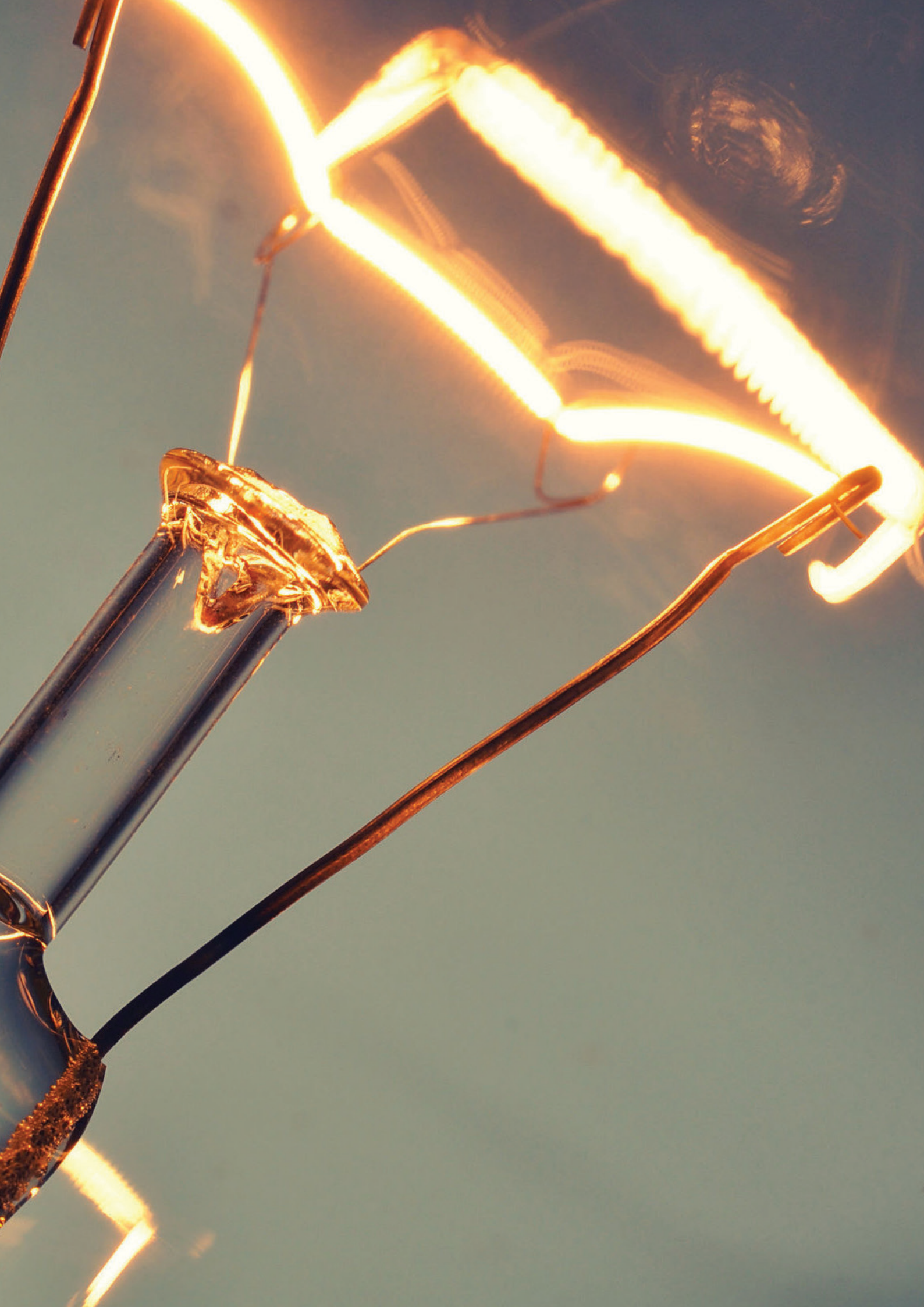
ADDLESHAW GODDARD

October 2018

ENERGY MARKET DISRUPTION SUPPLEMENT

Articles from the Addleshaw Goddard Energy & Utilities Group



CONTENTS

23 July 2018

GETTING MORE OUT OF OUR ELECTRICITY NETWORKS

Recently, Ofgem put forward proposals to reform the way that generators and users of electricity get access to, and are charged for using, the electricity network.

The consultation, Getting more out of our electricity networks by reforming access and forward-looking charging arrangements, has just closed and Ofgem will decide before the end of this year whether to issue a Significant Code Review to take the reforms forward.

Context

New technology such as electric vehicles, storage and heat pumps will mean we will need more electricity in the future. The existing infrastructure cannot cope, and in some areas is already overloaded. It costs a lot of money to upgrade; costs which are passed onto consumers through their bills. Ofgem regulates what the network companies can spend on infrastructure upgrades and is currently looking at the next round of price controls, known as RIIO-2. These are likely to be tougher – see our article, **RIIO-2 Framework Published**, for background.

So instead of upgrading the network, Ofgem has for a while now been looking at how to make better use of it. See for example the **Smart Systems and Flexibility Plan** and the Targeted Charging Review of residual network charges (our article **Ofgem Minded to Cut Embedded Benefits** provides helpful context for this).

The latest consultation looks at the charges for accessing and for using the electricity transmission and distribution networks.

Access arrangements

These set out how users access the electricity networks: how much they can import or export, when and for how long, where to/from, and how likely their access is to be interrupted and what happens if it is.

The problem is that some areas are congested because there is too much generation connected to the network whilst in other areas there is pressure on the network caused by increasing demand. At the moment there are limited ways of rewarding those who can be flexible, or of encouraging new generation to connect to the network in areas that are not congested.

Ofgem are thinking about introducing a "core" level of access for small users (including households with an electric vehicle), with options to obtain additional different types of access above this. For larger users, Ofgem want to improve the definition and choice of firmness (in other words, how much the connection can be interrupted) and time-profiled access rights; and are asking if they should give more choice of duration and depth (geographical extent) of access rights.

Another option, either Ofgem-led or industry-led, is to set up mechanisms to enable trading and exchange of access rights; and introduce "use it or lose it" conditions. Giving more choice of time-profiled access rights would support more of a capacity-based charging approach (e.g. off peak access would have lower capacity charges), to incentivise users to release spare capacity at times when they are not using it.

Forward looking charges

These include the upfront connection costs for connecting to the system and the ongoing forward-looking use-of-system charges.

Ofgem are proposing:

- a comprehensive review of forward-looking DUoS (Distribution Use of System) charges: improving the granularity and predictability of locational signals and also considering the balance between usage-based and capacity-based charges;
- a review of the distribution connection charging boundary: whether to move to a shallow connection charging boundary at distribution (where the connection customer only pays for their own sole-use connection assets, which is how the transmission connection boundary works) as opposed to the current shallow-ish connection boundary (where in addition to their own sole-use connection assets the connecting customer also contributes to wider network reinforcement); and whether to introduce user commitment requirements at distribution level; and
- a more focused review of forward-looking TNUoS (Transmission Network Use of System) charges: aligning how distribution and transmission generation users are charged for their impact on the transmission network, and whether to review the charging of demand under TNUoS.

Examples

All this is technical stuff so, thankfully, Ofgem have included some case studies showing how the reforms could affect three different types of network user.

Large solar generator

A solar generator wants to connect to the distribution network and export electricity in an area that already has lots of generation and, as a result, network constraints. The local DNO has to curtail generation output at certain times and the distributed network frequently exports power onto the transmission network.

Currently, the DNO could offer either a "standard" connection, where the generator has a low chance of being curtailed but has to pay network reinforcement costs, or a "flexible" connection, where they pay no reinforcement costs but have to accept being curtailed with no cap on this.

The curtailed model throws up some obvious challenges from a funding perspective. To attempt to address those, the reforms could include a cap on the amount of curtailment generators can face, or make curtailment time-limited. They could also bid to not be curtailed, with other generators or users (such as demand side response providers) being able to offer in services to help manage the constraints.

Commercial customer with onsite generation

A large demand user with the ability to participate in demand side response wants to connect to the extra high voltage (EHV) distribution network. It also has an onsite generator, which can meet most of its demand. It does not export onto the network.

Currently it has no choice of its access option: if the connection requires reinforcement, then the customer has to pay the full cost of this.

The reforms could mean:

- they could choose a time-profiled access right, and get a discount on their UoS charge, and use their onsite generation at other times; or a cheaper non-firm access right, using their onsite generation when the connection is curtailed
- changing the connection boundary so that their connection charge only covers sole-use assets not wider reinforcement (aligning the distribution connection boundary with how the transmission connection boundary works).

Domestic user installing an EV connection

A domestic household with a smart meter wants to install a home EV charging point.

Currently, the customer would not pay any extra charges for this even if the network needed reinforcing as a result of the increased demand. There is no incentive/disincentive to charge at peak times or to use a slow rather than a fast charger.

The reforms could mean households are charged less if they opt for slow charging over fast charging, or only charge off-peak, or have their charging managed by their DNO. On the flip side, there could be higher charges for uninterruptible charging at peak times.

What's next?

Ofgem will decide by the end of 2018 whether to launch a Significant Code Review (SCR) to take these reforms forward. If they do, then the SCR will conclude in late 2020 and there will be a Direction to licensees to develop Code modifications (the relevant codes here being the DCUSA and the CUSC) to implement the reforms. The scope of the SCR is still to be decided; those aspects that Ofgem decide are out of scope will be left to the industry to take forward, and could actually happen more quickly than those that end up part of the SCR process. The first set of SCR reforms should be in place by April 2022, the rest in April 2023.

Comment

These are exciting reforms as they will, if and when they go ahead, mean more choice for generators of how they connect to the network and more rewards for using the network flexibly. Gone are the days when everyone needed a constant supply of power, but the network charges are still based on this. These proposed reforms should mean those who can ramp their power use up and down as needed, to even out constraints on the network, can be appropriately rewarded. At the same time, this flexibility would bring a new level of complexity to these types of projects which might be a challenge for some funders and potentially unattractive to potential acquirers. That might limit the possibilities for certain project developers to take advantage of the full range of flexible options.

Contacts

Paul Dight

Richard Goodfellow

Paul Minto

26 July 2018

NATIONAL INFRASTRUCTURE ASSESSMENT – ENERGY IMPLICATIONS

On 10 July 2018 the UK's National Infrastructure Commission (NIC) published its National Infrastructure Assessment (NIA).

This, the first of what will be five-yearly NIAs, sets out the NIC's plan of action for the UK's infrastructure over the next 10-30 years. It covers energy, transport, water and waste water, flood resilience, digital connectivity, and solid waste. Its recommendations are a list of fully costed projects, not an unaffordable wish list.

Our overall impression of the NIA is that it is a holistic view of infrastructure, not looking at different sectors in isolation but acknowledging that they overlap. For example it considers the impact of the increased use of electric vehicles on the energy sector as well as transport, and it recommends mandating the collection of food waste by local authorities to fuel biogas plants for use as a heat and transport fuel.

Having said that, it is worth a look at the report from an energy sector perspective.

Renewables or nuclear…or both?

The press immediately picked up on the recommendation that the government should not agree support for more than one nuclear power station beyond Hinkley Point C before 2025. Together with the recommendation that at least 50% of our electricity should come from renewables by 2030, they proclaimed that "Britain's nuclear ambition must make way for renewable energy", according to The Telegraph. But the reality is not as clear cut. The NIA actually says that its modelling shows that delivering a low carbon electricity system for 2050 powered mainly by renewables is a low cost option, cost comparable to building further nuclear plants after Hinkley Point C. So it is not ruling out nuclear, but saying that renewables could be a viable alternative. It does however acknowledge that no country has yet built an electricity system with very high levels of variable renewables so there is still a large amount of uncertainty. It recommends a 'one by one' approach to new nuclear plants, which will allow the UK to pursue a high renewables mix without closing off the nuclear alternative.

Of course, the reality is that there will not be support for more than one new nuclear power station before 2025 anyway, given the long lead times involved.

To achieve a 50% renewables mix by 2030, the NIC favours using the existing Contracts for Difference mechanism, rather than reinventing the wheel, but revising which technologies are in which pots and reinstating a pipeline of pot 1 auctions. So offshore wind, which is now cost competitive, should be moved to pot 1 after the forthcoming pot 2 auction in spring 2019 and then there should be a pipeline of pot 1 auctions and possibly a small-scale pot 2 auction in the 2020s.

The NIC also recommends that whole systems costs should be taken into account in the strike price as far as possible, but this formula will need to be developed over time as it is very complicated to work out.

The heat is on

Decarbonising heat is the next big challenge. At the moment, 69% of heat is produced by burning natural gas. This must be radically reduced if the UK is to meet its Climate Change Act legal targets. The NIC boils it down to a choice of two routes: hydrogen or electrification. We need to decide which route to take by the 2020s: should the gas network be maintained and converted to hydrogen, or phased out?

So that the government can make an informed choice, the NIC recommend:

- Establishing the safety case for using hydrogen as a replacement for natural gas, followed by trialling hydrogen at a community scale by 2021
- Subject to the success of community trials, launching a trial to supply hydrogen to at least 10,000 homes by 2023, including hydrogen production with carbon capture and storage
- By 2021, the government should establish an up to date evidence base on the performance of heat pumps within the UK building stock and the scope for future reductions in installation costs

Whether the government is prepared to make such a bold decision in the near future remains to be seen and we think it likely that they will continue to pursue both options for as long as possible. For background on the hydrogen option see our article **Hydrogen: more than just hot air?**

What we do know is that both options involve energy efficiency improvements in the short term. The NIC recommend a target of installing 21,000 energy efficiency measures in buildings a week by 2020. The Government's response to the recent ECO3 consultation (see our article **Energy efficiency: the future of the Energy Company Obligation (ECO3)**) does not go this far, so the industry will need to step up without relying on Government support.

Britain's nuclear ambition must make way for renewable energy

TELEGRAPH

CCS is not an option... unless for hydrogen

The Commission's modelling shows that continuing to use fossil fuels with the addition of carbon capture and storage (CCS, also known as carbon capture, use and storage - CCUS) is unlikely to form part of a cost competitive generation mix. So it is not recommending that government subsidise CCS for power generation but it acknowledges that CCS will not be built without government support.

But that does not mean the end for CCS. The most pressing reason to develop it at scale is likely to be for the manufacture of low carbon hydrogen, should the government go down the hydrogen for heat route outlined above. The CCUS Cost Challenge Taskforce Report published on 19 July acknowledges the role of CCUS for hydrogen production but believes it has a much wider role. It will be interesting to see the government's response to both these reports.

Comment

The NIA has made some bold recommendations and the government will need to make some brave policy choices if it chooses to follow those recommendations.
We await the government's response but, given the current preoccupation with Brexit, we suspect that the government will keep its options open for as long as possible and continue the current path of supporting both renewables (to a limited extent) and nuclear; hydrogen and heat pumps; and CCUS as far as it can, but with as much risk on the private sector as possible.

30 July 2018

THE ROAD TO EVS

Recent policies from the UK Government show they are committed to promoting the take-up of electric vehicles.

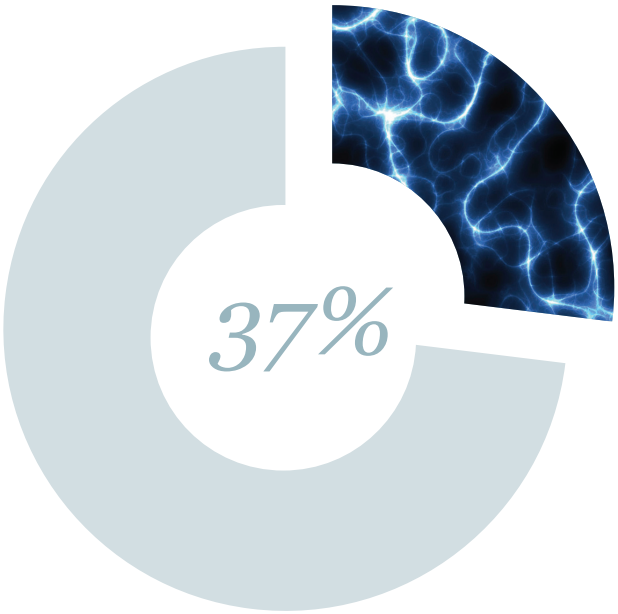
First there was the Road to Zero on 9 July 2018, the Government's next steps towards cleaner road transport and delivering the Industrial Strategy. This was followed the very next day by the National Infrastructure Commission's National Infrastructure Assessment (NIA). The Automated and Electric Vehicles Act was passed on 20 July and the Charging Infrastructure Investment Fund was launched on 23 July.

"Build it and they will come"

The Government seems to see range anxiety as the main thing inhibiting the uptake of electric vehicles and that the solution is to build more chargepoints. The Road to Zero has 17 of its 46 policies focused on "support[ing] the development of one of the best electric vehicle infrastructure networks in the world". As far as possible, though, it wants the private sector to continue to lead on this, with Government support only where necessary. There are powers in the Automated and Electric Vehicles Act to mandate that chargepoints are built at motorway service stations and "large fuel retailers" (to be defined in regulations), but the Government will only use these if the private sector does not do this.

Other powers in the Act build on the Alternative Fuels Infrastructure Regulations 2017 to provide a uniform method of accessing public chargepoints, make data publicly available and set reliability standards, with the aim of making it as easy as possible for people to find and use a chargepoint.

The new Charging Infrastructure Investment Fund is a **£400 million fund, of which £200 is from the Government and £200 will be matched by the private sector**. The Request for Proposals to select a fund manager was launched on 23 July and will enable businesses to access finance to build more charging points.



The Road to Zero has 17 of its 46 policies focused on "support[ing] the development of one of the best electric vehicle infrastructure networks in the world"

Government support

Areas where the Government will intervene to support chargepoint development is through the planning process and by certain grants.

On the planning side, there will be a consultation on whether all new homes in England should have a chargepoint; and all new street lighting columns should include charging points, where appropriately located, in areas with current on-street parking. This is to encourage homeowners without off-street parking to use an EV. There will also be a consultation to increase the height limit for the Permitted Development Right in England for the installation of EV chargepoints in designated off-street parking areas; and a consultation on amending Building Regulations to require chargepoints in new non-residential buildings.

The Government will monitor market developments to see if any significant gaps appear in charging infrastructure over the medium term, and will consider whether to give direct government support in areas of market failure, which may include rural areas. This is a policy that the NIA also suggests, so watch this space.

In terms of grants, the Electric Vehicle Homecharge Scheme will continue until March 2019 and the Workplace Charging Scheme grant will be increased from £300 to £500 per socket.

There will be a second round of funding for local authorities to roll out dedicated taxi charging infrastructure, with a minimum of £6 million available.

Further down the road...

The Road to Zero has attracted criticism for sticking to the 2040 deadline for all new vehicles to be electric (especially as this definition now includes hybrids). Most commentators would like this moved forward by ten years. The Road to Zero has an interim target of at least 50% of new cars and 40% of vans sold in the UK to be ultra low emission by 2030; and a progress check in 2025 – which is when the Automated and Electric Vehicle Act powers may start to be used if the private sector is not doing enough to install chargepoints.

The NIA goes further than this and believes that 100% of new cars sold should be electric by 2030. The National Infrastructure Commission (NIC) agree that the private sector should be left to install chargepoints, with public subsidies only in areas where they are not commercially viable. The NIC thinks chargepoints should be “slow and smart” as the default, but there should be a visible network of public rapid chargers to alleviate range anxiety and encourage initial take-up. There should be a core network by the 2020s.

The NIA also advocates that local authorities should allot 5% of all public parking spaces for electric vehicles (so that they can park and charge at the same time) by 2020, and 20% of all spaces by 2025.

The Road to Zero has an interim target of at least 50% of new cars and 40% of vans sold in the UK to be ultra low emission by 2030

National Grid now predicts that there could be as many as 11 million EVs by 2030 and 36 million by 2050

Taxing decisions

We have been saying for a while now that the Government will need to think about taxation. As the ratio of electric vehicles versus internal combustion engines increases, the revenue from fuel duty (and vehicle excise duty) will decrease. The NIA recognises this issue and suggests that the Government should consider road use charging.

At this stage, there is no talk in the Road to Zero of changing the VAT that is charged on electricity sold to power electric vehicles. This remains at 20% for companies, or 5% when the electricity is used in the home.

Nor is there any mention of the Government controlling the resale price of electricity used to power electric vehicles, but this always remains a possibility if suppliers start increasing the price too much.

The energy angle

Electric vehicles feature strongly in each of National Grid's latest Future Energy Scenarios. National Grid now predicts that there could be as many as 11 million EVs by 2030 and 36 million by 2050. However, they do not see this as a problem for the electricity network, as smart charging technologies, consumer behaviour (charging at off-peak times) and vehicle to grid (V2G) technology should mean that the increase in peak electricity demand could be as little as 8GW in 2040.

This will only happen, though, if EV charging is done flexibly, not just at peak times. We are already seeing tariffs developing that encourage EV owners to charge at night rather than in the evening. Consumer behaviour will be driven by cost and benefits: in future, V2G technology will reward EV owners for making their batteries available to return power to the grid at peak demand times.

The Road to Zero acknowledges the need for co-ordination between the energy and automotive industries and will be launching an Electric Vehicle Energy Taskforce to bring them together to plan for future EV uptake and ensure the energy system can meet future demand. However, it is the EV infrastructure providers that need to be involved too, to make sure that they can install chargepoints without causing local constraints on the network – a problem that will worsen as EV penetration increases. National Grid and Ofgem (see their latest Future Insight) are aware of this issue and Ofgem have just issued a consultation on reforming access and forward-looking charging arrangements to address this.

Comment

The direction of travel is clear: EVs and ultimately autonomous vehicles are the future. The pace is still uncertain, but seems to be growing faster than forecast each year. EV networks are shaping up to be a new infrastructure asset class, which is already attracting interest from early investors. As always the Government treads a fine line between providing regulatory certainty while not stifling market initiatives. The UK has vibrant energy and automotive sectors and the Industrial Strategy appears to be designed to assist those sectors to compete in the emerging global low-carbon transport market.

12 September 2018

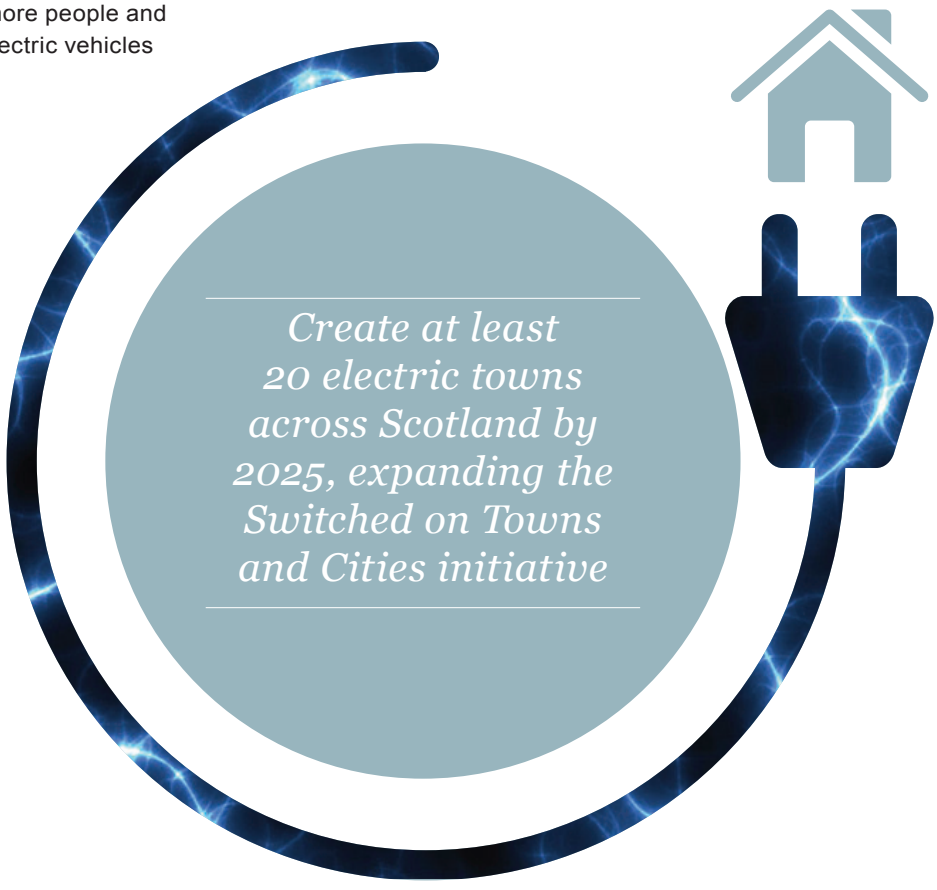
SCOTTISH PROGRAMME FOR GOVERNMENT 2018-19

The latest Scottish Programme for Government contains some encouraging joined-up thinking on transport and energy, recognising that the two are increasingly interlinked. We have pulled out some of the headline points.

Plugged-in households and Electric Towns

Last year the Scottish government set out its ambition to phase out the need for new petrol and diesel cars and vans by 2032, eight years earlier than in England and Wales. This year it is going further, with commitments to:

- create at least 20 electric towns across Scotland by 2025, expanding the Switched on Towns and Cities initiative.
- add 1500 new charge points in homes, businesses and communities including 150 new public charge points, investing £15 million
- launch 'Plugged-in Households' to widen access to electric vehicles, including through housing associations and car clubs
- increase the Low Carbon Transport Loan Fund from £8 million to £20 million to enable more people and businesses to make the switch to electric vehicles
- add more than 500 new ultra low emission vehicles to public sector fleets
- add over 100 green buses to the fleet through the £1.7 million Green Bus Fund
- improve access to the information from the national ChargePlace Scotland network of electric vehicle charge points to commercial operators, investors and network companies.



Mobility as a Service and Connected and Autonomous Vehicles

Simply switching from diesel and petrol to electric may not be the only way to improve the transport system. The Scottish government is also looking at innovation and will invest up to £2 million to support the testing of 'Mobility as a Service'. This has the potential to transform the way we use transport – making public and shared transport options as desirable as owning our own car.

Models being developed include using personal smart devices, such as phones and watches, to get personalised travel information, ticketing and payment for transport all through one portal incorporating all modes.

This funding will be available from 2019 and will complement the Government's existing work on smart ticketing.

The Government is also encouraging and supporting the research, development, demonstration, and deployment of Connected and Autonomous Vehicles or Driverless Cars. It will hold a summit in 2018 and explore with others how Scotland can best capitalise on the opportunities and benefits of this technology.

Low emission zones and air quality

The main reason for the switch from petrol/diesel to electric vehicles is to address the air quality issue. The Government plans to introduce what it calls 'Europe's most comprehensive network of cutting-edge remote sensing air quality monitors' on local and trunk roads, with the first monitors being deployed by August 2019. This will give accurate data on exhaust emissions and, along with the Transport (Scotland) Bill, should help the creation and enforcement of low emission zones.

Energy Strategy

Last year's **Scottish Energy Strategy** set out two targets for the Scottish energy system by 2030:

- the equivalent of 50% of the energy for Scotland's heat, transport and electricity consumption to be supplied from renewable resources
- an increase by 30% in the productivity of energy use across the Scottish economy

The Government will continue to work to achieve this and will report on progress later this year and publish the first Annual Report on the strategy in early 2019.

It will also continue its work to deliver a publicly-owned not for profit energy company by 2021 and will consult on the preferred model later this year.

Offshore energy

Let's not forget the rich energy resources surrounding Scotland in the North Sea. The Government recognises that there are still significant opportunities in the North Sea, with up to 20 billion barrels of oil equivalent remaining, which could sustain production for at least another 20 years.

Where resources have been depleted, the Government will continue to work to realise the benefits of decommissioning, advancing its commitment to provide financial support for establishing a Deep Water Port in Scotland, with Dales Voe in Shetland identified as the optimal UK location. The Scottish Government will continue to work collaboratively with the UK Government, the port, and industry to create a facility there.

For offshore wind the Government is providing a further £2 million this year to support innovation and help reduce the costs of offshore wind; and in the coming year will consult on a new Sectoral Marine Plan identifying future locations for large-scale offshore wind developments.

Conclusion

The Scottish Government's stated mission is to steadily increase annual infrastructure investment so it is **£1.5 billion per year higher at the end of the next Parliament than in 2019-20, increasing Scottish Government capital investment by an extra 1%** of Scottish GDP. The Programme for Government shows that transport and digital infrastructure – to use the data generated by our modes of transport in new ways such as Mobility as a Service – is a key area for this investment.

Increasing Scottish Government capital investment by an extra 1% of Scottish GDP

24 July 2018

WELCOME CLARITY ON CFD AUCTIONS

Claire Perry, the UK Energy and Clean Growth Minister, announced yesterday that the next Contracts for Difference (CfD) auction round would take place in May 2019 and then there would be a further round every two years.

This is welcome clarity for the renewable energy industry, and offshore wind in particular, as these are the only Government subsidies available and a firm pipeline of bi-annual auctions is good news for potential investors.

The next auction will be open to all 'Pot 2' renewable technologies, which will bid against each other for subsidies.

In practice, offshore wind is likely to dominate, as the costs of this technology have come down significantly in recent years, meaning it is able to offer lower bids. The Government estimate that each auction round would deliver up to 2GW of offshore wind capacity per annum in the 2020s, taking total offshore wind generation from 7GW currently (with another 7GW in progress), to 30GW by 2030, which would mean offshore wind generating over a third of the UK's power.

Remote island onshore wind projects will also be able to compete in this round, which is good news for the Scottish islands.

The total budget for the May auction and the future auctions is the £557 million that had been already announced as part of the Clean Growth Strategy. The auction parameters for the May 2019 auction will be set out later this year.

The Government estimate that each auction round would deliver up to 2GW of offshore wind capacity per annum in the 2020s

1 March 2018

CAPACITY MARKET UPDATE

It's been a while since we wrote an Insight about the Capacity Market and lots has been happening. We summarise the key recent developments.

Changes to rules and regulations

There were a number of changes to the Capacity Market Rules (which set out the technical detail of how the Capacity Market operates) during 2017. These mostly implemented changes proposed by a BEIS consultation, Capacity Market consultation: Improving the Framework issued in July 2017, with the response published in December 2017. The main changes were:

- The Capacity Market Rules were amended just before the latest auctions to reduce the de-rating factors for storage. Previously the de-rating factor for any kind of storage was set at 96.11%. However, most system stress events (when the capacity mechanism is called upon) last just over 2 hours, whereas batteries can often only discharge for 30-60 minutes – so they cannot cover the full time needed. The rules were changed to apply a sliding scale of de-rating factors, depending on how long a battery could discharge for. Only storage that can discharge for 4 hours or more will now get the full 96.11%. View the full table here.
- If plants receiving Capacity Market support do not demonstrate sufficient satisfactory performance days in any delivery year, this is now a new default termination event (previously it just meant that capacity payments would be suspended), and a termination payment of £15,000 per megawatt will apply.

Auctions

There have been two Capacity Market auctions recently. The T-1 auction, for capacity in 2018/19, took place on 30 January 2018 and the final results were confirmed on 13 February. The T-4 auction, for capacity in 2021/22 onwards, took place on 6 February and the final results were confirmed on 20 February. There was a slight change from the provisional results.

T-1 auction

The results were:

A clearing price of £6/kW/year, the lowest yet, with 5.8GW of capacity secured.

54.3% of capacity entering the auction was successful. The majority were CCGT (closed cycle gas turbine) or OCGT (open cycle gas turbine) generation, and all of these were existing generating units, but demand side response, coal/biomass, and CHP and autogeneration also did well.

Coal/biomass comprised over half the total capacity that exited the auction as prices fell too low, followed by DSR. Almost 70% of new build storage also exited. Shortly after the auction results, Eggborough coal power station confirmed it would close in September 2018 as it had failed to secure a capacity agreement.

There were a number of changes to the Capacity Market Rules (which set out the technical detail of how the Capacity Market operates) during 2017. These mostly implemented changes proposed by a BEIS consultation, Capacity Market consultation: Improving the Framework issued in July 2017, with the response published in December 2017

T-4 auction

The final results, published on 20 February, differed slightly from the provisional figures in that an extra 5MW (3 extra new-build storage projects, 2 from Limejump and 1 from KiWi Power) were included. The results were:

A clearing price of £8.40/kW/year, much lower than previous T-4 prices of £18/kW for 2019/20 and £22.50/kW for 2020/21.

50.42GW of capacity was secured, with 23.83GW exiting as the price fell too low for them.

Almost 86% of successful capacity is existing generation, and 45% is CCGT. No new CCGT projects (such as SSE's Keadby) won capacity, although two large new-build EfW plants (SSE's 66MW Ferrybridge Multifuel Energy 2 and Covanta's 57MW Rookery South) secured agreements.

Interestingly, 6 interconnectors won capacity agreements, 3 of these (Eleclink, Nemo and IFA2) being new-build projects. This has caused some controversy, since these benefit from the cap and floor regime, which gives them a guaranteed minimum income, and are exempt from transmission charges and also the carbon price floor. Some say that this means Britain is importing power generated by European coal plants instead of building new, cleaner gas power plants itself.

The auction was oversubscribed, with 74GW of capacity bidding for 50GW of contracts. The main types of technology exiting the auction once prices fell too low were new-build CCGT (11GW) and coal/biomass (7.6GW). Only Drax and Ratcliffe coal plants secured capacity agreements. 80% of batteries and around 50% of DSR also lost out.

Medium Combustion Plant Directive

A further legislative development that affects certain generating plants that may have just been granted a capacity agreement is the enactment of the Medium Combustion Plant Directive into UK law, by the Environmental Permitting (England and Wales) (Amendment) Regulations 2018. These Regulations only came into force on 30 January 2018, but they affect any "specified generator" that was awarded a capacity agreement that remains in place after December 2018 (so any that have just been successful in these auctions). They mean that from 1 January 2019 a "specified generator" combustion plant used to generate electricity between 1 and 50MWth (including individual smaller generators if together on the same site they add up to 1MW) will need a permit to be operated and must comply with standard permit conditions.

Comment

The recent rule changes have been bad news for battery storage projects, as the de-rating factors mean that the capacity payments they would have received were too low to be economically viable as the only source of revenue. Coal also suffered, with Eggborough announcing its closure and many other plants unable to meet the low clearing price. Yet again, no new gas plant secured a capacity agreement prompting criticism from some quarters that in failing to stimulate development of new gas the Capacity Market was failing to achieve one of its main aims.

However others argue that the Capacity Market is achieving exactly what was intended with the competitive auctions driving down cost to achieve the best result for the consumer on a technology neutral basis. Interconnectors, for example, is one of the technologies that did do well out of these auctions. It remains to be seen if this is a trend that will continue, or whether Ofgem will start to scrutinise this more looking at the interconnector charging regime and the reliability of an interconnector (which relies on the generators that sit behind the interconnectors) in providing capacity.

1 November 2017

AUTOMATED AND ELECTRIC VEHICLES BILL PUBLISHED

The Government has had several attempts to bring in legislation to support the uptake of electric vehicles. Finally the measures to encourage the uptake of electric and hydrogen-powered vehicles, have reappeared in Part 2 of the Automated and Electric Vehicles Bill. Read our analysis here...

The Government has had several attempts to bring in legislation to support the uptake of electric vehicles.First it announced the Modern Transport Bill in the 2015 Queen's Speech, which was eventually, following a consultation, put before Parliament as the Vehicle Technology and Aviation Bill in February 2017. Then the snap General Election stopped that Bill in its tracks. Finally the measures to encourage the uptake of electric and hydrogen-powered vehicles, known as ultra-low emission vehicles or ULEVs, have reappeared almost word for word in Part 2 of the Automated and Electric Vehicles Bill. This had its first reading in the House of Commons on 18 October 2017 and its second reading on 23 October. It is now being considered in Committee.

The measures in Part 2 of the Bill focus on addressing three challenges to the uptake of ULEVs:

- the consumer experience of using the infrastructure – consumers need to know where to find and use charge points
- 'smart' charging (the way the charging infrastructure interacts with the electricity system) – to balance energy supply and demand
- the future provision of infrastructure – whether to require operators of motorway service areas and large fuel retailers to provide a minimum number of charge points

Consumer experience of infrastructure

The Department for Transport (DfT) will be able to require operators of public charging points to use a certain method of payment or a certain type of plug, so that any consumer can use any charging point without having to be a member of a certain scheme. There was no clear consensus in the consultation on whether a roaming platform or a specific ad hoc access method would be the best approach, so the Bill is sufficiently vague as to allow the DfT to decide nearer the time.

At the moment there is a lack of consistency in what information charge point operators make publicly available and no standardised format. The industry agreed that this was a main cause of "range anxiety" for electric vehicle (EV) drivers, who need to know where their next available charge point is, so they don't get stranded. The Bill gives the DfT power to require public charge point operators to make available "such information as the Secretary of State considers likely to be useful to users or potential users of the point" and goes on to list examples such as the location of the point and its operating hours, available charging/refuelling options, method of payment, means of connection, and whether the point is in working order/in use.

The consultation had also proposed a power to set standardised pricing information at charge points, but the DfT has instead identified existing powers they could use, so will bring forward new regulation at a later date.

Smart charging – infrastructure and the electricity system

Nearly everyone who responded to the consultation on the Modern Transport Bill agreed that the Government should take powers to require charging infrastructure to have 'smart' functionality to receive, understand and respond to signals sent by Distribution Network Operators, National Grid and energy suppliers to balance energy supply and demand. The energy industry (and also the transport industry) see the opportunities here to use the batteries in electric vehicles as a mobile energy storage solution. It seems that consumers will probably end up bearing most of the cost, but the obligation to make sure a charge point has the prescribed smart functionality will be on sellers and installers of charge points rather than manufacturers.

The industry agreed that this was a main cause of "range anxiety" for electric vehicle (EV) drivers, who need to know where their next available charge point is, so they don't get stranded

Future charging infrastructure

Finally, the Bill allows the DfT to require large fuel retailers or service area operators to provide public charging points. The definitions of "large fuel retailers" and "service area operators" are left to the regulations, but the consultation envisaged that all motorway service areas would be covered and that large retailers could be defined by space and/or turnover. The consultation recognised that there are four key factors which any new mandatory requirement would need to take account of:

- the commercial viability of fuel retailers and their forecourts, and motorway service areas, and the effect that mandatory EV infrastructure would have
- the space available given total land take and existing facilities
- the capacity of the local electricity grid
- the existing or future proximity of EV infrastructure near the fuel retailer or service area

Locations where it would not be possible or sensible to have EV infrastructure would be exempt.

High level and flexible

The general theme of the measures is to give the Government broad powers in principle but to flesh out the detail in regulations at a later stage. This is an emerging industry and some respondents to the consultation were concerned that regulating it too much from the start would stifle development and innovation. There will be no legal requirements placed on the industry at the moment, even when the Bill is passed. It just gives the DfT the power to make regulations at a later stage which will contain the requirements, and even then the Bill allows for there to be exemptions.

Comment

Whilst these measures won't have any immediate effect, the Government has committed to end sales of new petrol and diesel vehicles by 2040 and the Bill sets out the framework of powers that will help make that happen, identifying electricity and hydrogen as the emerging road transport fuels.

It is part of a wider series of measures to support ULEVs including grants for installing charge points at home and work, enhanced capital allowances for charging infrastructure investments and an additional £80m of Government funding for charge points. Whilst the legislative framework is now beginning to evolve, the supply chain and delivery infrastructure for electricity and hydrogen refuelling are also evolving and this is an opportunity to get involved and shape the regulation of this emerging industry at an early stage.

The Public Bill Committee is currently receiving written evidence, which they will take into consideration and possibly reflect in an amendment to the Bill. See the Parliament website for details on how to submit written evidence.

ULEVs and CAVs (Connected and Autonomous Vehicles) feature in the Trends in Transport that we are tracking and reporting on.

AG brings cross-sector expertise to its work on EV projects, which includes experience advising on investment in and delivery of charging infrastructure and emerging commercial and regulatory advice from our Energy and Transport teams. Please contact one of our EV Team for more information.

14 December 2017

LEEDS LEADS THE WAY ON CLEAN AIR

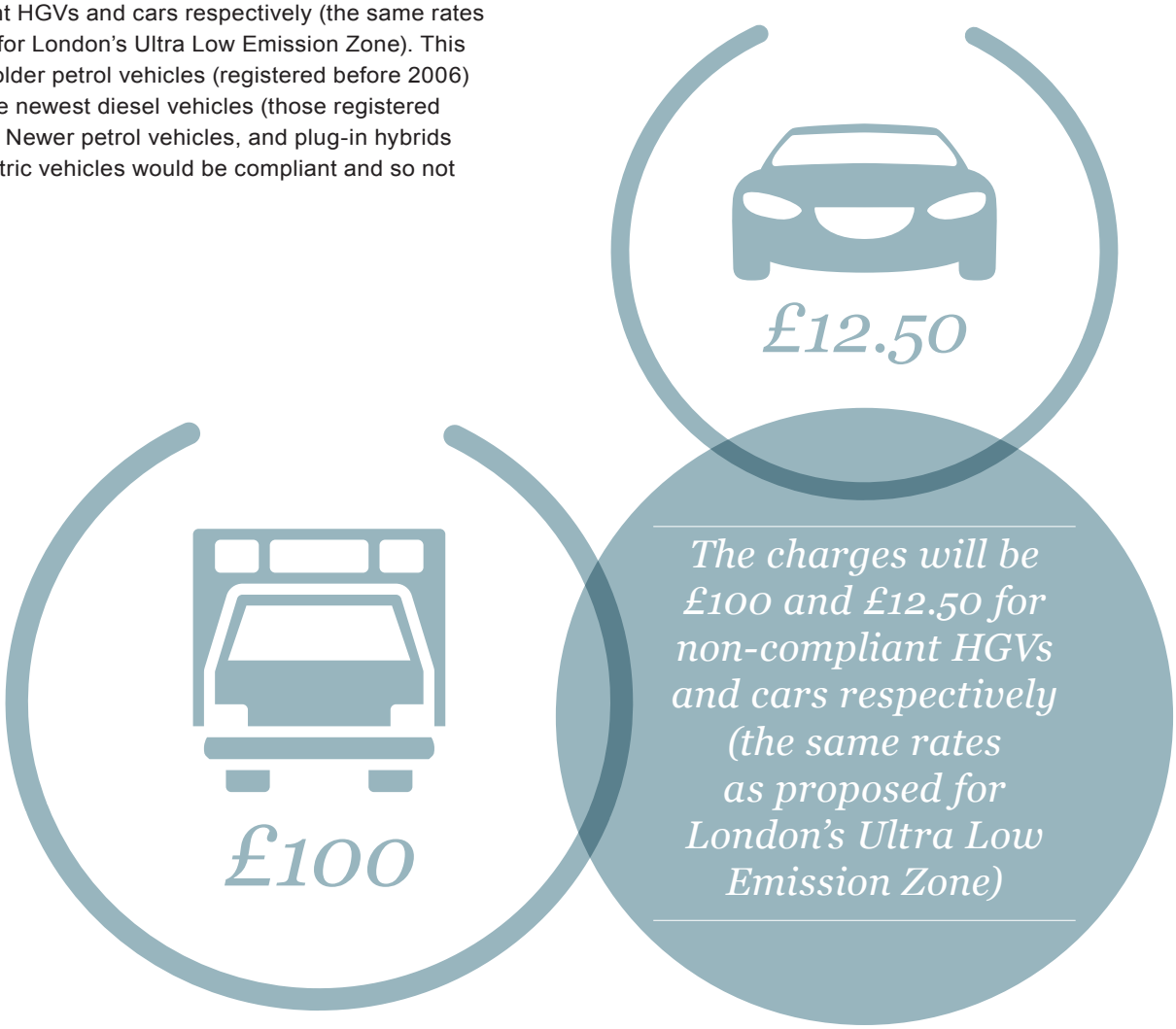
Today (13 December) Leeds City Council's Executive Board will decide whether to introduce a clean air zone next year.

The background to this is the UK's legal requirement to comply with the EU Air Quality Directive. As has been widely reported, the UK has so far not complied and in July 2017 published a National Air Quality Plan (Clean Air Strategy) putting the onus on the 29 core cities which do not meet clean air requirements (of which Leeds is one) to come up with solutions to meet air quality requirements in the shortest possible time.

Leeds has looked at a number of options and has decided the best is to implement a Clean Air Zone (CAZ) within the outer ring road, a fairly wide geographic area.

The CAZ will apply to HGVs, buses, taxis and vehicles for private hire. At the moment it is not intended to apply to light vehicles (vans) and private cars. It would mean that HGVs, buses and cars that do not meet Euro 4 petrol or Euro 6 diesel standards would have to pay a charge to enter the CAZ. The charges will be £100 and £12.50 for non-compliant HGVs and cars respectively (the same rates as proposed for London's Ultra Low Emission Zone). This would catch older petrol vehicles (registered before 2006) and all but the newest diesel vehicles (those registered before 2015). Newer petrol vehicles, and plug-in hybrids and fully electric vehicles would be compliant and so not charged.

The Leeds scheme will be similar to London's "Ultra Low Emission Zone" which comes into force from 8 April 2019. As a precurser, from 1 January 2018 all taxis licensed for the first time must be zero emission capable. This is partly responsible for Transport for London's push for electric vehicle infrastructure: they aim to install 150 new rapid charge points by the end of 2018, of which 90 will be for taxi use only. TfL are also helping to fund a Government-led Plug-in Taxi Grant, which gives taxi drivers up to £7,500 off the price of a new zero-emission taxi.



Leeds is already encouraging drivers to switch to low emission vehicles by offering free parking to ultra low emission vehicles in the city centre

Leeds is already encouraging drivers to switch to low emission vehicles by offering free parking to ultra low emission vehicles in the city centre along with 86 charging points throughout the city. If private hire drivers are to avoid a CAZ charge they will need to switch from diesel to electric cars. With approximately 4000 private hire vehicles affected, it will be a significant challenge to get the charging infrastructure in place to support this and the council is aware that in order to make this step change that it must look to provide additional support to this sector. It has already worked with partners within the West Yorkshire Combined Authority to secure funding from the Office for Low Emission Vehicles (OLEV) to deliver an ULEV taxi infrastructure scheme. This has secured £1.98 million capital grant funding to deliver 88 charge points over the three year delivery period to 2019/20, of which 33 will be in Leeds.

The council has also requested additional funding from central government to provide incentives to those drivers who make the transition to petrol hybrids or electric. The council will also work with government to explore other potential ways of supporting this sector and will ask that the taxi and private hire industry provide feedback via the consultation process as to which support measures they feel would be most effective.

The report presented to the Council Executive makes no mention of how the CAZ will be policed. Presumably vehicle recognition technology or mobile telephone registration will be used, as recommended by the Government in its Clean Air Zone Framework of May 2017, but significant infrastructure (physical or digital) investment will be needed. Leeds will also have to implement a register of private hire vehicle owners for such a scheme to work.

There should be funding available for the necessary infrastructure (cameras and signage) but the contractual and legal nexus needs to be carefully thought through. Leeds will want to avoid making the same mistake as York, which illegally designated Lendal Bridge a bus lane and charged unsuspecting drivers a £30 fine for using it, leading to the Council having to repay £1.8 million of fines. There are powers in Part III of the Transport Act 2000 to levy a Clean Air Zone charge and the council will need to make sure it follows the correct statutory process.

This is the start of CAZs and we expect other cities to follow. If approved, the Leeds consultation will begin in January and the Council hopes to implement the scheme by the end of 2018.

16 October 2017

THE CLEAN GROWTH STRATEGY HAS FINALLY BEEN PUBLISHED, BUT WAS IT WORTH THE WAIT?

Richard Goodfellow, Partner and Head of Energy and Utilities, comments on the long-awaited Clean Growth Strategy.

The long-awaited Clean Growth Strategy has finally been published - the Government's plan outlining how it will meet its legal commitment under the Climate Change Act 2008 to reduce UK greenhouse gas emissions by at least 80% by 2050. Although the fifth Carbon Budget for 2029-32 was approved last year, the vote to leave the European Union and snap general election delayed the strategy's publication. So, was it worth the wait?

As seems par for the course with any Government policy document these days, it contains a lot of spin. There is much talk of how the UK is a world-leader in climate change and clean growth, and it's right. Clean growth (growing national income, while cutting greenhouse gas emissions) can be achieved and the UK has made strong progress. UK GDP has grown by 67% since 1990, whilst emissions have fallen by 42%.

Lowering emissions, however, doesn't mean scaling back growth - it is quite the opposite. The low carbon economy could grow 11% per year between 2015 and 2030 - four times faster than the projected growth of the economy as a whole. In fact, clean growth is at the heart of the government's Industrial Strategy and will have an impact on every sector of the economy.

The plan covers a wide variety of sustainability and climate change topics, and we will be delving deeper into the impact of the Clean Growth Strategy on a range of different sectors in the weeks and months ahead, but some key themes emerging were the focus on green finance, energy efficiency, transport, and substantial investments in research and innovation.

In green finance, to meet the carbon reduction targets set out, the government needs private sector investment. In response to this, it was announced that a green finance taskforce, comprised of senior representatives from the finance industry and government, will be set up to develop ambitious policy proposals. It highlights that the government recognises the need to work hand-in-hand with the private sector to implement funding and investment.

Energy efficiency has also been earmarked as a key theme, for both homes and businesses, and it will be the public sector that leads the way. In transport, it will rely on a near complete switch to electric vehicles to bring down emissions.

A notable part of the strategy was its commitment to substantial investment in research and innovation. A significant £2.5 billion will be invested in total, split between transport, power, cross-sector, smart systems, homes, business and industry, and land use and waste. Transport, however, will get the biggest slice of investment with 33% of the total figure going towards it.

But there are some things that the Clean Growth Plan does not mention, that we hoped it would. There is nothing on solar PV or onshore wind, despite them being extremely successful low-carbon technologies. There are also no commitments on tidal power and little mention of the relative roles of nuclear energy and renewable energy in providing baseload power generation, other than to reiterate the commitment to nuclear power through Hinkley Point C, and to make sure there's a "competitive price for future projects in the pipeline".

Most disappointingly, there are no substantial policy commitments on carbon capture, use and storage (CCUS), just some woolly wording around demonstrating international leadership by collaborating with global partners and investing up to £100 million in CCUS and industrial innovation.

It outlines that the government will work in partnership with industry through a new CCUS Council, to "put us on a path to meet our ambition of having the option of deploying CCUS at scale in the UK", but it provides little comfort for the CCUS industry, when the second CCUS competition was scrapped after costing £100 million with a £1 billion prize.

Even if the government implements all the policies and proposals in the Clean Growth Plan, it will still fall short of the fifth Carbon Budget by 9.7%, and may have to carry forward some surplus from earlier budgets to meet its legal obligations.

The low carbon economy could grow 11% per year between 2015 and 2030

What the Clean Growth Plan does give us is a clear indication of the direction of travel, even though some of the detail is still to be worked out. It sets out a possible pathway to 2032, which includes a target to reduce emissions from business and public sector by 30% through energy efficiency improvements, and a 14% reduction in industrial energy carbon content by switching to cleaner fuels.

It also points towards reducing emissions from homes by 19%, and a fall in household energy use by 9% through low-carbon heating and energy efficiency improvements. Reiterating the focus on electric vehicles, it targets a 29% drop in emissions from transport.

The strategy also looks beyond 2032, pointing towards three possible pathways to 2050: electrification, hydrogen and emissions removal (the use of biomass plus CCUS). For 2050 targets to be met, the reality is likely to be a combination of them all.

The pathways to 2032 and 2050 have many steps in common, perhaps providing a possible indication of where government support will be directed. These include making homes and commercial buildings more energy efficient, a shift to low carbon heat sources, continuing to decarbonise electricity, more electric vehicles, and improving industry efficiency with a transition to clean fuels.

If the 165-page Clean Growth Plan wasn't enough food for thought, BEIS on the same day released several consultations, responses and calls for evidence on ending unabated coal generation by 2025, decarbonising the public sector, the design of a new £18 million industrial heat recovery programme, and the reform of the Green Deal framework, amongst others.

Looking ahead, there are further policy papers mentioned in the Clean Growth Plan that are worth looking out for. These include a 25-year Environment Plan, a long-term strategy for the UK's transition to zero road vehicle emissions, and the Industrial Strategy White Paper.

Given the amount of time it has taken for the Government to release the Clean Growth Strategy, it is disappointing that there is little in the way of firm policy and a lot of things left to be consulted on in the future.

Yet it is an opportunity for the UK to pin its hopes of economic growth after Brexit on the low-carbon economy. Industry must ensure it is involved in all aspects of policy development in the future, and we will set out what this could mean for a range of sectors in the months ahead.

3 August 2017

NATIONAL GRID'S FUTURE ENERGY SCENARIOS 2017

The energy world is changing rapidly and all those active in the sector have not only to keep up but also, perhaps more importantly, to work out what might happen next and plan accordingly. National Grid as Britain's independent electricity and gas system operator, is well placed to do this.

Every year in July it publishes its Future Energy Scenarios document, which is used as the starting point for its regulated long-term investment and operability planning as well as a reference point for other National Grid reports. Its Future Energy Scenarios 2017 (FES 2017) was launched to a packed audience on 13 July and provides a fascinating insight into how recent trends and developments in energy markets are impacting National Grid and the way in which the system is used and what the future of energy might look like.

Scenarios

Since it is impossible to predict exactly how things might pan out, each year National Grid model four different scenarios as to how the energy system might develop. Each scenario considers energy supply and demand on a whole system basis, incorporating gas and electricity transmission and distribution.

This year two of the scenarios are different from previous years. Gone Green has become **Two Degrees** – a world where environmental sustainability is top priority. This assumes the highest level of prosperity and is the only scenario where all UK carbon reduction targets are achieved. In our view it also seems the most unlikely of the scenarios, as it requires much investment and a great deal of policy support in the near future.

No Progression has become **Steady State**, recognising that if things carry on as they are, there will be some progress, it will just be very slow. This is a world focused on security of supply and short-term thinking, with the lowest level of prosperity.

The other two scenarios are the same as last year. **Slow Progression** is a world focused on long-term environmental strategy, i.e. there is green ambition but less money available to realise it.

Consumer Power is a world which is relatively wealthy and market driven. This seems to be the more likely scenario given current trends, but with the most fluctuation in supply and demand.

The scenarios have also been extended out to cover 2040-50 – so for the first time we can see if the UK will meet its 2050 Climate Change Act targets. It doesn't look promising – only under the Two Degrees scenario are the targets met; and that would take a concerted effort, not least from Government on the policy front, starting now.

Sensitivities

Recognising that even with four different scenarios, anything could still happen in the energy world, National Grid have introduced a number of sensitivities, representing possible futures beyond the confines of the four scenarios. They start with "what if" questions:

What if...?

...we used hydrogen to decarbonise heat?

So instead of using electrification of heat pumps to decarbonise heat, we were to use hydrogen (and CCS) instead of natural gas to meet our 2050 targets. This sensitivity uses the H21 Leeds City Gate project to convert Leeds to hydrogen as a starting point and assumes 17 cities are then converted, with hydrogen supplying 28% of total heating demand by 2050. This would increase gas demand to around 1,100TWh/year but the infrastructure could cope. Carbon capture and storage is essential for this sensitivity to work.

For more information about the potential for using hydrogen, see our thought piece article **Hydrogen: more than just hot air?**

...there was a rapid take-up of electric vehicles?

If the cost of electric vehicles continues to fall rapidly, and air quality becomes a key priority, then we could see a rapid take-up of pure electric vehicles. This could mean that all cars sold after 2040 will be pure electric vehicles (as indeed the Government has since announced) and the sale of plug-in hybrids ceases by 2025. The additional annual energy demand just to support these extra vehicles

will be 21 TWh in 2030 and 90 TWh by 2050. Peak demand could be an extra 30GW per year (50% higher than now) if how those vehicles charge is unconstrained. This would obviously put a lot of extra strain on the network and is the reason why the government is keen to support the use of vehicle to grid technology, so that electric vehicles can help to manage, rather than increase, demand.

…millions of consumers and businesses install renewable generation in their homes and workspaces?

Consumers could become "prosumers" – producers and consumers of energy at the same time. This could mean the 2050 carbon target is met by having much more distributed generation with storage providing flexibility. The Smart Systems and Flexibility Plan, launched a week or so after FES 2017, could help facilitate this. By 2050, 65% of generation could be embedded or behind the meter. A large proportion of this is intermittent, so storage has a crucial role, with 42GW installed by 2050. It would still be difficult to meet high winter demand unless excess energy is stored as hydrogen and used later to provide heat.

…society switches away from fossil fuels to electricity with greater reliance on renewable generation?

The energy industry is divided about the best way to achieve decarbonisation and climate change targets and the Two Degrees scenario shows them being met in a balanced way, but to shake things up a bit National Grid have looked at what would happen if we went down the full electrification route. This would mean a widespread switch from gas to electric heat pumps, much greater use of electric and hydrogen fuel cell vehicles, and all this powered by more renewable generation, mainly wind. Total electricity demand rises to 475TWh by 2050, higher than in any of the four scenarios, but some gas (about a quarter of today's demand) is still needed, with investment in bioSNG and biomethane.

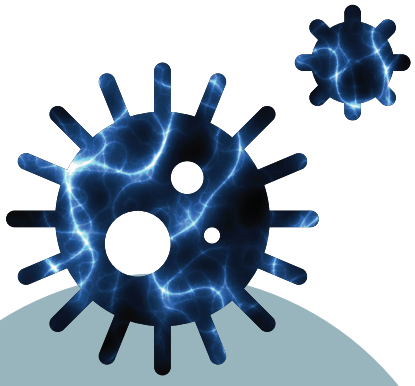
Trends

In all the scenarios and sensitivities there are some common trends:

- Storage is common to all, and has a higher starting point and faster build compared to FES 2016. There is strong initial growth in storage to 2020 under each scenario, but then they differ
- Combined gas and electricity demand falls in all scenarios, driven primarily by decrease in gas consumption for power generation, but if not managed, peak electricity demand could grow by almost 1GW per year after 2020 due to the uptake of electric vehicles and the decarbonisation of heat
- There is a shift towards decentralised and renewable generation in all scenarios, only the pace and extent differs
- This brings a need for more flexibility to balance supply and demand
- New nuclear is needed in all scenarios, but there may be a gap between plants decommissioning and new plants coming online
- Offshore wind grows in all scenarios
- Imported gas becomes more important in three out of the four scenarios; and shale gas features in Consumer Power and Steady State

Comment

If Britain has any hope of meeting its climate change targets, we need to start decarbonising heat and transport now. The scenarios and sensitivities show a number of ways this could be done, with very different outcomes, depending on whether a policy- or market-driven approach is adopted. What we do know is that there is a need for more flexibility and more storage solutions as we shift to more decentralised and renewable generation, but we should take a whole system view, looking at how electricity, gas and transport fuels interact. Whilst Government may have announced its Electricity Market Reform measures in 2013 its clear that true reform of the way in which we use and manage our energy needs has really only just begun.



If Britain has any hope of meeting its climate change targets, we need to start decarbonising heat and transport now.

7 July 2017

NATIONAL GRID SNAPS INTO ACTION ON ELECTRICITY BALANCING SERVICES

Recently National Grid published its System Needs and Product Strategy consultation looking at the way the electricity system is changing in Great Britain and how the range of services that it uses to balance supply and demand needs to change to meet those changing needs.

This is the start of a major reform of grid balancing services in consultation with industry and is worth a read both to understand how system needs are changing and to see how National Grid is intending to revamp its balancing services products to better meet those needs.

System needs

The increasing amount of intermittent renewable energy on the system, and decreasing amount of "traditional" synchronous generation, is making it harder to keep the system balanced using the range of products that are currently available. National Grid identifies five key future system needs (in the order that it calls on them in real time):

- Inertia and Rate of Change of Frequency (RoCoF): system inertia is expected to decrease, which increases the RoCoF and can cause some generators to "trip" and disconnect from the grid
- Frequency Response: National Grid needs response that acts faster than the products it currently uses and needs flexibility closer to real time
- Reserve: this can be upward (an increase in generation/ decrease in demand) or downward (a decrease in generation/increase in demand) and at the moment there are a number of overlapping products to manage this
- Reactive Power/Voltage Support: the need has moved from generation to absorption of reactive power, driven by low transmission demands and increased reactive power contribution from distribution networks
- Black Start: there are opportunities for new providers to enter black start contracts from 2018 and National Grid is looking to open this up to alternative forms of generation

Product strategy

To meet these needs, National Grid has over time developed a range of 21 products (not including the Capacity Market), each with its own requirements and each procured in a different way (bilateral agreements, auctions, tenders). This has led to some products being oversubscribed and other products not as popular, even though they offer a higher price.

National Grid is proposing a three-stage programme of rationalisation, standardisation and improvement. First it will reduce the number of products (for example, getting rid of Enhanced Frequency Response and Firm Frequency Response and replacing them with a single new product). Then it is looking to standardise products, moving from a number of precisely defined products to a smaller number of products which have a number of parameters. In the longer term National Grid will work with industry to improve and develop the product suite beyond just standardising the existing products.

To meet these needs, National Grid has over time developed a range of 21 products (not including the Capacity Market), each with its own requirements and each procured in a different way (bilateral agreements, auctions, tenders)

Next steps

This consultation is open until 18 July and National Grid will report back at the end of September 2017.

We can expect:

- A new frequency response product (replacing FFR and EFR) to be designed and implemented by March 2018
- New reserve products that ensure: sufficient flexibility is available close to real time
- market access for both BM (balancing mechanism) and non-BM providers
- compatibility with pan-European reserve services by 2018/19
- A new reactive market will be designed and implemented by the end of 2018/19
- In the longer term, investigate how black start can be procured using distributed energy resources

Distributed generation and interconnectors

At a time when embedded benefits are being been cut, this is good news for distributed generation as National Grid has identified that a number of its current balancing services are not available to distributed generators and that this needs rectifying. Reactive products and black start services should soon be redesigned to ensure embedded generators can participate.

National Grid is also taking the changing interconnection arrangements into account, including the new cross-border trading arrangements coming into force next year that will allow one hour ahead trading instead of the current three hours ahead (and the increased uncertainty in generation and demand that this will cause); and the need to continue imposing ramp limitations, to prevent increased interconnection impacting system frequency.

The consultation is on National Grid's Future of Balancing Services website here.

29 June 2017

OFGEM TO CUT EMBEDDED BENEFITS FROM APRIL 2018

Ofgem will cut the triad avoidance payment for embedded generators from £47/kW currently to between £3 and £7/kW over three years.

Background

Our previous article Ofgem Minded to Cut Embedded Benefits explains the background.

The decision

Ofgem confirmed its decision in a meeting on Thursday 15 June and issued a press release on 20 June along with an open letter to stakeholders. It published its full decision and updated Impact Assessment late on 22 June.

The level of triad avoidance payment will be reduced to the level of avoided Grid Supply Point costs, which are the only true benefit that embedded generation brings, according to the Decision. Grid Supply Point costs are the cost of reinforcing the point where the distribution network connects to the transmission network. Generation connected to the distribution network takes demand off the transmission network, so offsets the need for reinforcement. National Grid estimate the value of this avoided reinforcement cost as £3-£7/kW, slightly higher than the £2/kW mentioned in the consultation, but still significantly lower than the current level of around £47/kW.

Reducing the level of triad avoidance payment to the avoided Grid Supply Point costs will take place gradually over three years from April 2018 to 2020.

There will be no “grandfathering”.

What does it mean for embedded generators?

Of the 30GW of embedded generation, the 10GW of “dispatchable” generation – that can control when they produce electricity – will be most affected. This is diesel and small gas plants, CHP plants and biomass generators. Ofgem’s Impact Assessment has this table showing the impact by technology types:

TECHNOLOGY	IMPACT
Thermal CHP (Gas), Waste and Waste CHP, Biomass and Biomass CHP, OCGT, CCGT, Gas and Diesel Reciprocating Engines	High (more than £50/kW)
Anaerobic igestion and CHP, Sewage gas and CHP, Landfill gas and Hydro	Medium (£30-£50/kW)
Tidal, Wave, Wind (onshore and offshore)	Low (under £20/kW)
Solar	n/a

Many of these plants won capacity agreements in the 2015 Capacity Market auction, where the financial commitment milestone (where they have to demonstrate a financial commitment to be ready 2.5 years before being called on to supply capacity in 2019) was on 22 June. Ofgem gave early warning of their decision before issuing the full decision letter, to give such plants chance to consider whether or not they want to commit to supplying capacity in 2019 given the reduction in embedded benefit payments, which may well impact on the financial viability of a plant.

There were several proposals put forward by industry for some sort of 'grandfathering' to protect plants that had won capacity agreements, since they had bid in to the Capacity Market at a lower price on the basis of the revenue they thought they would be getting from embedded benefits. From the tone of the Decision, Ofgem seems firmly of the view that this would be a market distortion and that investors should have been aware that these revenue streams have been the subject of industry debate over a number of years and taken account of this risk.

Ofgem expects that reducing the triad avoidance payment to smaller embedded generators may lead to those generators increasing their future Capacity Market bids, but still thinks that consumers will save money overall and in the long term will lead to lower costs and more efficient investments. Ofgem's modelling shows that it expects future capacity contracts to be awarded to more gas plants and fewer diesel plants, which will also reduce carbon emissions.

The only good news for embedded generation is that the changes will be phased in over the next three years, starting April 2018, so will not affect this winter's triad avoidance payments. Ofgem will reduce the triad avoidance payment by one third each year, until by 2020 they reach the level of avoided Grid Supply Point investment cost (between £3 and £7/kW).

Industry reaction

The industry has reacted to this news mainly with disappointment, although it was not unexpected given that Ofgem was already "minded to" cut the triad avoidance payments. Uniper (formerly part of E.ON) and the Citizens Advice Bureau welcomed the announcement but the Renewable Energy Association called it a "ruthless cut". The Anaerobic Digestion and Bioresources Association called it "a misguided decision" and called for a holistic charging review.

Targeted charging review

We are still awaiting the outcome of the Targeted Charging Review of the other embedded benefits. This closed on 5 May so we can expect a decision shortly.

If Ofgem decides to launch a Significant Code Review, this will take at least 18 months to conclude, then implementation will be after that.

17 March 2017

OFGEM MINDED TO CUT EMBEDDED BENEFITS

Ofgem is 'minded to' accept a proposal to cut the triad avoidance payment for embedded generators by 95% over three years.

Background: embedded benefits

Let's go back a step and explain the background, before looking at what this means and why it is important.

Small generators of less than 100MW that are connected to the electricity distribution network rather than the transmission network are known as "embedded generators". By not being directly connected to the transmission network they avoid paying certain charges and even get paid by electricity suppliers to generate electricity at times of peak demand. These benefits are known as "embedded benefits". In simple terms they include:

- Not having to pay National Grid any Transmission Network Use of System (TNUoS) charges, since the generators are not connected to the high-voltage transmission network
- 'Triad avoidance' payments. 'Triad periods' are the three half hour periods of highest system net demand during November-February (this is worked out afterwards so no one knows in advance when a triad period will be). Electricity suppliers have to pay TNUoS demand charges on the basis of their average net demand over those triad periods. If suppliers have an arrangement with an embedded generator, they can ask that embedded generator to generate electricity at times of (likely) highest demand (hoping that three of those will end up being a triad period) and in effect net off the supplier's demand. This means the electricity supplier pays a lower TNUoS demand charge and will share a significant part of this saving with the embedded generator

The value of the current triad avoidance benefit is £45/kW (which to put it in context is over double the latest Capacity Market clearing price) and is forecast to increase in four years to £72/kW.

The main beneficiaries of triad avoidance payments are small power plants that can generate at times of peak demand – so not solar (as the triad periods are all winter evenings) and not always wind (as it will depends if it is windy during a triad period) - but usually diesel, gas, CHP, AD and some storage.

The issue: market distortion

Embedded benefits are becoming a problem for Ofgem. More and more generators are choosing to connect to the distribution network rather than the transmission network, which leaves fewer transmission-connected generators to pay the TNUoS charges. The TNUoS charges go up, so suppliers pay embedded generators more to generate at triad periods (to reduce their TNUoS demand charges), which increases the triad avoidance payments and encourages yet more generators to connect to the distribution network – a feedback loop that (as mentioned above) means in four years' time the triad voidance benefit is forecast to be £72/kW.

Ofgem believe that this has led to these market distortions:

- Dispatch – Smaller embedded generators generate 'out of merit' (i.e. instead of the cheapest and most cost-effective generators running first, embedded generators run when normally, if it weren't for the embedded benefits, it would not be as cost-effective for them to generate first)
- Wholesale price – by running 'out of merit', the wholesale market price is distorted and artificially damped at peak times
- Capacity Market – embedded benefits give smaller generators a competitive advantage so they can bid into the Capacity Market at a lower price, potentially pushing out more expensive, but ultimately more efficient, plant
- Inefficient investment in generation capacity – although it might be more efficient to locate on the transmission system, generators choose the distribution system instead so that they can get embedded benefits

This ultimately leads to higher costs for consumers, as suppliers recover the cost of paying embedded generators by putting it onto customers' bills.

Why now?

Ofgem has been accused by the Association for Decentralised Energy (ADE) and others of rushing the embedded benefits review, but both Ofgem and National Grid have had this issue on their radar for a long time (the consultation points to discussions going back to 2007). Ofgem have issued various open letters to the industry, in July 2016 and December 2016, asking for views. Instead of launching a full-scale review of charges, Ofgem put the onus back on the industry to suggest solutions by proposing modifications to the industry's Connection and Use of System Code (CUSC). The industry duly put forward two proposals that Ofgem have been considering, and they have decided to implement a modified version of one of them. This would see the level of triad avoidance payment reduced to the level of avoided Grid Supply Point costs. Grid Supply Point costs are the cost of reinforcing the point where the distribution network connects to the transmission network. Generation connected to the distribution network takes demand off the transmission network, so offsets the need for reinforcement. The value of this avoided reinforcement cost is approximately £2/kW.

Reducing the level of triad avoidance payment to the avoided Grid Supply Point costs would take place gradually over three years from 2018 to 2020. In practice, this means a reduction from £45/kW (which was rising each year) to only £2/kW.

Is it such a problem?

Former Energy Secretary Sir Ed Davey has warned that Britain risks "sleepwalking into brownouts and blackouts" as the reduction in embedded benefits could cause many smaller plants to close early and to renege on their Capacity Market contracts. There is a view amongst the smaller generators that the CUSC panel (mainly made up of larger generators) are targeting this one area rather than looking at network charges as a whole, and that this itself could cause distortion in the market to the detriment of smaller generators.

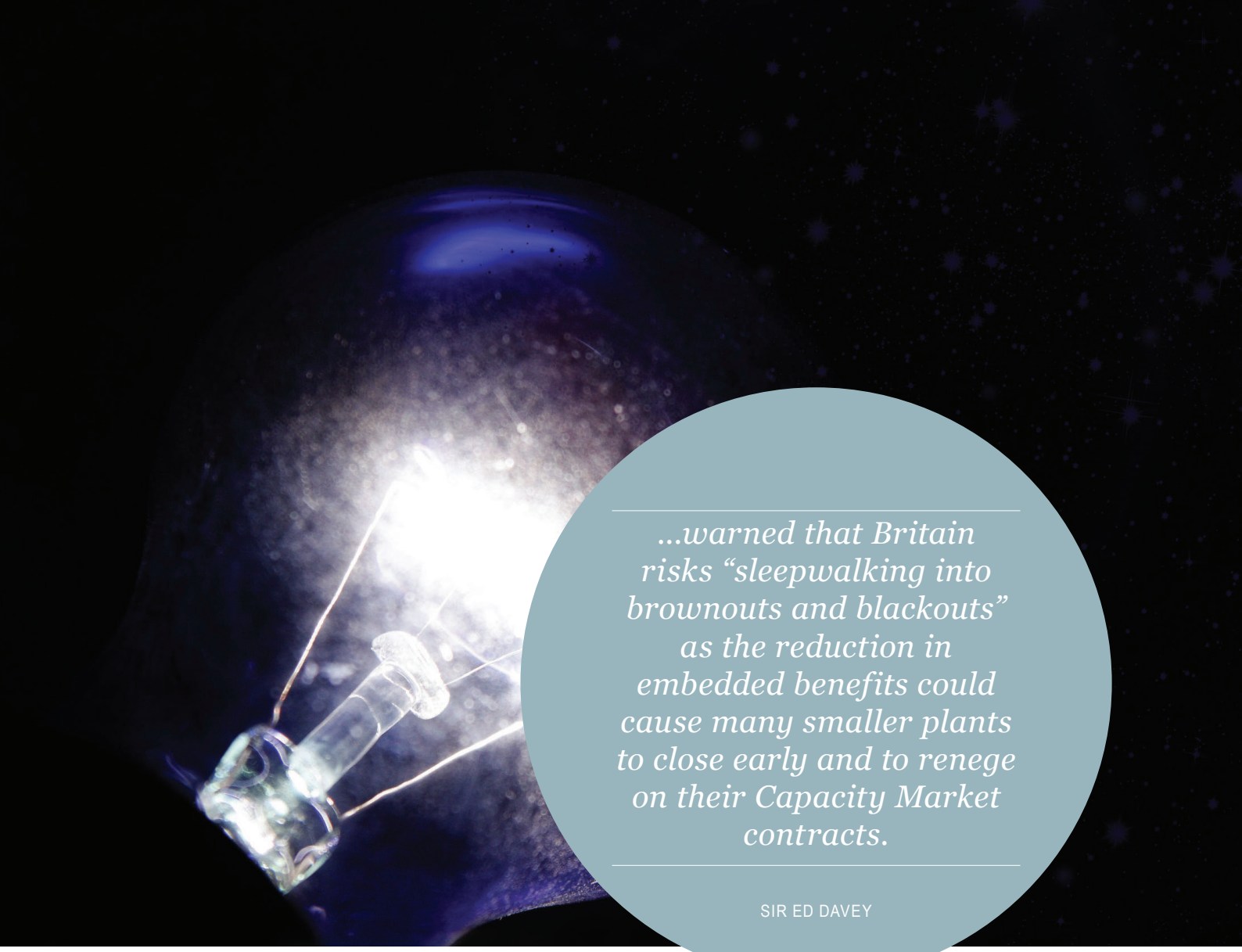
Ofgem's view is that "the proposed reforms would not have a material impact on security of supply" but could potentially save consumers up to £20 per household per year by 2034 and make the energy system more efficient overall.

What does it mean for embedded generators?

Chapter 5 of the consultation looks at the likely effects of the modifications on specific types of generators and is worth a closer look. In summary:

- Thermal generation, including energy consumers with on-site generation (such as hospitals) are likely to see a reduction in revenues if they currently export part of their generated energy. In some cases triad avoidance payments can form up to half of their anticipated revenues and operations. Ofgem "recognise that in some cases, this could lead to a significant challenge to business models or the perceived stranding of assets"
- DSR and storage – reducing the triad avoidance payments may incentivise generation to move 'behind the meter'. This means moving generation beyond the point where electricity consumption is measured (such as a backup generator at a factory) to net off the customer's metered consumption and so reduce their demand charges. Ofgem are considering this as a priority area for the Targeted Charging Review (see below). Some electricity storage projects at distribution level may be reliant on triad avoidance
- payments to be economic. Ofgem don't go into detail as to what this might mean but I think we can read between the lines that it is not good news for storage, and it will be interesting to see the industry responses
- Renewables will be impacted less than dispatchable generation, as they cannot guarantee to generate at triad periods, but anaerobic digestion (AD) plants that prioritise electricity generation over gas production may be particularly impacted, and might prompt them to switch to biogas production, or to export electricity over private wires rather than the distribution network

Ofgem end Chapter 5 with their provisional view that the network charging regime is not the correct place for supporting emerging technologies and that if they need support it should be through direct explicit subsidy to meet a policy aim, rather than through potentially distortive charging arrangements. We are not holding our breath for a new subsidy.



...warned that Britain risks "sleepwalking into brownouts and blackouts" as the reduction in embedded benefits could cause many smaller plants to close early and to renege on their Capacity Market contracts.

SIR ED DAVEY

Targeted charging review

Ofgem also promised to issue a Targeted Charging Review to look at the other embedded benefits and they published it on 13 March. They are consulting on whether to issue a Significant Code Review that will look at changes to the TNUoS and DNUoS residual charges plus changes to embedded benefits (other than the triad avoidance payments).

There is some good news for storage in this. Part of the Targeting Charging Review is looking at how storage is charged and trying to put it on a level playing field with generation, removing the element of double charging that up to now has placed storage at a disadvantage. Ofgem are proposing that this is done via the normal code modification process rather than as part of the Significant Code Review, so that the reforms can be brought about more quickly. See our article Battery Storage: a SWOT analysis for more context on storage.

Next steps

The embedded benefits 'minded to' decision is open for consultation until 9.00am on Wednesday 18 April (an extension from the original closing date of 10 April but over the Easter weekend so not as helpful as may first appear). Ofgem will decide in May whether to proceed with this, or to accept one of the other modifications proposed, or even to reject all the modifications and consider triad avoidance as part of the Targeted Charging Review process instead.

If Ofgem proceed with their decision, triad avoidance charges will start to reduce in April 2018 by a third each year, until by April 2020 they are down to £2/kW.

The Targeted Charging Review consultation is open until 5 May. If Ofgem decide to launch a Significant Code Review, this will take at least 18 months to conclude, then implementation will be after that. That is why Ofgem want the storage charges to be reviewed using the code modification process, which is quicker.

17 October 2017

RENEWABLE ENERGY SOLUTIONS

This article discusses some of the opportunities for occupiers to utilise energy generation and storage technologies co-incidental to occupation of their property assets and, where the property is let, the legal considerations in relation to the lease.

Introduction

Commercial occupiers are increasingly embracing new and evolving energy technologies to streamline and differentiate their businesses as well as cut costs and manage exposure to energy prices. Equally, opportunities are emerging of which occupiers can take advantage. Occupiers need an understanding of both the energy market and incentives, and the interaction with the landlord – tenant relationship, to be able to fully consider the range of opportunities and benefits. This note discusses some of the opportunities for occupiers to utilise energy generation and storage technologies co-incidental to occupation of their property assets and, where the property is let, the legal considerations in relation to the lease.

Use of renewable and other technologies

Benefits

Use of renewable and other low carbon technologies to generate electricity to supplement or substitute electricity imported from the electricity grid is not a recent development; for example solar panels have been seen on the roofs of buildings, both commercial and residential alike, for a number of years. However, despite general falls in the construction costs of renewable energy equipment, the ending of the Government subsidies (Feed-in-Tariff and Renewables Obligation) supporting new onshore wind and solar PV, has resulted in most energy project companies turning their focus to other technologies. Commercial occupiers are not focussed upon harnessing renewable technologies for the purpose of revenue generation but instead identifying where advances in technology can be used to reduce their costs. Commercial occupiers can utilise renewable technologies, in particular solar and wind, to generate electricity for their premises. One of the key challenges to occupiers is the extent to which they are permitted (or otherwise) to install these technologies. This is discussed in more detail below.

Battery Storage

Combined with electricity generation equipment, batteries can be used to store surplus electricity generated at times of heightened generation for use when it is needed. A prime example would be where an intermittent technology is installed such as solar or wind and so generation capacity is affected by weather conditions. Batteries can also be connected to the grid, enabling an occupier to import electricity from the electricity network at night and at other periods of low demand, when prices are typically cheaper. This electricity can be stored and then used during times of higher demand, when it would otherwise cost more to import from the electricity network.

Storing electricity imported during periods of low demand, or after generating a surplus during periods of heightened generation, could also enable an occupier to sell it back on to the electricity network via a licensed electricity supplier when demand on the network increases. This is done by the occupier signing up to provide 'balancing services' to National Grid (e.g. through STOR (Short Term Operating Reserve) contracts or Capacity Agreements). This could generate a profit for the battery storage provider in addition to the electricity cost-saving benefit associated with using stored electricity for operating premises. In order to take advantage of this, the battery would need to be connected to the electricity grid, which requires a connection agreement with the local Distribution Network Operator (DNO).

Connection Agreement

If an occupier wants to connect a battery storage unit or any renewable energy generation unit to the electricity grid, it will need to contact its local DNO to ask for a connection. Each DNO has its own application process, normally available on its website, setting out what information it requires. The installer of the energy project will typically apply on the occupier's behalf. Discussion with the DNO at the outset is crucial, to make sure that the local network has capacity to take the increased load that the installation will create, and to determine what the charge for connection works will be.

Once the DNO has received the application, it must respond with an offer of connection terms as soon as practicable. This will specify the conditions for the connection and the amount of the connection charge. There will be a specified period (typically 30-90 days) to accept the offer. The installer will then carry out the work to install the battery and/or generating unit and connect to the connection works carried out by the DNO. In some circumstances, it may be cost effective to contract with an accredited third party independent connection provider (ICP) to carry out those connection works that do not have to be carried out by the DNO. Again, the installer is likely to guide the occupier through this process.

Property issues

If an occupier wishes to install any of these technologies to serve its premises there are various property issues which it would need to consider. Some of the potential issues are discussed below, but the considerations would vary on a case-by-case basis.

Land requirements

Whether an occupier wants to install solar panels, wind turbines, batteries or other technologies, it needs to be entitled to erect and keep the equipment in its installed location. An occupier may have an internal demise with the roof and external areas retained by the landlord. Even if an occupier has a full structural demise of a unit, there may not be any external areas in the demise which could be used for installing the equipment. This is not fatal however. But the occupier would therefore need to persuade its landlord to agree to allow installation on retained areas. Some landlords are very open to the idea of renewable technology on their property and in some cases this may even be a requirement of the planning permission for the unit or wider estate.

Planning permission

The installation of renewable technologies is likely to require planning permission in addition to the existing planning permission for the premises. It is usual to expect an occupational lease to include a restriction on a tenant applying for planning permission without landlord's consent. As a result, the occupier's landlord may need to be engaged before any application for planning permission is submitted to ensure there is no breach of the lease covenants and to avoid potential for wasted costs in connection with the planning application.

Landlord's consent to alterations

Even if the occupier has, within its demise, the area needed to install the relevant equipment, it is usual to find that an occupational lease will contain a prohibition on structural or external alterations or additions being carried out without landlord's consent. A licence for alterations would need to be applied for and, in practice, this will usually include relevant permissions for the occupier to apply for planning permission for the proposed alterations. Likewise, if the proposed electricity generation equipment requires the installation of cables across the landlord's retained land in order to connect the equipment and/or storage devices to the network it will be necessary to establish whether existing lease rights permit the laying of such cables or whether new rights will need to be sought from the landlord. Once again, the landlord should be engaged early to ensure that the occupier has the required permissions under its lease.

Reinstatement obligations

An occupier carrying out alterations will usually be required to covenant with its landlord to reinstate the premises, removing the alterations, at the end of the term of its occupation. However, the installed equipment may have a residual value to the occupier (who has paid for its installation) or the landlord (if it can compel the occupier to leave the equipment at the premises). A landlord may be interested in the equipment remaining at the premises if the premises have an improved EPC rating by virtue of the equipment or if the landlord otherwise sees a benefit in re-letting the premises with the installed technology. The occupier would not want to forego the residual value.

The landlord and the occupier may therefore want to draw up a pre-installation agreement as to how the equipment is dealt with at the end of the period of occupation where this is due to end before the useful life of the equipment ends and to cover any early forfeiture.

Landlord's consent to underletting

Depending on the proposed arrangements for the installation, ownership and maintenance of the generation/storage equipment it may be that the equipment is intended to remain in the ownership of the supplier/operator, with the occupier simply benefitting from the cost savings in taking power from the onsite equipment rather than from the electricity grid. If this is the case the occupier's lease will need to be checked to establish the requirements for landlord's consent to any such underlease.

Future proofing leases

We have assisted some of our clients in their lease negotiations by including express rights to use roofs and external areas (whether within or outside the demised areas) for installing renewable technology equipment, with the future possibility of such installations in mind. The occupier is in a much better position to negotiate with its landlord to install renewable technologies where it has an underlying right to do so.

Conclusion

There are significant potential benefits to commercial occupiers in adopting renewable technologies and/or battery solutions to enhance their business operations. However there are also several challenges, including investment implications and the entitlement of an occupier to install equipment.

2 June 2017

HYDROGEN: MORE THAN JUST HOT AIR?

Brexit or no Brexit, the UK government is committed under the Climate Change Act 2008 to reducing greenhouse gas emissions by 80% of 1990 levels by 2050. Whilst electricity generation looks on track to achieve this, transport and heat are nowhere near. So government and industry are looking at potentially radical solutions. Could hydrogen be the answer?

The problem

Four-fifths of British households use natural gas for heating and cooking. The burning of fossil fuels accounts for 17% of the UK's emissions in 2015, according to the Committee on Climate Change. These figures need to reduce significantly if the UK is to meet its 2050 emissions targets. Using hydrogen for heating and transport could be a way of achieving this, as hydrogen combustion produces just heat and water, with zero carbon emissions. Producing hydrogen in a low-carbon way is another matter.

Producing hydrogen

There are two main ways of producing hydrogen at scale at the moment and the cheapest is Steam Methane Reforming, or SMR, of natural gas. Converting natural gas to hydrogen using SMR produces carbon dioxide, so it ends up increasing overall CO2 emissions. To make it low-carbon, it needs to be combined with carbon capture and storage (CCS). The CCS industry in Britain has yet to get off the ground, not helped by the government's sudden withdrawal of funding for the CCS commercialisation competition in November 2015, but introducing large-scale hydrogen production for heating should make investors more confident to invest in CCS technology.

The second main way of producing hydrogen is by electrolysis of water, which converts electricity to hydrogen. This is much more expensive than SMR (even with CCS) and requires more energy, but it produces very pure hydrogen. It is also more small-scale than SMR but can have a use to convert and store as hydrogen excess power generated by renewable installations, and to power low emission vehicles – more on this below.

Hydrogen is very versatile as it can be transported as a gas by pipeline, by road in tankers as a compressed gas, or be produced locally in a decentralised system. This means it has many potential uses in an overall energy system.

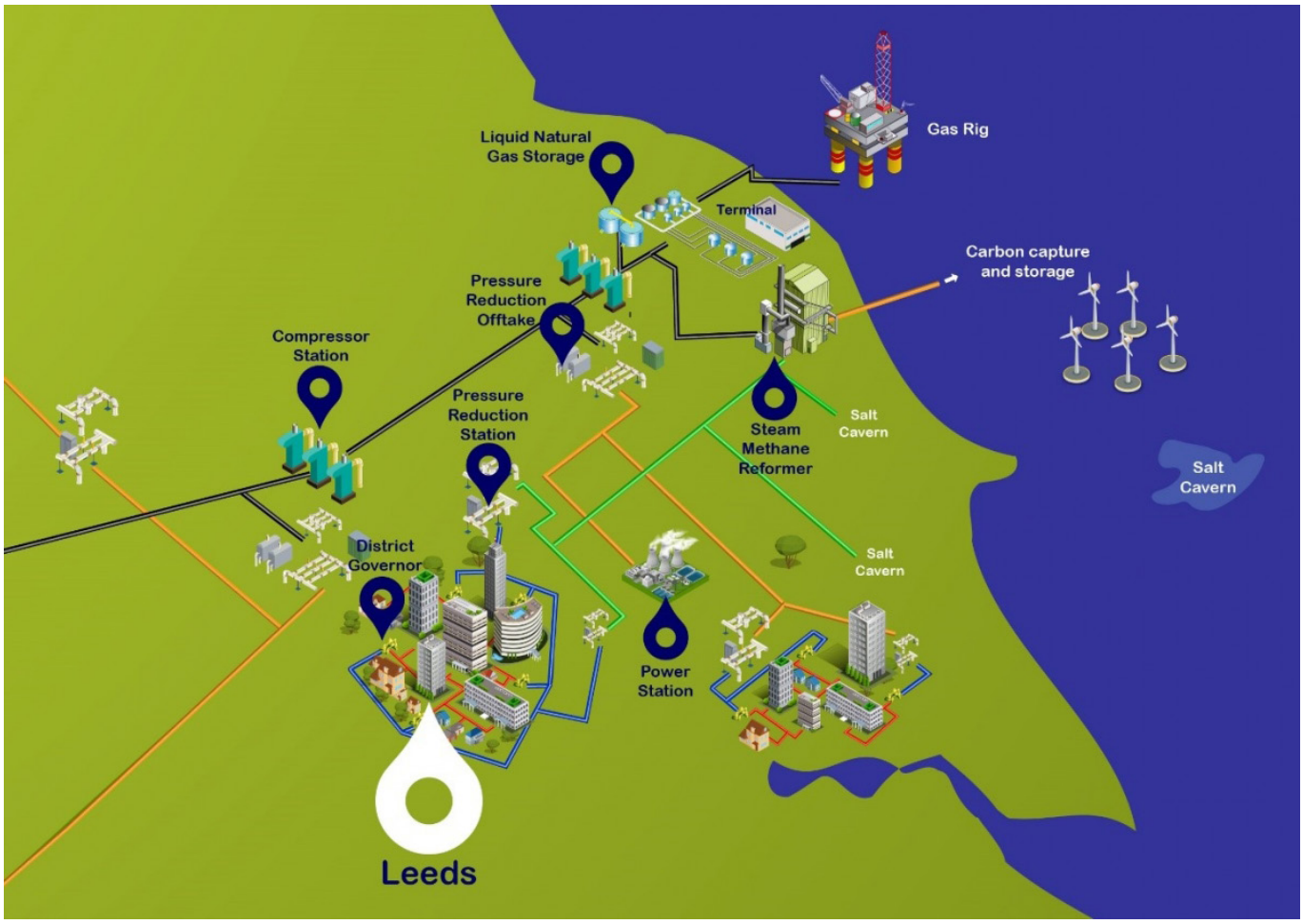
Hydrogen for heat

The number of hydrogen projects that have received Network Innovation Allowance (NIA) and Network Innovation Competition (NIC) funding shows that hydrogen is starting to be taken seriously by the power industry as a decarbonisation option. Perhaps the most high-profile, or at least the most ambitious, project is H21 Leeds Citygate, a proposal to convert the entire city of Leeds to 100% hydrogen, fuelled by four SMR reactors on Teeside and with CCS and excess hydrogen storage in salt caverns under the North Sea. Led by Northern Gas Networks (NGN), the project study concluded that "converting the UK's gas network to hydrogen is technically possible and economically viable" and that it would lead to a 73% reduction in CO2 emissions from heat but also from transport and power generation.

The next stage is to prove that hydrogen is safe to use in the domestic gas distribution network, and NGN have applied (and passed the initial screening) for NIC funding to do this. They are also looking at extending their network analysis of Leeds to other cities across the UK, working with other gas distributors.

Four-fifths of British households use natural gas for heating and cooking

The Leeds H21 project



©Northern Gas Networks - to read more about H21, visit Norther Gas Networks' website www.northernetworks.co.uk.

Other current projects include:

100% Hydrogen – a Scotia Gas Networks NIA project to research and evaluate the feasibility of constructing and demonstrating a 100% hydrogen distribution network.

HyDeploy – a consortium led by National Grid plc and NGN is carrying out a three-year NIC-funded trial of injecting a blend of natural gas and hydrogen into Keele University's private gas distribution network, involving building a hydrogen production plant and injection system at the university. Regulations only permit 0.1%vol of hydrogen in the UK gas network, but using Keele's private network, NGN will be able to trial injection of up to 20% hydrogen.

BEIS – are setting up a three year innovation programme with £25 million funding to de-risk and demonstrate the use of hydrogen for heat in UK homes and businesses, which will inform future policy development.

Hydrogen supporting renewable electricity

The process of electrolysis converts electricity to hydrogen gas. Although not as efficient as SMR, it can be a way of producing "green" hydrogen if renewable electricity is used. There are times, such as windy nights, when the output of renewable energy is higher than the demand for electricity. Using electrolysis at such times can be a way of storing renewable energy as hydrogen gas and avoiding grid constraints. The hydrogen gas can then be used to meet periods of increased electricity demand, by converting it back into electricity using fuel cell technology.

The 'Surf 'n' Turf' project in Orkney is a good example, where surplus electricity generated by tidal power and an onshore wind turbine is converted to hydrogen by a 500kW electrolyser. The hydrogen is stored as compressed gas then transported on a trailer by road and sea to Kirkwall, where it powers a fuel cell to generate clean electricity on demand. This is being extended using European funding so that the hydrogen will also be used to refuel a fleet of ten vans and two hydrogen-powered boilers to provide zero carbon heat.

Hydrogen for transport

The transport sector seriously needs to decarbonise. Last year the proportion of renewable energy used in transport actually fell from 4.9% to 4.2%. Air pollution is also in the news, with NOx emissions from diesel cars being a particular issue. Electric vehicles have been lauded as the solution, but they are not the only solution as they bring their own problems for the electricity grid. There are various horror stories such as a brownout if six cars on the same street plug in to charge at the same time, and threats of costly grid reinforcement being needed if there is significant consumer take-up.

The Vehicle Technology and Aviation Bill attempts to alleviate this by introducing a power to mandate smart charge points (see our article, Modern Transport Bill boosts electric and hydrogen vehicles) but hydrogen-powered vehicles could complement, rather than compete with, the demand for power.

Hydrogen fuel cell electric vehicles (FCEVs) can be refuelled in around five minutes using a pump like a conventional petrol or diesel car and have a range of around 300 miles and have zero emissions. Toyota, Honda and Hyundai have started mass-producing FCEVs, but take up has so far been low, partly due to the cost (which will come down given they are starting to be mass-produced) but mainly due to the "chicken and egg" lack of hydrogen refuelling infrastructure. Recently the Department for Transport launched a £23 million fund to boost the creation of hydrogen fuel infrastructure and boost the uptake of hydrogen-powered vehicles; and Shell opened its first hydrogen vehicle refuelling station in the UK at Cobham on the M25 in February 2017.

The real opportunity for growth of FCEVs is in freight and public transport, where the weight of them is too great for electric battery power alone. Aberdeen, for example, has a fleet of ten hydrogen fuel cell buses which are fuelled by hydrogen produced by electrolysis on site. The world's first "Hydrail", a hydrogen-powered train, was tested successfully in Germany in March 2017, with the first operational trains being rolled out by 2018.

Should the natural gas network be converted to hydrogen, then this would enable a network of hydrogen refuelling stations to be built, connected to the hydrogen gas network, and would get rid of the "chicken and egg" scenario, allowing the power and fuel network to work together.

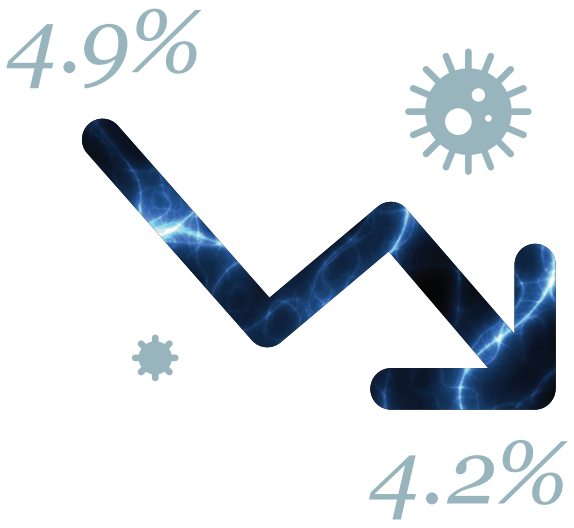
Conclusions

Replacing natural gas with hydrogen seems a radical option, but maybe not that radical when compared with other future scenarios that envisage a wholesale conversion to electricity and decommissioning of the gas grid (see KPMG's 2050 Energy Scenarios). It will only enable us to meet our carbon reduction commitments if the hydrogen is produced in a low-carbon way. This means using renewable electricity to power electrolysers, or using SMR coupled with CCS. If there is a need to produce hydrogen at scale then this could be a real boost to the CCS industry as it would become a safer bet for investors.

In reality, without a very clear policy direction and mandate from government, hydrogen is likely to develop as part of a portfolio of low-carbon energy options. Freight and passenger transport companies may well use hydrogen to power their fleets, and could produce that hydrogen on-site, and there could be a number of stand-alone hydrogen networks, like the SGN 100% Hydrogen pilot.

Rather than a wholesale replacement of natural gas with hydrogen, which would necessitate replacing all appliances, we could see regulations being relaxed allowing an increased proportion of hydrogen to be injected into the gas network, although this is probably not a long term solution to reducing carbon emissions, and brings its own problems of how to meter this, given that the energy content of hydrogen is lower than that of natural gas.

What is clear is that the energy industry are taking hydrogen seriously and it is now up to the next government to introduce the policies needed to encourage its wider adoption.



The transport sector seriously needs to decarbonise. Last year the proportion of renewable energy used in transport actually fell from 4.9% to 4.2%

23 August 2016

BATTERY STORAGE: A SWOT ANALYSIS

"Electricity storage is widely regarded to be the single most important technological breakthrough likely to happen over the period to 2030 and a complete 'game changer' in the way that the power system operates".

So says a recent report by Energy UK, Pathways for the GB Electricity Sector to 2030.

The ability to store energy at scale will revolutionise how the electricity grid works. Instead of relying on baseload power, which can be ramped up at times of peak demand, there is a move to power being generated closer to where it is used, and stored when not needed. The evolution of storage technologies, including battery storage, is expected to take off in the next few years and is now on the verge of being able to compete with traditional power stations for some of the services they provide. We look at the strengths, weaknesses, opportunities and threats that this involves.

Strengths

- Avoids network reinforcement
- Alleviates constraints
- Helps balance the system
- Complements intermittent renewables
- Variety technologies/uses
- Range of potential sources of revenue
- Costs reducing rapidly

Weaknesses

- Regulation
- Cost
- Overlapping/complicated range of revenue sources
- Current markets do not match benefits that storage can offer

Opportunities

- Next 5-10 years
- Enhanced frequency response
- Capacity market
- Time of Use tariffs
- Regulatory reform
- New markets
- Aggregators
- DSOs

Threats

- Embedded benefits review
- Technology risk
- Capacity market
- Electric cars

Strengths

The main strengths of battery storage are in the range of services it can offer to the electricity network as a whole.

Avoids network reinforcement: Using battery storage in conjunction with generation means that at times when generation outstrips demand, instead of the excess energy flowing along the distribution or transmission network, it can be captured and stored, to be released when needed. As more "embedded generation" (generators connected to the distribution, rather than the transmission, network) comes online, some distribution networks cannot cope with the extra demand placed on them and storage can help avoid or at least delay the need for expensive network reinforcement.

Alleviates constraints: At times when supply outstrips demand, such as on windy nights, wind turbine operators are paid to shut down. The ability to store excess energy reduces the need for such constraint payments.

Helps balance the system: Battery storage in particular can absorb from or discharge electricity to the network at a fraction of a second's notice.

Complements intermittent renewables: With the addition of energy storage, solar and wind power become more akin to traditional fossil fuel-based "baseload" generators, making total decarbonisation of energy a more realistic prospect.

Variety of technologies/uses: There are many different types of battery storage technologies in development and the UK government is keen to support research into new technologies.

Range of potential sources of revenue: Battery storage can participate in a number of ancillary services for National Grid such as Enhanced Frequency Response, Firm Frequency Response (for larger systems) or reserve services such as STOR or the Capacity Market.

Costs reducing rapidly: The cost of battery storage is predicted to fall below $100 per kWh by some point in the 2020s, at which point it will be competitive with more traditional sources of power and able to be rolled out on a commercial scale.

Weaknesses

The main weaknesses of storage are how it is regulated and what markets there are for the services it can provide.

Regulation: Because storage is so new, the system of regulating it, based on the Electricity Act 1989, has not caught up. The 1989 Act did not contemplate storage and so it has had to be classed as a form of generation and/or an end user.

As a form of generation, a battery storage facility will need to be licensed and therefore comply with the various Grid Codes – an administrative headache – unless it is small enough to fall within an exemption.

It also means that, because of EU "unbundling" rules, DNOs and electricity suppliers cannot own storage assets, which is hindering the development of "smart grids".

If it is classed as an end user, the owner of a storage asset is charged the Climate Change Levy (CCL) on the electricity going into and coming out of the battery – so is double-charged. HMRC would need to assess each project on a case-by-case basis to decide if it is classed as an end user or not.

Cost: Battery storage is still expensive compared to other power generation/grid balancing services at the moment, and it is also very capital-extensive, requiring a large up-front cost that may put investors off.

Overlapping/complicated range of revenue sources: Although one of the strengths of storage is the range of potential sources of revenue open to it, this is also one of its weaknesses as those revenue streams are not easily aligned. For instance, the tender dates and technical specifications for the various response services and reserve services are all different, making it difficult to access a number of them at the same time.

Current markets do not match benefits that storage can offer: Although (as mentioned in Strengths) storage can help to avoid or delay investments in distribution infrastructure, at the moment there is no reward available for this. Similarly, storage is unable to bid for a Contract for Difference, either on its own or in conjunction with a renewable power generator such as a wind farm.

Opportunities

There are many opportunities for battery storage.

Next 5-10 years: All industry commentators, and the National Infrastructure Commission in the UK, seem to agree that electricity storage is due to take off in the next 5-10 years. The merger of Tesla (manufacturer of electric cars and the Powerwall domestic battery) with SolarCity, the biggest rooftop solar provider in the US, is the sign of things to come, when storage and renewable energy will go hand in hand.

Enhanced Frequency Response: This new service from National Grid is aimed predominantly at storage assets that can provide frequency response in one second or less. The first tender, for around 200MW, took place in July 2016 and attracted interest from 1.3GW of power, nearly 70% of which was battery storage projects.

Capacity Market: Recent reforms have lowered the threshold for participation to 500kW, which should enable smaller projects to participate in their own right rather than having to go through an aggregator, but no new battery storage project received a capacity contract in the last auction and the clearing price (£19/kW last time) is likely to be too low to fund a new project, given the high up front costs involved.

Time of Use tariffs: Once these are more widely introduced from 2017, there will be more incentive to use "behind the meter" storage, so that energy users can use batteries to draw from the grid at cheap times and use the stored energy at the times of highest demand – and prices.

Regulatory reform: The National Infrastructure Commission in its report Smart Power recommended that DECC and Ofgem review the regulatory and legal status of storage to enable it to compete fairly with generation. The Government has said it will set out proposals for reform by Spring 2017.

New markets: Ofgem is looking at ways to make the ancillary services market more transparent, to increase participation from new entrants and new technologies. This should help to address the weakness identified above, that there is an overlapping/complicated range of revenue sources that is not easy to access.

Aggregators: For smaller battery storage systems and/or those new to the market, using an aggregator service can help to access some of the ancillary services and reserve services available.

DSOs: As the UK moves towards a "smart grid" and away from the traditional model of transmission-connected generation and distribution-connected consumers, there is arguably a need for distribution network operators (DNOs) to have more control over the power passing through their network, especially since it often flows both ways due to the increase in "embedded generation" connected to the distribution network. The NIC Smart Power report recommended that the transition to more actively managed local networks (effectively distribution system operators or DSOs) be a government priority. This would mean a much greater role for local storage systems in helping to manage the local network.

Threats

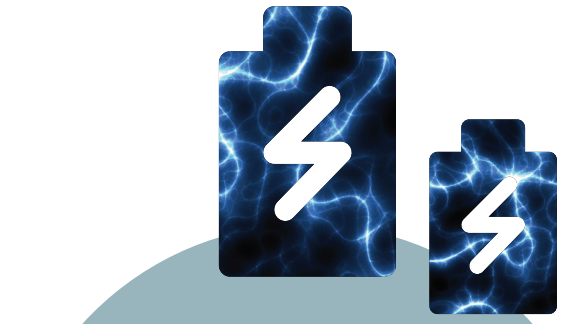
There are some threats that battery storage providers need to be aware of.

Embedded benefits review: Generators that are connected to the distribution, rather than the transmission, network get a range of benefits including not having to pay TNUoS charges (to use the transmission network) and in fact get a "triad avoidance" payment from suppliers for being able to generate surplus power at times of peak demand that gets exported onto the transmission network and in effect reduces the demand on the transmission network. Battery storage plants will be classed as embedded generation if they discharge surplus power at peak times. Ofgem are consulting on removing these benefits to ensure a level playing field for all generators.

See our article on Embedded Benefits for more detail.

Technology risk: As many of the battery technologies are still being developed and tested, there is a risk that they will not perform as specified, but this should reduce over time.

Electric cars: These can compete, at least in the domestic "behind the meter" market, with other battery storage providers like Powerwall or Moixa as there is a battery in the car which can discharge electricity back to the grid and potentially make money by doing so. It may be that they become the main market for domestic-sized battery systems so that other types of battery storage will have to concentrate on larger-scale installations.



The evolution of storage technologies, including battery storage, is expected to take off in the next few years...

2 November 2016

DECENTRALISED ENERGY SCHEMES – WHAT'S ALL THE FUSS ABOUT?

Decentralised energy schemes are nothing new, but they are becoming a much more prominent consideration for developers. Find out how to address some of the key issues and challenges.

- Planning conditions are increasingly requiring the use of decentralised energy schemes;
- Developers will need to factor these schemes into their wider development planning;
- How to address some of the key issues and challenges.

What's it about?

Decentralised energy schemes are nothing new, but they are becoming a much more prominent consideration for developers. The schemes come in all shapes and sizes; involving combined heat and power (CHP), district heating and cooling, waste to energy and/or renewables such as ground source or air source heat pumps, and serving one large single commercial entity, entire communities, multiple residential customers or any combination in between. However they all have one common theme; that the energy is generated entirely or partially off the main grid.

Mitigating the effects of climate change, improving energy security and driving down the cost of energy (both economic and social) is an increasingly important issue for policy makers on a global, European and national stage. Decentralised schemes are seen to be part of the solution as they can provide cost-efficient energy using more sustainable technologies and improve energy security.

Why does it matter?

Including such a scheme within their development planning was not something a developer would need to have in mind previously unless it specifically wanted to.

However, local authorities have altered the way they use their planning powers with many now expecting developments to contain some renewable or sustainable generation. The London Plan, for example, has an expectation that 25 percent of the heat and power used in London will be generated through the use of localised decentralised energy systems by 2025 and so it requires boroughs to develop proposals to establish decentralised energy networks, requiring developers to prioritise connection to existing or planned decentralised energy networks where feasible.

Whilst there are challenges in delivering these types of schemes, businesses are seeing the benefits they can bring in terms of achieving environmental standards such as the Code for Sustainable Homes and BREEAM, plus more energy efficiency and lower carbon emissions. Some are going further and setting up their own Energy Services Company (ESCos) to run the schemes thereby providing an additional revenue stream.

Now what?

Some issues to look out for include:

- ensuring that the local planning authority does not prejudice wider development imperatives in setting decentralised energy planning conditions
- complex issues around requiring tenants (especially vulnerable/social housing tenants) to take heat and/ orelectricity from the ESCo
- how best to deal with counterparty risk, both in terms of the ability to pay and ssurance that there will be long term demand
- convincing tenants that supply is reliable and cost efficient and ensuring system resilience without costly overengineering
- synchronisation between the development of the network and capacity reservation

Some further challenges new developments face will be because they are connecting in to older schemes which, sometimes, were not designed with expansion in mind. That creates technical and practical issues such as the ability to lay pipes and cables and reduced efficiency where the energy centre is sited far from the demand with the result that heat is either lost or unusable. However a well-designed scheme can be more environmentally sustainable and more cost efficient than using conventional gas or electricity, can provide long term energy security to tenants and also offer investors an attractive long term investment opportunity.

For individual properties and concentrated multiple occupation schemes, developers should not ignore ground source and air source heat pumps. Air source is now very affordable with negligible space and infrastructure requirements and produces a very low running cost, as well as attracting a Renewable Heat Incentive contribution that will more or less cover the capital cost over about 8 years.

WHO TO CONTACT

Richard Goodfellow
Partner - Head of Energy and Utilities

+44 (0)113 209 2405
richard.goodfellow@addleshawgoddard.com

Paul Dight
Partner - Energy and Utilities

+44 (0)113 209 7704
paul.dight@addleshawgoddard.com

Paul Minto
Partner - Energy and Utilities

+44 (0)1131 222 9594
paul.minto@addleshawgoddard.com

Guy Winter
Partner - Energy, Corporate

+44 (0)207 160 3024
guy.winter@addleshawgoddard.com

Angus Rollo
Partner - Energy, Corporate

+44 (0)20 160 3291
angus.rollo@addleshawgoddard.com

Simon Courie
Partner - Energy and Utilities

+44 (0)207 160 3110
simon.courie@addleshawgoddard.com

Peter Mason
Partner - Energy, Real Estate

+44 (0)113 209 7681
peter.mason@addleshawgoddard.com

Oliver Carruthers
Partner - Energy, Project Finance

+44 (0)20 7160 3367
oliver.carruthers@addleshawgoddard.com

John Emerton
Partner - Energy, Disputes (Construction)

+44 (0)113 209 2545
john.emerton@addleshawgoddard.com

David Shaw
Partner - Co-Head of Water

+44 (0)113 209 2319
david.shaw@addleshawgoddard.com

James Reynolds
Partner - Head of Nuclear

+44 (0)113 209 2626
james.reynolds@addleshawgoddard.com

Simon Kamstra
Partner - Energy, Disputes

+44 (0)113 209 2356
simon.kamstra@addleshawgoddard.com

Sara Gilmore
Legal Director - Infrastucture Projects and Energy

+44 (0)113 09 2415
sara.gilmore@addleshawgoddard.com

Alex Clayton
Managing Associate - Infrastucture Projects and Energy

+44 (0)113 209 2280
alex.clayton@addleshawgoddard.com

Anna Sweeney
Senior Knowledge Lawyer - Infrastucture Projects and Energy

+44 (0)113 209 2015
anna.sweeney@addleshawgoddard.com

NOTES

addleshawgoddard.com

Aberdeen, Doha, Dubai, Edinburgh, Glasgow, Hong Kong, Leeds, London, Manchester, Muscat, Singapore and Tokyo*

* a formal alliance with Hashidate Law Office

REF: 12217