.

Combined with any such arrangement or (sixth best) separately, the value of electricity should be remunerated. Baseload and dispatchable are worth more than intermittent (the relative values of baseload and dispatchable need to be calculated); and synchronous is worth more than asynchronous, as described above (Extent of Decentralisation: Where Decisions are Made, and footnote). Such value-based remuneration would be a natural outcome of linked contracts assessed on whole-system costs and benefits.

It is only if all these (and probably many variants of them) are rejected that splitting the market becomes attractive.

The four perceived benefits of splitting the market are all vastly inferior to those same benefits as provided for by the other options outlined above.

1. Decoupling electricity prices from gas:
    - There are many better ways of performing this de-coupling, especially long-duration contracts which can be at set (indexed) prices.
2. Discovering the value of flexibility:

[86] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal/valuation-of-greenhouse-gas-emissions-for-policy-appraisal-and-evaluation
[87] https://www.storelectric.com/incentivising-clean-energy/, cited previously

- Again, flexibility without duration is utterly meaningless;
- It doesn't "discover the value of flexibility" – it only discovers the available quantity of flexible output as a proportion of that sub-market's defined size, and compares that with the quantity of inflexible output as a proportion of that sub-market's defined size;
- Already the edges have been blurred in a logically un-tenable way by permitting intermittent generation to compete on flexibility and ancillary services markets despite the fact that they cannot guarantee to deliver the services when called upon to do so;
- It ignores the non-energy benefits such as (applying to the system, rather than to the producer) stability, reliability, resilience, restoration, power quality, Black Start – all of which (together) are more valuable and costly than balancing services and flexibility as currently defined.

3. Incentivising demand-side flexibility by arbitrage:
    - All distributed systems rely on the grid for back-up; incentivising further distributed generation without charging sufficiently in standing charges places the cost of provision of that back-up capability on those least able to afford it (see Approach to Options Assessment – Organising Options – Approach to Options Assessment, and More Accurate Price Signals and the Benefits for Consumers);
    - Do you really want to incentivise investment in behind-the-meter diesel generators?
4. Avoiding government support for investment:
    - It will not do this unless contracts are of sufficient duration and lead time to first deliver (or, better, the grid guarantees to connect them within their construction lead times) – and these aspects can be delivered better without splitting the markets;
    - And, if capable and flexible plant is wanted, linked contracts will be needed.

Therefore these are NOT substantial benefits, and cannot be set against the potential downsides that the document lists, unless all the better options outlined above are runed out. And there would have to be exceedingly strong logical reasons for ruling out the better options, not just the present obsession with short-term contracts and worship of today's consumer at the cost of tomorrow's.

I note that the paper sees a downside of splitting the market in two as being to reduce liquidity and reduce competition (third bullet, downsides, repeated in last bullet). That applies much more strongly to regional and nodal markets, which would split the market into much smaller fragments.

The lauding of "engaged consumers" is wrong-headed too: only a minority of consumers have the ability and desire to be engaged and, of them, hardly any will be earning little enough for the proffered incentives to make any substantial difference. Instead, all policies should focus on disengaged consumers who only want to have the lights, heating, cooker etc. come on when they turn the switch; environmental and grid benefits and incentives are all very secondary or tertiary issues to them.

Question 14: Not unless you have eliminated every single other option, and all the options listed above are better.

Question 15: By choosing one of the better options I list above.

Introducing locational signals, Locational wholesale pricing

This is the third or fourth time the document has proposed locational signals, and this time is "introducing" them, making it appear that you are not consulting at all, just pretending to do so, and in fact you have already made up your mind. Please see the sections above REMA Objectives / Locational Signals, Delivering / introducing more accurate locational signals, and the note on locational signals in Splitting the market. Beyond about 3-5% of the cost of electricity, it is a bad idea.

Additional to all that is the fact that such locational markets would enormously increase the cost and administrative burden of managing them, as alluded to in the discussion on nodal pricing; the same would apply, to a lesser extent, to zonal pricing.

Question 16: No, neither locational nor zonal market designs should be considered. Any such price signals should be restricted to 3-5% of total energy prices, or they will vastly increase both complexity and cost of the energy system, while undermining its integrity, reliability, resilience and energy security. It would also make investment decisions almost impossible as future prices within each zone would be much more volatile. And most generation, demand and large-scale long-duration storage is not able to select its location to respond to such price signals, so the benefits derived from such a policy would be a tiny fraction of those imagined within the report.

Question 17: By limiting nodal and zonal price signals to 3-5% (in aggregate) of total energy prices.

Question 18: No. The same disadvantages would merely be replicated at smaller scale: at transmission level you're (by analogy) closing all supermarkets to supply all needs from corner shops; at distribution level you're closing the corner shops to supply all needs from a barrow.

Introducing locational signals: local markets

Are you obsessed with it? Can't you just discuss it once and have done with it? Stop repeating yourselves and harping on about it – or stop pretending that you're consulting!

Question 19: No, for a thousand good reasons stated a dozen times before in this response.

Question 20: No, again the markets should be kept large and integrated, or you're going back a hundred years in the development of the grid.

Moving to pay-as-bid pricing

The best plants delivering the best services should be the most profitable. Pay-as-bid does not deliver that, whereas pay-as-clear does.

Decoupling from gas should be achieved by pricing the emissions to reflect the societal cost of emissions, as discussed above. Pay-as-clear should remain.

Ignore the CCUS red herring: it'll never happen. CCUS is too expensive, inefficient and dangerous, three factors that are consistently ignored by its advocates[88].

Question 21: No, because that will prevent the best plants being the most profitable. There are much better ways to discourage gas, such as charging the societal cost of carbon. In a snort term, prices can be decoupled from gas by awarding contracts as at present but setting the prices for non-gas separately from gas. This doesn't involve splitting the market: all bid into the same market. Nor does it pre-determine the proportion of gas (or coal) and non-gas (or coal). Instead, once the volume contracts are determined, set one "pay as clear" for gas and coal, and another for the rest.

Evolving the Status Quo

See my response to Question 13 for the most important of the many substantial changes needed to the electricity market arrangements in order to make a Net Zero system affordable, reliable and resilient, and providing energy security. As stated above, some of these can be incremental and some in substantial changes: punctuated evolution. Or they can be implemented as a "big bang". Which method you choose is nothing like as important as actually choosing to do ALL those changes, and doing so fast – within 2-3 years for most, if not all, of them. The system is so broken, the costs rising so fast, the fragility of the system developing so quickly, energy security so urgent, and the disincentivisation of the necessary investments (especially large-scale, long-duration, preferably naturally inertial storage) so extreme (which is why none has been built since a need for up to 59.2GW of it was identified a decade ago in the TINA[89])

Question 22: You have been prevaricating for years, now is the time to decide. You have been pursuing short-termism, salami-slicing, building grid responsively to need, separation of contracts, avoidance of remuneration of whole-system benefits, short-duration contracts, contracts with short lead times to delivery etc. for decades, which is what has delivered a deterioration of our electricity system from surplus to depending on imports for actual demand and supply margin, from reliable and resilient to fragile and many near-miss blackouts annually, from Europe's second cheapest to one of Europe's most expensive. All these principles need to change urgently in order to stop and reverse the inevitable collapse of either the system or the energy transition.

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[88] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/, cited previously
[89] https://www.carbontrust.com/resources/tinas-examining-the-potential-of-low-carbon-technologies Energy Networks (Part D), Chart 2 p9, consider the storage totals (ignoring their projected breakdown of technologies), divide GWh by GW and you find that the average duration of the required storage is 5 hours; none has been built since then. Published in 2012.

Question 23: Yes. See my answers to questions 13 and 22, as well as the rest of this document. (Copy and paste those answers into this answer in your log.)

Chapter 6. Mass low-carbon power

Challenges and opportunities of the status quo, Options assessment summary

The analysis states that "*support is needed because – due in large part to the phenomenon of price cannibalisation – wholesale market revenues alone will not be sufficient to deliver the unprecedented volumes of investment we require*." This is correct (though only part of the reason why support is needed), yet the proposed pursuit of untrammelled amounts of distributed systems and of salami-slicing contracts will merely make such cannibalisation worse. It is inconsistent to seek to minimise support while pursuing such policies.

As noted above (see especially ***The Role of the Market*** and ***Challenges and opportunities of the status quo***), every special financial instrument (e.g. CfD) is a market distortion, not only for the technologies covered but also for those not covered as the residual market shrinks. The policy should be either to ensure that the market arrangements minimise or eliminate the need for such distortions, or to put in place comprehensive strategies, policies and contracts covering all the system's future needs. Either would work; the former would be much more cheap, efficient and easily managed. But today's system falls between the two and is therefore the worst of both worlds.

CfDs are fine if all that's wanted is energy. They pay nothing for having that energy when needed (dispatchability) or for any of the other grid services that many types of generation and storage could supply, such as stability (especially when based on real inertia), balancing, ancillary, congestion alleviation, resilience and restoration services. CfDs are therefore only suited to intermittent, asynchronous generation and maybe extendable to asynchronous storage; they are not suited to anything synchronous, especially if dispatchable or baseload too. For these, the most suitable arrangements, in descending order of preference, are[90]:

1. A suitably designed set of market arrangements[91];
2. Floor only;
3. Cap and floor, with soft cap;
4. Regulated asset base;
5. Cap and floor, with hard cap.

Question 24: No, not all credible options have been considered. Regulated Asset Base is ignored, and only one version of cap-and-floor rather than the three versions

[90] https://www.r-e-a.net/resources/rea-longer-duration-energy-storage-report/
[91] https://www.storelectric.com/21st-century-electricity-system/, cited previously

of no cap, soft cap and hard cap. And the best arrangement possible, a suitably designed set of market arrangements such as are summarised in the document A 21st Century Electricity System[89], is ignored: it is a simple, practical system that encompasses all the appropriate incentives for investment, environmental friendliness and introduction of new technologies without requiring a penny of subsidy; however that would require strategic, long-term and joined-up thinking which appear (from the evidence of "strategic" proposals (including this one) that look ahead just 7 years to 2030 and "comprehensive" ones (including this) that consider system operation separately from network operation and cannot countenance the integration of contracts or the evaluation or remuneration of whole-system benefits of any proposal) to be beyond those who regulate and operate the electricity system.

Question 25: Valuing low carbon requires proper evaluation and charging of emissions, whether by financial charging, by length of contract, by prioritisation in contract awards or by a combination of these, and also requires that only the added emissions are charged to any plant; none of this is considered. Valuation of wider system benefits of anything requires that services that can only be delivered in combination are given combined contracts; benefits that require long lead times are given them; benefits (e.g. major capital investment) that require long-term revenue security are given long-duration contracts; benefits that cross regulatory boundaries (e.g. DSO / TSO / DNO / TO) are remunerated with linked contracts that encompass them all; and that evaluations are based on whole-system benefits. A simple matrix system for doing this, and all the other requirements, is summarised within A 21st Century Electricity System[89]. // But the question also carries the assumption that "small-scale, distributed" is intrinsically desirable: it is not. All distributed systems rely on the grid for back-up, so the grid must ultimately carry sufficient capacity and capability to provide such back-up for as long as is required. Such capacity and capability needs to be paid for, but if distributed systems are cannibalising these, then those lost revenues will have to be recovered by putting up prices. There is therefore a threshold (to be calculated) above which additional distributed capacity will merely add to costs without increasing capability.

Grouping options

Again, this only considers energy. This is only a quarter (very roughly) of the excess costs of the energy transition. Another quarter is the non-energy costs of system operation, and a half is the network reinforcement and adaptation. These aspects are intrinsically bound up with each other and should not be addressed separately. All arise from the move from large rotating generators to intermittent renewables and interconnectors. Large rotating storage can address all of them concurrently, much more cheaply, reliably, resiliently and sustainably than addressing each factor separately. So if systems, processes and contracts are not able to cross these artificial silo boundaries for plants that can (and must) cross those boundaries, the system as a whole will be greatly sub-optimised at exorbitant cost[92].

[92] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf, cited previously

Supplier obligation

Question 26: Supplier obligations will pass down government and system decisions to organisations that have no governmental or system responsibilities and are therefore very ill suited to take them on. Their focus and incentives are narrow, short term and restricted to the supply of energy; maintaining, building and operating the system are others' responsibilities. Moreover, disaggregating demand down to supplier level will have all the disadvantages of fragmenting one large and liquid market into scores of tiny, fragmented markets: large and broadly capable solutions will be enormously disadvantaged in comparison with small and narrowly capable ones, and the medium and long term interests of the country, system and consumer would be sacrificed entirely to those of today's consumers and profits.

Question 27: The only way for a supplier obligation model to be effective is to ensure a monopoly supplier with whole-system and network responsibility. That would be nationalisation, which is not on the cards. Any alternative, to have even the slightest possibility of working, would tie suppliers in so many legislative knots that it would be tantamount to privatisation without the benefits of it, such as lower costs of money.

Question 28: There is no way to overcome the financing and delivery risks of a supplier obligation without creating a monopoly integrated system operation and network supplier – which is tantamount to nationalisation.

Central contacts with payment based on output

Question 29: The need is not for outputs alone, as defined herein. There is also need for availability and reserve. And outputs must not be measured as energy alone, but also non-energy system operating needs and network needs (both operability and scale).

Question 30: No, the ***dis-***benefits of increased exposure are likely to dwarf the increases in system financing costs.

Question 31: Yes.

- If contracts are short duration, long-lived and large-scale plants will not be built.
- If contracts are narrow, broadly capable plants will not be built.
- If contracts are too immediate, long lead time plants will not be built.
- If contracts are for energy, system operation will become impossible.
- If contracts are for energy and system operation, the network will have to at least triple in size[93].

[93] https://www.breakthroughenergy.org/scaling-innovation/modeling-the-grid: the grid needs to triple in size to accommodate renewables. It's too expensive for USA, so what hope would we have? https://www.mckinsey.com/business-functions/operations/our-insights/global-infrastructure-initiative/voices/upgrade-the-grid-speed-is-of-the-essence-in-the-energy-transition: "The energy transition will require a dramatic increase in capital spending on the electric grid, delivered at an unprecedented pace." https://www.nationalgrideso.com/research-publications/network-options-assessment-noa/network-development-roadmap: adding estimates for the procurement of grid operability, £1.5-1.75bn grid reinforcement per GW of new wind connected by 2030; plus procuring

Central contracts with payment decoupled from output

As outlined before (see Challenges and opportunities of the status quo, Options assessment summary above), CfDs are inadequate: they're for energy alone, not for everything else that the system needs. A more comprehensive approach is required (see Question 13 above).

But these are NOT decoupled from output, especially if the cap is soft. Outputs need to be defined not just as energy but also as:

- Dispatchability (balancing services, arbitrage etc.)
- Duration
- Speed of response (ancillary services)
- System operability (voltage and frequency control, reactive power/load etc.)
- System stability (real inertia, leakage currents etc.)
- Resilience (various restoration services, e.g. as tendered by DNOs)
- Black Start
- Constraint alleviation
- Alleviation of other network costs such as curtailment, grid reinforcement and associated finance operating and maintenance costs etc.

Question 32: I don't understand the question because the only contracts that are decoupled from output would be those that engage with plants and dispatch them without incremental remuneration, rather like the Central Electricity Generating Board. Are you really considering this? But yes, you should proceed with discussing cap (especially soft) and floor, regulated asset base (which you omit) etc.

Question 33: A hard cap (no benefit to the plant operator above the cap) would prevent markets from operating as the plant would have no incentive whatsoever to respond to market signals or need. And a hard cap would therefore return little or nothing to the system / customer.

The softer the cap (i.e. the greater the proportion of incremental revenues that the plant retains), the more responsive each plant will be to market needs / signals. At maybe (to be calculated or tested in the market), ⅓ repaid to the system, ⅔ retained by the supplier, payments returned to the customer / system are maximised because there is substantial incentive for the plant to respond to market signals while also there is generous provision for payments to customers / system. If the cap gets even softer, the direct payments to the customer / system will drop but the indirect benefits to the consumer grow as market signals are responded to ever more assiduously.

Question 34: Any system will always be gamed: trying to eliminate that is a fool's game. However it is correct to minimise the opportunities and incentives to do so. And minimising these would entail developing a system such as outlined in Question 13 above and other parts of this response.

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and connecting balancing and stability services; plus operation and maintenance = 10% of capex p.a.; all this increasing for later years

Chapter 7. Flexibility

Challenges and opportunities of the status quo; Approach to Flexibility

Please stop thinking that the status quo is anything good or desirable:

- Little or no large-scale investment has occurred since privatisation that was not planned pre-privatisation, other than under special financial instruments e.g. CfDs, ROCs, OFTOs, CATOs, Regulated Asset Base, bilateral contracts, cap-and-floor etc.
- In that time the system has deteriorated from:
  - One of the continent's most reliable to one of its less reliable systems;
  - The continent's second cheapest energy to one of its most expensive;
  - Capacity of 20-30% above peak winter demand to having to import for actual demand (since 2019), and current forecasts are for 10-hour Loss of Load Expectation next winter[94];
  - Non-energy costs (operational and network costs) rising from 20-25% of electricity prices to 75-80% of final bills.
- Costs are out of control, and the system has frequent near-misses of widespread blackouts.

As stated so many times since BEIS, Ofgem and National Grid started mis-representing the Imperial College report that asked you to stop talking about storage and start talking about flexibility and duration (the mis-representation is avoiding those last two words), flexibility without duration is meaningless. What good is 1GW flexibility with a half- or one-hour duration for keeping the lights on during an evening peak and overnight? Yet that is what this obsessive mis-representation has got us.

And energy without dispatchability or stability cannot keep the grid operating. Separating energy from dispatchability and stability requires not only contracting for each separately, but also building more grid capability to connect them, and procuring other services to provide for the instability and inadequacy between the energy input and the input of stability and balancing services.

And here you are harping on about locational signals yet again. The only advocates of these are yourselves, a few academics and a very few businesses whose technology can be implemented anywhere and whose business models game the locational incentives system. Moreover, investment even in those last would be stopped when they realise that a plant built in a given location because it's encouraged by locational pricing now may yet be rendered uneconomic by future changes in locational pricing as investment is made into the network.

[94] https://www.current-news.co.uk/news/current-price-watch-low-import-available-could-lead-to-10hr-lole-over-winter, cited previously

Options Assessment Summary

See Challenges and opportunities of the status quo, Options assessment summary in Chapter 6.

Question 35: No, all the credible options are not being considered. The most credible is the wholesale market reforms outlined in Question 13 and elsewhere in this paper. Regulated Asset Base is omitted entirely, as is a system of bilateral contracts. There is no integration of energy with non-energy operation, of the various non-energy contracts, or of any of these with network.

Question 36: Yes, reformed markets can deliver outstandingly well-designed operational signals, investment etc. – but only if long-term, integrated and with sufficient lead times; see response to Q13 and the rest of this document. It is also the only technology agnostic way of proceeding that will yield an affordable, reliable and resilient system.

Revenue (Cap and) Floor

Please see my comments on the previous chapter, Challenges and opportunities of the status quo, Options assessment summary.

Question 37: Yes, as second best only to wholesale market reform as outlined in my response to Q13 and elsewhere throughout this document, a cap and floor arrangement is the next best way to go because it does not differentiate whether the revenues derive from trading energy (very broad-brush, about one-quarter of the excess costs of the energy transition), other grid operation services (another quarter) or network benefits (a half). Therefore the remuneration method gives the plants the flexibility to benefit each of them.

Question 38:
Considerations on the hardness of the cap.
If the cap is hard (signing over all profits above the cap), then market mechanisms are destroyed and market signals will not be followed as companies approach their cap. And this ceiling on incentive to respond to the markets will ensure that no (or minimal) repayments to consumers are made under the regime.

If the cap is soft (the company retains a proportion of the profits above the cap, paying the rest to the system / consumers), then some incentives remain for the company to respond to market signals and deliver market needs: the softer the cap (the more profits are retained by the company), the more assiduously they will respond to market needs. If maximising payments to the system / consumers is the objective (and this is a narrow objective, as opposed to total system costs, operability, reliability and resilience), then this will probably be achieved at about ⅔ retained by the company and ⅓ paid out under the cap.

If there is no cap, market signals are maximised and consumers benefit indirectly much more than by the total of any refunds from a soft or hard cap. These indirect benefits

are system costs, operability, reliability and resilience etc. Therefore the consumer / system benefits most by the elimination of any cap. For example, if caps are set in anticipation of energy trading, there is no incentive to support system operability contracts or network cost reduction/avoidance; if set to include system operability, there is no incentive to reduce/avoid network costs; if there is no cap, then there is incentive to maximise benefits to the system as a whole.

Considerations on the floor.
The larger-scale the asset is, the costlier it is. Ditto if duration is longer. Ditto if it's more capable, e.g. addressing system operability issues (the more issues, the costlier) and network cost avoidance / operability issues (again, the more issues, the costlier).

Costs also increase with the grid voltage level to which the asset is connected. But so do benefits: each distributed system depends on the level above, and ultimately the transmission grid, for back-up, regulation, control and support. Therefore remuneration should be higher for higher-voltage assets, and floors set correspondingly.

Therefore the floor should be calculated based on the range of whole-system benefits that the development targets.

Question 39: If the mechanism is designed as outlined in my answers to Q37 and Q38, then it is technology agnostic and allows all technologies to compete on an equal footing based on the capabilities of each technology and asset.

Options for reforming the Capacity Market

As stated above, the Capacity Market is for energy only. As previously stated (Central contracts with payment decoupled from output), outputs need to be defined not just as energy but also as:

1. Dispatchability (balancing services, arbitrage etc.)
2. Duration
3. Speed of response (ancillary services)
4. System operability (voltage and frequency control, reactive power/load etc.)
5. System stability (real inertia, leakage currents etc.)
6. Resilience (various restoration services, e.g. as tendered by DNOs)
7. Black Start
8. Constraint alleviation
9. Alleviation of other network costs such as curtailment, grid reinforcement and associated finance operating and maintenance costs etc.

Unless the Capacity Market were to reward future capacity in all of these, especially the first six with life-of-plant contracts for 7-9 (because they involve either building capability that can't then be un-built [7-9] and/or avoiding costs in ways that can't later be removed from the system [8, 9]), then they are un-suited to the whole market, but only to asynchronous intermittent generation (solar and wind).

Question 40: As a second-best option to whole-system market reforms as outlined in my answer to Q13 and elsewhere in this consultation response, the Capacity Market with multipliers for all the 9 aspects above (or for the first six, combined with life-of-plant contracts for 7-9) is a worthwhile second-best to wholesale market reforms and re-design as per my responses to Q13 and elsewhere in this consultation response.

Please note that further reforms to the Capacity Market are **also** needed in order for it to deliver its aims:

1. T-4 contracts only being biddable by new plants or major re-powering of plants; otherwise it's just a second bite of the T-1 cherry that fails to ensure that new capability is being built to replace aging assets.
2. T-4 becomes a flexible lead time that allows for new assets to be built and connected to the grid, including permitting, design, construction and commissioning time;
   - Alternatively, T-4 could be awarded with a guarantee of building the grid connection within the 4 years; in which case, for some plants (e.g. CAES, pumped hydro, offshore wind) the 4-year lead time is to start of delivery with capacity ramping up over the following years.

Question 41: The characteristics that should be valued within a reformed Capacity Market should not just be "flexibility enhancements", but should cover:

1. Dispatchability (balancing services, arbitrage etc.)
2. Duration
3. Speed of response (ancillary services)
4. System operability (voltage and frequency control, reactive power/load etc.)
5. System stability (real inertia, leakage currents etc.)
6. Resilience (various restoration services, e.g. as tendered by DNOs)
7. Black Start
8. Constraint alleviation
9. Alleviation of other network costs such as curtailment, grid reinforcement and associated finance operating and maintenance costs etc.

Unless the Capacity Market were to reward future capacity in all of these, especially the first six with life-of-plant contracts for 7-9 (because they involve either building capability that can't then be un-built [7-9] and/or avoiding costs in ways that can't later be removed from the system [8, 9]), then they are un-suited to the whole market, but only to asynchronous intermittent generation (solar and wind).

Supplier obligation

Question 42: A supplier obligation is a wholly bad idea. Suppliers have a narrow, partial and short-sighted view of system / market needs, so these shortcomings would be reflected in their approach. The only way to overcome it is nationalisation and integration, or sufficiently onerous legislative knots to provide a semblance of that despite its destruction of economic incentive for the suppliers. For further details, please see my answers to questions 26-28.

Question 43: Yet again, flexibility without duration is meaningless. And flexibility only addresses one-quarter of the issue, another quarter being non-energy system operability services and fully a half being the network. So a supplier responsibility to provide flexibility would merely undermine the revenue stacks of those systems that offer the other things too, driving up prices as the better systems would have to increase prices to compensate for the lost parts of the revenue stack.

Question 44: Clean Peak Standards appear to be a very costly and bureaucratically onerous way of getting others to do what is in truth the grid operator’s responsibility. Why can’t the grid operator deliver on its responsibility instead of shirking it, and procure sufficient flexibility, system operability services and also network cost reduction services, instead of trying to blame and penalise everyone else with obligations and standards that cause all manner of additional administrative and financial burden? Such obligations and standards distort the markets; the grid should be enhancing the market instead.

The list of multipliers is inadequate as they omit the majority of the issues confronting the grid as it decarbonises.

Chapter 8. Capacity Adequacy

Challenges and opportunities of the status quo

I am pleased that at last BEIS, Ofgem and National Grid are coming round to understanding that we can’t rely on imports through interconnectors for either actual demand or our supply margin, as I have been saying since 2016, and quantified in 2018[95]. Indeed, recently the expected Loss of Load Expectation for the winter 2022-23 has been calculated at over 10 hours[96]: “*This is in large part because the ESO’s outlook did not include the “very possible scenario” that Britain won’t receive imports through its interconnectors from Europe.*” Such a scenario is exactly what I’ve been outlining these past six years: “times of system stress” such as after sunset on a windless winter evening very often occur concurrently across the continent.

And it will get worse. We’re still in late summer, temperatures have hardly started to drop. Yet we can only keep our lights on by running four coal-fired power stations and all the gas ones, all of which are scheduled to close. And the continent is in the same position. As almost every European country plans by 2040 to import during times of system stress (many countries are in that position already, and many more will be by 2030), the problem is critical.

The lead time of every single large-scale long-duration electricity storage technology is 7-10 years. This makes it utterly critical to start a massive construction programme

[95] https://www.storelectric.com/interconnectors-and-imports/, cited previously
[96] https://www.current-news.co.uk/news/current-price-watch-low-import-available-could-lead-to-10hr-lole-over-winter, cited previously

immediately. Unless the market is sorted out as outlined in my response to Q13 and elsewhere in this response, or (failing that) comprehensive revenue (soft cap and) floor mechanisms are put in place immediately, then the government will have to subsidise it.

And that doesn't just apply to proven technologies such as pumped hydro. Less-proven technologies such as CAES and (where CAES is not possible) LAES (as it's much dearer and less efficient than adiabatic CAES) should be incentivised with help for first-of-a-kind commercial plants.

One final piece of advice on this: owners of suitable locations are very uninterested in supporting these technologies. Ways must be found to either compel or incentivise them (or a combination of the two) to support them by making their locations available, both practically and economically.

Options Assessment Summary

Question 45: These are all suitable options to address longer-term capacity issues, but must not be restricted to energy alone for all the reasons outlined elsewhere in this response. The principal option that is not considered is a proper complete reform of the energy markets such as outlined in my answer to Q13 and elsewhere in this document.

A strategic reserve is an excellent complement to such a market. The government is aware that renewables vary naturally in output year-on-year by as much as 17%. The strategic reserve must accommodate that variation, plus the supply margin of 10-15%. Therefore 25-30% more capacity is needed than will be used normally, which must be procured as reserve. But it mustn't just be for energy, but also for system operability capabilities and network optimisation/operability too.

Grouping options, Optimised Capacity Market

Question 46: If you don't introduce true and full market overhaul along the lines described in my answer to Q13 and throughout this consultation response, then yes, reform the capacity market. But don't oo it half-heartedly or partially. A Capacity Market is only suitable for wind and solar (intermittent, asynchronous) unless it's expanded with multipliers for all the system operability and grid optimisation / operability capabilities that a plant has; if it has all such multipliers, it stands a chance.

Yet again, no system operability issues or network optimisation / operability issues. This is truly tunnel vision.

Once again, nothing to do with length of contract / need; long contracts are needed to incentivise major new build. Nor is there any reflection of lead time issues: it is impossible to get a new transmission grid connection within the lead time even of the T-4 Capacity Market. This is truly short-sighted.

It is only suitable for larger-scale, longer-duration, dispatchable plant if the lead times are long enough to allow grid connection as well as design, funding and permitting.

And it will always be subverted from its aim of encouraging construction of new plant for as long as (a) existing plant can bid, and (b) plants can bid for contracts below the contract period of the auction, e.g. 1-year bids in the 15-year T-4 auctions.

I don't know why this entire chapter, and the last, are largely reiterations of previous chapters.

Question 47: Regarding separate auctions, see Splitting the Market, above. However there is benefit by splitting contracts into short-, medium and long-duration, with about one-third of procured capability in each; only new plants being allowed long-duration contracts; new, heavily invested and deeply refurbished plants could bid for medium-duration, and anyone can bid for short. Further details have been discussed[97].

Carbon needs to be in the same market as low and zero carbon, but disincentivised by a proper carbon price. If the national carbon price remains too low (currently less than one-tenth of the societal cost of emissions), then a proper carbon price (at the societal cost of carbon) should be imputed to each plant, based on the carbon emissions generated by that plant (i.e. for energy storage, ignoring any carbon content of purchased electricity). Interconnectors operate as part of the grid, so they would incur carbon charges/costs depending on the source of the electricity they carry.

Multiple clearing prices have all the hazards described in Splitting Markets above, which are much greater than the few benefits.

Question 48: No, the CM optimisation envisaged will not ensure capacity adequacy in future – see my answer to Q46.

Question 49: Yes:
1. Implement the comprehensive market reforms identified in my answer to Q13 and throughout this response.
2. Implement a reserve market of some form, whether Capacity Market or otherwise, for an additional 25-30% of capacity to be held in reserve: not just in energy but also in system and network operability and optimisation.
3. Get building many GW of large-scale long-duration storage **NOW**: we're already going to be short of electricity this coming winter, the issue is only going to get worse as old power stations are pensioned off, and such storage (of all technologies) has 7-10 year minimum lead times.

Strategic Reserve
The consultation document is still repeating previous points. See my response to Q45.

97 https://www.storelectric.com/21st-century-electricity-system/, cited previously

Question 50: Yes, there needs to be a strategic reserve that accounts for both the 10-15% supply margin and the up-to-17% year-on-year fluctuation in renewable generation. How this is done is debateable: plants could be financed to be held in reserve or, better, plants provided with an availability payment large enough to cover their costs while the use of those plants is cycled around them in order to ensure that their stores are refreshed periodically and their machines turned, to keep them in good operating order. The cycling of those plants will be based partly on pure cycling, and partly on the comparative economics and technical capabilities of each plant.

Question 51: First and foremost, a comprehensively reformed market (outlined in my response to Q13 and above) is needed to work alongside a strategic reserve. If such a market is not implemented, then a comprehensive revenue (soft cap and) floor mechanism is needed that covers all energy and system / network operability / optimisation contracts and capabilities. And these can best operate in single, integrated markets with carbon prices (actual or imputed) that reflect the societal cost of emissions.

Question 52: Yes, the government could own the strategic reserve if it's kept as a reserve. But this would not be the best method: it would have to operate partly-competitively in the markets for the element that covers the 17% year-on-year fluctuations in renewable generation, and would not be able to be cycled in the way I outline in my response to Q50. On the other hand, the government could fund the availability aspects of not only the reserve but also the operational storage, so that all together can be {operational + reserve}, cycled regularly.

Centralised Reliability Options

Question 53: No. Unless the operating costs of storage / reserve are covered, Centralised Reliability Options will not work: they must cover their costs even when the options are not exercised, or they'll go bankrupt; certainly no investor would invest in such a plant. The proposal envisages them operating only in scarcity: how else will they be kept viable in the meantime to be available during times of scarcity? How else would storage pay up-front for the energy it stores, and ongoing to keep it refreshed (e.g. thermal losses)? It doesn't matter how ingenious your ideas are for not paying for what you're not using, they'll always come back to the same challenges: who would invest in plant that is not earning its keep, and how would it stay open and available while not being used? This brings us back to an availability + utilisation contract.

Question 54: See response to Q53.

Question 55: See response to Q53.

Decentralised Reliability Options / Obligations

Question 56: I agree that you should cease consideration of decentralised reliability options / obligations. They are much worse than centralised ones. All distributed systems rely on the grid for back-up, as it's totally inefficient and un-economic to provide such capability in distributed manner: this, after all, was why the grid was built

in the first place, 70 years ago. Do we want to go back to the Victorian age when every town looked after itself and suffered frequent black-outs when one of their few plants has problems? Those black-outs didn't matter much then, because few were dependent on the grid; now it pervades almost every aspect of our lives and is critical.

Question 57: No, I see no benefits from decentralised reliability options / obligations that can be taken forward into other market arrangements.

Capacity Payment

Question 58: Yes, there needs to be a capacity payment. This is likely to be the availability part of availability + utilisation contracts. And it should not only cover energy, but also have multipliers for all system / network operability / optimisation capabilities. And the overall capacity / availability payment must suffice to pay for plants to be kept in reserve, and then cycled with the plants that are operated more heavily.

Targeted Tender / Targeted Capacity Payment

Question 59: Given that the government has been flagging the need for up to 59.2GW new 5-hour storage for a decade, in which time none has been built, contracted or started, there is a need for targeted tenders and capacity payments – at least until sufficient is built or under way. Once that is achieved, a full market reform along the lines of my response to Q13 and elsewhere in this document will suffice; failing that, i.e. under any other arrangements the requirement for targeted tenders and capacity payments will remain.

Question 60: Targeted tenders and capacity payments are a good, proportionate response to the urgent and unsupplied needs of the system. The risk of over-compensation is negligible: (a) reserve capacity of 25-30% above peak demand is needed; (b) demand is growing fast (and will be faster than National Grid forecasts[98]), so even if excess capacity were to be built, it would soon be required; and (c) we are so far behind in building what is needed.

Chapter 9. Operability

Challenges and opportunities of the status quo

The status quo is not sustainable in any way. National Grid is intent on ignoring the difference between real and synthetic inertia (real is good for preventing faults, synthetic for recovering from them[99]) just as for the last 6 years or more it's been intent on ignoring the fact that we can't rely on interconnectors. It remains equally intent on

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[98] https://www.storelectric.com/analysis-of-national-grid-future-energy-scenarios-2022-summary-of-findings/ for summary and https://www.storelectric.com/wp-content/uploads/2022/07/Analysis-of-National-Grid-Future-Energy-Scenarios-2022.pdf for detailed analysis
[99] https://www.storelectric.com/wp-content/uploads/2020/02/Lessons-for-Europe-from-the-UK-blackouts-v2.pdf

ignoring the needs to integrate capabilities, and to provide sufficient capability on the transmission grid to provide back-up in times of system stress. The current situation is increasingly unaffordable, unreliable and fragile, and getting more so exponentially[100].

Question 61: Continuing the status quo and incremental modifications are not credible options, owing to the gravity of the current situation and the bad direction in which we're headed.

Developing local markets etc. is not tenable either, above a certain threshold (to be calculated): all distributed systems rely on higher-voltage grids for back-up. Therefore there needs to be sufficient capability on the higher-voltage grids, especially the transmission grid, to provide that back-up. These need a revenue stack to be profitable. Once distributed systems encroach on that revenue stack, they'll have to put up their prices to compensate; therefore any such encroachment merely adds cost without adding capability.

Regarding the changes to CfD, CM and wholesale markets, see above: what is envisaged is totally inadequate, short-sighted and narrow in scope. What is needed is comprehensively reformed, integrated markets (i.e. integrating energy, system and network operability/optimisation) with long-duration contracts intrinsic within the system, and long lead times where needed, as described in my response to Q13 and elsewhere in this document.

Enhanced existing policies

Question 63: Giving the ESO or FSO an obligation to prioritise zero/low carbon procurement would be good. However unless they can integrate considerations of energy, system operability and network, they cannot do a thorough job on it. Giving them responsibility to prioritise low carbon ancillary services is a start (though there must be integrated consideration of them with each other and with other aspects), but together with energy they form less than half of the challenge; network costs and optimisation form most of the rest, and there are many interplays between these, energy and system operability so the three should not be considered separately from each other.

"*Ensuring the ESO strikes the optimal balance between long and short-term contracts for ancillary services…*" is excellent, and in line with the proposals in my response to Q13 and elsewhere in this response document. Such balance should be struck in energy services procurement too; all network operability / optimisation issues are necessarily long-term.

"*Aligning Capacity Market and CfD tenders with those for ancillary services…*" goes some way towards creating the integrated markets that are needed, though not far enough.

[100] https://www.storelectric.com/challenges-of-the-electricity-transition/, cited previously

"*Introducing a matrix approach to ancillary service provision in which providers can submit linked bids for ancillary services which can only be delivered together. …*" is perfect, inasfar as it goes; it should extend to energy services and network operation / optimisation too. Bundled bids are absolutely necessary for encouraging large and broadly capable plant, and ultimately for driving down costs – especially in the medium and longer terms.

Developing local ancillary services markets

Question 64: Existing and planned coordination activity between ESOs and DNOs only tickle the edges of ensuring optimal operability. It is a necessary component, but only one of many essential and important components in doing so. And there is, as yet, no awareness that all distributed systems rely on the higher-level (and ultimately Transmission) grid for back-up, so there must be sufficient capability on the grid providing it (not just energy, but everything else too), so any encroachment by distributed systems on the revenue stacks of these grid-based systems merely adds cost without adding capability as they need to replace those lost revenues by putting up prices for other services. Once that realisation is there, they can then calculate the threshold, which may differ in various locations and will certainly vary by voltage level.

Question 65: The greater scope for distribution-level institutions lies in the integration of energy, operability and grid services and optimisation. Beyond that, there is little that they can contribute. Note that National Grid's own engineers have not found (despite intensive attempts over many years) any way for any Distributed Re-start assets to start any grid sections at higher voltage level; nor have they found a way for any DC-connected assets (even with grid-forming inverters) to re-start even wider parts of their own section of the grid[101].

Changes to CfD design to support low carbon ancillary services

Question 66: As stated above, CfDs in their current form are suited only to procuring energy, not dispatchability, stability or other forms of operability. Indeed they actively discourage doing so by capping revenues. Moreover, as CfDs are paid at grid connection, they actively penalise renewable generation for installing behind-the-meter storage: output is reduced by the inefficiency of storage, so they're paid for fewer MWh despite those MWh being much more valuable to the grid, and especially valuable if the storage is naturally inertial.

Changes to Capacity Market design to support low carbon ancillary services

Question 67: Modifying the CM design to support such services is like modifying a bicycle to provide automotive services: you just wouldn't do it as the result would be grotesquely under-performing and expensive, as well as unwieldy and ugly. You'd design a car instead. And modifying even that to provide aviation services is equally ridiculous: you'd design an aeroplane instead – as would be the analogy when grid operability and optimisation services are also added. Much better to re-start with full market reform and restructuring as outlined in my response to Q13 and elsewhere in

[101] https://www.storelectric.com/wp-content/uploads/2020/09/Re-Starting-Net-Zero-Grids-Black-Start.pdf, cited previously

this document or, failing that, to introduce either central planning and/or revenue (soft cap and) floor contracts across the market.

Co-optimisation of ancillary services

Question 68: I agree wholeheartedly that "*co-optimising between different markets could lead to a very efficient allocation of generation/demand between the wholesale market and ancillary services market.*" It would be exceedingly good to do so. It would be much better to extend this co-optimisation to cover network operability and optimisation so as to be able to avoid having to triple (or more) the size of the grid during the energy transition, as widely forecast to be necessary and as supported by National Grid's own Network Options Analysis and Pathway to 2030 – Holistic Network Design[102].

Chapter 10. Options across multiple market elements

Auction by cost of carbon abatement

Question 69: It is excellent that you are considering options across multiple market elements. I hope that your consideration is sufficiently broad.

Auction by cost of carbon abatement is starting to approach the simpler and more comprehensive method of actual or imputed carbon pricing to prices that equate with the social cost of emissions. It would be better to implement the latter system[103], better with a system of actual charging; failing that, by imputing such charges for consideration within energy system tenders and contracts. In this, there is no difference between contracts for "mass low carbon power" or "flexibility".

If considering charging for emissions, please ensure that only the emissions created by the asset are charged. For example, storage should not be penalised because the grid's input energy has embedded emissions, which are not under its control; it should only be penalised for what it adds.

It is wrong that "*flexible assets … should only be incentivised to generate or reduce demand when there is a deficit of renewable (and nuclear) generation …*" as a large part of their value lies in remaining available when not used. And this is greatly increased when reserve capability is considered. It is folly to think that if the system only pays an asset's costs when it's used, then doesn't use it all the time, that that asset will remain available when next needed: it is likely to be bankrupted by the wait, and new capacity will not be built due to extreme revenue uncertainty.

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102 https://www.storelectric.com/pathway-to-2030-holistic-network-design/
103 https://www.storelectric.com/incentivising-clean-energy/, cited previously

It is bizarre that you're concerned by a lack of payback mechanism in certain market offerings: if it's a market, then assets must be able to earn high profits as easily as to earn inadequate ones, it can't be a one-way (downwards) bet. Nobody would invest in that. A market should be swings and roundabouts, not only roundabouts.

Question 70: As question 69.

Question 71: For many carbon abatement charges, there are huge unknowns, such as how many trees one needs to plant, for how long one must guarantee they remain untouched, how to guarantee that rainforest felling is not merely displaced, the cost and feasibility of CCS. These are all much too imponderable. Much better to apply the (much higher) societal cost of emissions[104].

Question 72: The Dutch scheme is an excellent attempt to incorporate the negatives of emitting technologies and the positives of zero- or low-emissions technologies within the operation of markets and contracts. The fact that it doesn't go far enough should not deter the UK from seeking better mechanisms to achieve such results.

Equivalent Firm Power Auction

Question 73: Intermittent generation cannot provide equivalent firm power. Therefore there should be no imputation of such a concept on such generation in any way, shape or form. Already future scenarios are drawn into far too many errors by using statistical average output, even if varied by actual meteorological data – hence the expected >10-hour loss of load expectation this coming winter[105], "*in large part because the ESO's outlook did not include the "very possible scenario" that Britain won't receive imports through its interconnectors from Europe.*" Apart from for the short term (up to 2-5 years hence), dispatch models (which are based on a myriad of such assumptions) are highly deceptive and therefore worse than useless in predicting need. Much better to use much simpler yet more rigorous analyses such as this one for calculating the need for storage[106].

Moreover, there are two types of firm power: baseload and dispatchable. They do very different jobs: baseload provides for baseload demand whereas dispatchable provides for both variable demand and intermittent generation. The values of each differ, and should be evaluated differently. Incidentally, the value of baseload generation is much greater than is normally considered: to provide 1GW baseload demand, one would require 1GW nuclear or (these are rough figures) 3GW offshore wind plus storage, or 4GW onshore wind plus storage, or 8GW solar plus storage (to allow for the losses of storage). And all that storage would have to be not only a scale comparable with that of the renewable generation, but also very long duration (2 weeks).

[104] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/, cited previously
[105] https://www.current-news.co.uk/news/current-price-watch-low-import-available-could-lead-to-10hr-lole-over-winter, cited previously
[106] https://www.storelectric.com/calculating-the-need-for-storage/, cited previously

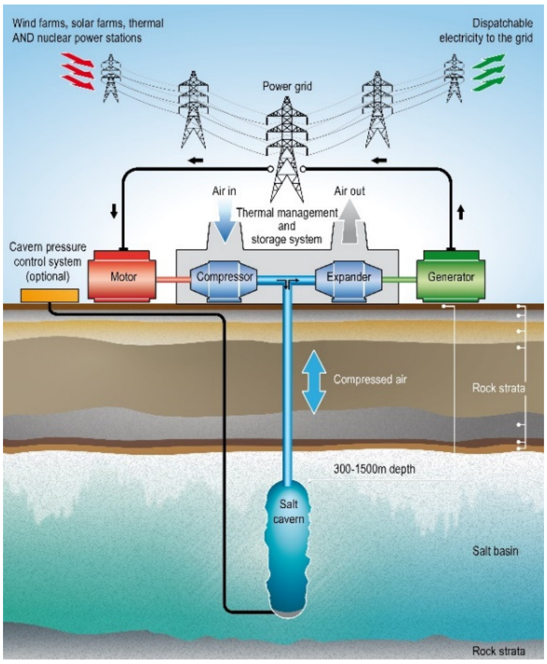
Question 74: There is no way in which the challenges identified with the Equivalent Firm Power auction can be overcome. It's a thoroughly bad idea.

Mark's Blog

Personal blog of Mark Howitt, founding director and CTO of Storelectric Ltd and recognised international expert in the energy transition

About Storelectric

Storelectric (www.storelectric.com) is developing transmission and distribution grid-scale energy storage to enable renewables to power grids reliably and cost-effectively: the world's most cost-effective and widely implementable large-scale energy storage technology, turning locally generated renewable energy into dispatchable electricity, ***enabling renewables to power grids cheaply, efficiently, reliably and resiliently***.



- Innovative adiabatic Compressed Air Energy Storage (Green CAES) will have zero / low emissions, operate at 68-70% round trip efficiency, levelised cost significantly below that of gas-fired peaking plants, and use existing, off-the-shelf equipment.
- Hydrogen CAES technology converts & gives new economic life to gas-fired power stations, reducing emissions and adding storage revenues; hydrogen compatible.
- Storelectric has also patented the use of the heat of compression to catalyse electrolysis, for efficiency and scalability.

Both CAES technologies will operate at scales of 20MW to multi-GW and durations from 4 hours to multi-day, more cost-effective and configurable than any other technology to suit a vast range of applications / use cases, concurrently delivering grid stability based on real inertia. With the potential to store the entire continent's energy requirements for over a week, global potential is greater still. In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES, all of which will greatly improve storage cost, duration, efficiency and global potential.

About the Author

Mark Howitt is Chief Technical Officer, a founding director of Storelectric. He is also a United Nations (UNECE) expert advisor in energy transition technologies, economics, regulation and politics – invitation here. He is also a member of the UK advisory team to the IEA (International Energy Agency), member of the Energy Storage Steering Group of the Renewable Energy Association, frequent consultee to the British energy ministry, regulator and National Grid, and expert speaker at many conferences.

A graduate in Physics with Electronics, he has 12 years' management and innovation consultancy experience world-wide. In a rail multinational, Mark transformed processes and developed 3 profitable and successful businesses: in commercialising a non-destructive technology he had innovated, in logistics (innovating services) and in equipment overhaul. In electronics manufacturing, he developed and introduced to the markets 5 product ranges and helped 2 businesses expand into new markets.

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