2018: The Year of Living Dangerously
An Energy Spectrum Review
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With 2018 now having drawn to a close, the year saw another busy period in energy market activity and regulation, against the looming backdrop of Brexit. This annual overview attempts to capture the highlights and main developments.

But, as we move into 2019, when we look over our shoulder we perceive a year of limited progress and missed opportunities.

**Signs**

We observe three dominating but perhaps contradictory themes:

- regulatory action has adhered to short-term economic regulatory objectives, but it remains poorly coordinated with longer-term policy objectives
- government has defaulted to big, showpiece policy announcements as compensation for delays in strategic policy-making, and
- inconsistency has been revealed in sharp relief between a stated desire for market-based solutions, when intervention itself is undermining markets.

Let me look at each of these themes in turn, before considering at a high-level some implications for 2019.

**The expendables**

During 2018 Ofgem muscularly continued to prioritise addressing detriment to the consumer interest. We saw this through its tough approach to implementing the default tariff cap – although this was also driven by government - and parallel workstreams to nudge customers to engage with the market. There have also been the firming up of significant proposed reforms to network charges through the Targeted Charging Review (TCR), which has become anything but “targeted”, and also to network regulation through preparations for RIIO-2.

Many of the diagnoses Ofgem has made are reasonable. But the technocratic approach to shaping solutions and a long continuum of change have left many market participants picking up the practical consequences. Some of these interventions have produced both intended and unintended winners and losers. In some important instances, intervention has occurred late or to correct for previous actions that have not delivered the desired objectives. An example here is the belated action to tighten up supplier licensing, but only after multiple supplier failures, and despite Ofgem failing to intervene earlier even though it had signalled its intention to do so.

Furthermore, a lack of coordination within government has resulted in interventions that we believe could imperil long-term policy aims. The domestic retail market is a notable casualty. As we end the year, the extended price cap is already beginning to affect pricing and dilute incentives to innovate. The narrative is still about competition and principles-based regulation, but levels of regulatory activity prescribing what suppliers can and cannot do continue to increase.

And as for the cap being a temporary intervention, few appear to really believe this, and Ofgem has already kicked off debate on what interventions will be needed after the current pricing restrictions are removed at some point between 2020 and 2023.
Maverick

In the course of the year, aside from the default tariff cap, substantive government activity has been surprisingly limited given the platform provided in 2017 by both the *Clean Growth Strategy* and the *Industrial Strategy*.

The request from Energy and Climate Change Minister Claire Perry in April 2018 and reiterated in October that she receives advice from the Committee on Climate Change (CCC) on how to achieve a net-zero carbon position is significant. But it has yet to lead to any increase in the level of policy ambition or any new mechanisms to deliver it. Indeed, there remain concerns among stakeholders that the fourth and fifth carbon budgets are unlikely to be met.

In power, despite considerable progress, the CCC still recommends that greater proactivity in policy is required to remain on track. The government confirmed that a third Contract for Difference (CfD) allocation round will be run in May 2019, but those anticipating long-term certainty on carbon pricing beyond 2021 will be disappointed. The five-year review of the Electricity Market Review (EMR) package also looks like it may be an exercise in rearranging the deck chairs.

Business Secretary Greg Clark’s high-profile speech in November proclaimed (prematurely in our view) the end of the trilemma. Positioned as a response to the Helm Review, it had an overall tenor of business as usual and technical enhancement rather than a shift to the more radical vision proposed by Helm. It was yet another high-level statement that failed to convince, deferring critical questions facing the sector for an Energy White Paper likely to follow in 2019. Four new principles were set out, including the primacy of markets, and the need to maintain optionality and agility. But it all seemed to us to highlight their absence rather than their imminence.

In Carbon Capture Usage and Storage (CCUS), the policy has barely left the blocks. The action plan published in November treads water. After nearly a decade of policy focus in this area with a few false starts, we are back to conceptual debate on incentive design and a horizon to the 2030s before government thinks CCUS will be deployable at scale.

In transport, the government had positioned the July *Road to Zero strategy* as its flagship prospectus for accelerated emissions reduction. However, the strategy disappointed many, including the CCC, in the level, target date and firmness of its ambition to phase out conventional vehicles and its vagueness in defining Ultra Low Emission Vehicles.

In heat, emissions reduction has also failed to build momentum and in 2018 only limited foundations have been laid for further progress. In August, government confirmed that ECO3 will proceed, and a revised scheme focused exclusively on affordable warmth is now in place. But the tenor of stakeholder comment generally is that the expectation levels set last year in the *Clean Growth Strategy* have yet to be translated into specific measures or a coherent programme, and that the government response in December response to its *Call for Evidence* on heat in March is unlikely to result in a robust framework for development being established.
Lethal weapon

There is a growing paradox in the market-place: continuing interventions to address market distortions and finesse the market-based energy system but which are increasingly undermining incentives to invest.

The gas market remains relatively untouched by policy intervention, and it held up well despite the extreme circumstances that occurred with the Beast from the East in March. Strategic storage remains an intervention too far, it seems, despite the loss of Rough and our increasing reliance on LNG cargoes and our neighbours at peak times.

This is in stark contrast to power, where markets are riddled with intervention and peak power pricing reached a milestone with the final stage of implementation of P305 electricity cash-out reform in November. Both the CfD mechanism and Capacity Market (CM) continue to be prone to tinkering. The RO and FiTs have been removed but the playing field is far from level given the winners already picked. Hinkley Point C remains on the distant horizon, but a year on other nuclear projects have faltered.

The Carbon Price Support (CPS) is now driving a wedge with Europe with the result that the total carbon price looks like it will be over-egged given the resurgence in the EU Emissions Trading Scheme (ETS). The suggestion by the Chancellor in the Budget that CPS might have to be cut well illustrates that consumer pricing impacts are now a stronger driver of policy than carbon pricing.

At the same time new sizeable investment in gas-fired generation remains in stasis with RWE’s Tilbury being the latest large project to stall. Significant coal generation remains on the system despite a policy commitment to remove unabated capacity by 2025, but – the one big success story – offshore wind continues to boom supported by CfDs.

But 2018 is the year in which it became clearer that the sheer scale of subsidised renewables emerging onto the system will see price cannibalisation grow, making it harder for unsubsidised projects to succeed. Meanwhile, the government seems to have reached a crossroads adhering to the position that there will be no new subsidies, and that both further new nuclear build and CCUS development will be dependent on significant cost reductions that many feel are unlikely to materialise.

Regionally, flexibility markets run by Distribution System Operators (DSOs) rather than Distribution Network Operators (DNOs), required to accommodate localised renewable generation, are emerging slowly. The DNOs have published strategies and engaged in initiatives, and the Open Networks project is coralling relatively uniform levels of commitment. But, we are still some way from genuine DSOs providing a new demand stimulus to the smart, flexible transition that the government says it wants.

To cap it all, the government faced the black-swan late in the year of the withdrawal of State Aid approval of the CM, which could test the ability of sharper price signals to ensure security of supply. New technologies focussed around storage and the demand side are stepping forward. This is despite market rules and commercial opportunities remaining in flux, and they do not yet provide a stable or facilitating framework. BEIS tried hard as the year drew to a close to settle nerves, and to reassure operators and developers that the CM "standstill" would be a short one. The resulting level of uncertainty in the market-place is higher than it has been for decades, creating an environment in which investment decisions have become extremely challenging and in which investor confidence has plummeted.
Apocalypto

The positive news is that no government can let this position last for long, or the lack of confidence will become a significant drag on investment and enterprise. If a net-zero target is a serious ambition, the government will need a vibrant pipeline, innovative solutions and confident investors – Brexit or no Brexit.

As a result, 2019 could be the year in which government re-asserts a strategic grip over the energy policy agenda, simply because it has no other choice. It will be compelled to focus away from the retail market. A policy paper is said to be imminent, preparing the way for the White Paper.

We think success will depend on development of a shared suite of strategic objectives between Ofgem, BEIS and other key stakeholders, something we have been arguing for several years. We welcome the further review of industry governance trailed by Greg Clark in his response to Helm. The focus on a wider reform of regulation proposed by the Chancellor in the Budget could also reinforce the need for change.

Against this, the ability of our politicians to control these events is likely to be greatly diminished if economic circumstances, as looks likely, harden and the political map changes. A hard or soft Brexit and any transitional pathway to this outcome will also be a key driver of the decisions that will need to be taken.

One of the very few things we do know is that 2019 is likely to be a landmark, but to what it is hard to say.

We at Cornwall Insight will be analysing every aspect of these themes and the supporting narratives as they unfold, and will continue to bring you independent, trusted perspectives just as we have done for the last 14 years.

From myself and all the Cornwall Insight team, I wish you all the best for a happy and peaceful 2019.

Gareth Miller CEO
Energy Policy in 2018: Flattering to deceive

Policy headlines from 2018

- Signs of faltering progress under Climate Change Act
- Clean Growth Strategy one year on, with important delivery gaps remaining
- Increasing focus on possible adoption of a net-zero carbon target, despite problems with the fourth and fifth carbon budgets
- Clark responds to Helm Review outlining four principles for the power sector, promising an early Energy Policy White Paper
- EMR five-year review progresses
- Latest CM auctions see record low prices, but CM presently suspended pending reapplication for State Aid clearance
- £60mn announced for third CfD auction
- ECO3 implemented, refocusing on fuel poverty
- FiT export tariff closure announced
- New Road to Zero transport strategy criticised for lacking ambition as heat strategy also continues to lag

Energy policy in 2018 was set against a backdrop of celebration of reaching the 10th anniversary of implementation of the Climate Change Act 2008. But, despite Greg Clark announcing the end of the trilemma, over the course of the year there have been mounting concerns about the UK’s ability to meet the fourth and fifth carbon budgets. There have also been increasingly loud calls for a net-zero carbon target.

1.1 Mixed scorecard

There has been a discordant dialogue developing between BEIS and the Climate Change Committee. The committee had already criticised the level of detail in the October 2017 Clean Growth Strategy, and in January, while it had commended the ambition the government’s ambition, it found few new detailed policies to reduce UK emissions into the next decade and beyond.

Minister of State for Energy and Climate Change Claire Perry was somewhat dismissive in turn in response to its assessment of the strategy. The committee projected shortfall against the fourth and fifth budgets is around 10Mt, but Perry responded that this was less than 1% of each budget, and she noted the committee itself had welcomed the level of ambition in the strategy. This conversation about whether we remain on track or not with regard to emissions reduction has recurred throughout the year.

In June the committee published its 10th progress report. It continued to be critical of the gaps and the lack of specific or measurable policies. The report set out four key messages to the government to “put emissions reductions on track, based on the lessons of the last decade”: 
support the simple, low-cost options such as on-shore wind and home insulation. “Worries over the short-term cost of these options are misguided”, it noted

- commit to effective regulation and strict enforcement
- end the chopping and changing of policy, noting important programmes had been cancelled in recent years at short notice, including Zero Carbon Homes and the second Carbon Capture and Storage (CCS) Commercialisation Programme, and
- act now to keep long-term options open. Key technologies should be pulled through to bring down costs and support the growth of the low-carbon goods and services sector.

The committee also set out a list of critical commitments it expected the government to deliver by the time it issues its next progress report to Parliament in June 2019. These included actions required by the end of 2018 such as concrete policies to secure improvements in residential energy efficiency, a deployment pathway for CCS and new policy to strengthen the incentives for people to buy electric vehicles.

Committee Chairman Lord Deben said the government’s progress was “just not good enough”. He added “The fact is that we are off track to meet our own emissions targets in the 2020s and 2030s. We now have to ensure that the government learns from this experience and presents a programme to tackle emissions right across the economy […] to prepare to fulfil the obligations of the Paris Agreement.”

1.2 Clean Growth Strategy one year on

Claire Perry hit back again in an update on the *Clean Growth Strategy* one year on published in October to coincide with the first Green GB Week, explaining “how we are developing our policies and proposals”.

Progress had been made in many areas including:

- announcing new auctions to deliver between 1-2GW of offshore wind each year in the 2020s, with total support of up to £557mn
- measures to at least halve the energy use of new buildings by 2030 and the introduction of the first green mortgage
- publication of the 25-year Environment Plan
- the [belated] publication of the *Road to Zero Strategy*, and
- committing £5.8bn to climate finance from 2016 to 2021.

Perry said in conclusion that the government believed the UK would need to legislate for a net-zero emissions target, and she asked the committee to provide advice on the implications of the Paris Agreement for the UK’s long-term targets.
1.3 Road to Zero Strategy

In early July, the government published its long-awaited Road to Zero Strategy, outlining measures to progress decarbonisation for the transport sector. Its 46 policies centred around addressing anxieties around up-front costs, vehicle range, and charge-point access within the objectives to:

- have at least 50%, and up to 70%, of new car sales be ultra-low emissions by 2030
- end the sale of new conventional petrol and diesel cars and vans by 2040, and
- have “almost every car and van” zero emissions by 2050.

These priorities were reflected in the overall vision for a legally-binding 15-year strategy to double low-carbon fuel use reaching 7% of road transport fuel by 2032. Although action on climate change is a driving force behind the strategy at a national level, much local authority and other stakeholder activity around EVs has also been driven by concerns over air quality issues.

A supporting package included investments of £1.5bn, including a £400mn charging infrastructure investment fund, increased R&D funding and tax allowances and support for local planning policies to enhance EV uptake.

But the government’s immediate cuts to grants for consumers buying new Category 1 (full battery electric vehicles) and their removal for Category 2 and 3 (hybrid vehicles) captured a lot of criticism. And the CCC in its response was disappointed in the level, target date and firmness of its ambition to phase out conventional vehicles and its vagueness in defining Ultra Low Emission Vehicles, labelling the strategy as “a missed opportunity”.

Insight Paper 1

In June, we issued our paper Electric Vehicles: Driven to Disruption.

The paper presented six archetypes for EV-related product offerings by suppliers, and it set out a series of recommendations for regulatory rule changes to support them. We concluded that the need for regulatory and policy clarity to accommodate electricity supply offerings tied to EVs grows with the sophistication and complexity of offerings.

1.4 Clark responds to Helm review

Another landmark was reached on 15 November, when BEIS Secretary Greg Clark responded to the Helm Cost of Energy Review recommendations from autumn 2017 to streamline the energy sector. Helm’s wide-ranging and quite radical recommendations had included:
• unification of CM, FiT and CfD auctions
• gradual reform of FiT and CfD to transition to eventual abolition
• further enhancements to competition in wholesale and balancing markets
• a default supply tariff should be required, with the margins published, and
• carbon prices and energy taxes should be harmonised.

In the high-profile speech, After the Trilemma: Four Principles for the Power Sector, the Secretary of State set out the government’s new vision for the energy sector based on four new principles. These are: the market principle – market mechanisms should be used to take full advantage of innovation and competition; the insurance principle – given future uncertainty, government must be prepared to intervene to provide insurance and preserve optionality; the agility principle – energy regulation must be agile and responsive to take advantage of the smart, digital economy; and the “no free-riding principle”: all consumers of should pay a fair share of system costs.

Clark concluded: “I believe [these four principles] will allow us to create a system that relies more than today on a competitive set of market mechanisms to drive down costs, would give to government a strategic role in dealing with externalities as well as dealing with intrinsic uncertainty. It would require an explicit agility in the support for innovation by regulators, and to ensure a structure of charging that does not invite free riding.”

Box 1: Clark’s “new energy vision”

While Clark found Helm’s “reasoning extremely cogent” with regard to a Firm Power Auction to replace the CM and CfD auctions, it would also require unilateral introduction by the UK of a whole economy carbon price that includes the full social cost of emissions. So, in the absence of this, Clark said “I think we need a gradual transition from current mechanisms to a more integrated market” Instead change will be “progressive” with further reforms to the current CfD and CM schemes.

“The concept of greater independence for network operators “is [also] the right long-term approach, and it was important there should be no conflict of interest between the network equipment owner and the network operator. BEIS would legislate where necessary to open up new network requirements to competition.

Clark too wanted a level playing field, in which off-grid or low-grid solutions are rewarded “if they actually contribute to reducing system costs”. He “fully supported” Ofgem’s work to consider the future of network charging,” and this was why the government will also review the way policy costs are recovered. But while he agreed with Helm that the legacy costs of decarbonisation be “cordoned off”, he rejected Helm’s recommendation to exempt industry from all historical policy costs and shift these to general taxation.

But high electricity prices to industrial customers remained a concern. There would be new funding to support industrial energy efficiency and decarbonisation projects and a SME energy efficiency scheme. It was also working with Ofgem to “determine whether new protections are necessary for SMEs and micro-businesses”.

There will be a new review of supply licences, to “ensure we eliminate any unnecessary regulatory barriers”. The regulator will also launch a full review into industry codes and code governance.
There was lots of agreement with Helm, who provided “a compelling vision for the future”. Clark emphasised that he agreed with much of the reasoning, before focussing on three of the key Helm recommendations (those concerning the Firm Power Auction, independent System Operators and dealing with a system dominated by fixed costs). Headlines from the speech are at Box 1.
But it is still unclear what the government intends to do in response to the full suite of recommendations. Instead Clark committed to the publication of a policy paper “in the weeks ahead” and a White Paper “early next year”.

1.5 CCUS

The CCUS (Carbon Capture Usage and Storage) Cost Challenge Taskforce was launched at the start of the year and by mid-year had produced recommendations on a path to cost effective deployment of the technology by the mid-2030s. For a decade or more concerns on costs and effectiveness of the technology have stalled its development, but the lack of alternatives to burning fossil fuels for controllable power and industrial heat means that it has just about clung on to the policy agenda.

Its July recommendations stated a belief that CCUS can be deployed at a competitive cost, as current project concepts are cost comparable with other first-of-a-kind low carbon technologies. It emphasised regional clustering to share knowledge and infrastructure and secure economies of scale as well as the opportunity to develop a new strategic UK industry. To get there a “stable, long term, supportive policy environment” should be put in place to develop at least two clusters from the mid-2020s, supported by an independent business model for transportation and storage of the CO2.

1.6 Record low CM prices

In terms of policy delivery, the first big event of 2018 was the first T-1 capacity auction in January, which cleared at £6/kW for 2018-19 delivery, the lowest ever price realised in a GB capacity auction. Over two-thirds of capacity acquired was from gas turbines.

This was followed in February by the fourth T-4 auction, which cleared at a price of £8.40/kW, which was much lower than all previous T-4 auctions. Those winning agreements included three operational interconnectors and three new build interconnectors planned to be operational for delivery in 2021-22.

1.7 EMR five-year review progresses

The Electricity Market Reform (EMR) package more generally was also up for review in 2018, five years after it laid the foundations for the CM and CfD schemes.
In August, we set out proposals for Reforming the CFD Scheme. This set out the case for a CFD floor price.

Our “claw and floor” model, would see developers bid for a fixed floor price payment necessary to make the project investable. This would guarantee investors a stable return even if wholesale prices fell, because any dip below the floor price would then be paid, via levies, by suppliers back to generators.

Also, under the proposed approach, as wholesale prices climb back up again, generators would not be able to receive the positive difference until the payments they received when the price was lower is reimbursed, or “clawed back”. This would fit in with the government’s envisaged subsidy-free future, while still offering stability to potential investors.

BEIS issued a call for evidence in August on the CM and the Emissions Performance Standard (EPS), but with the focus very much on the former. It said in the document that the underlying reasons for the existence of the CM persisted: significant plant closures due in the 2020s; imbalance prices still yet to reflect the value of system scarcity; the need to underpin investment in capacity; and the existence of barriers to entry. Desirable changes were sought, though it did not “foresee the need for fundamental change” – what was needed was evolution rather than revolution.

What BEIS deemed to be a “priority issue” for consideration was the participation of renewables in the CM – it sought thoughts on whether unsubsidised renewables should be allowed to participate. Another priority was the issue of interconnectors. BEIS sees more investment in interconnectors as a boon to help secure supply, but flagged concerns with the approach to de-rating the assets for the auctions. BEIS said it would consider amending the de-rating methodology for interconnectors to “explore ways to enable cross-border participation in future CM auctions”.

As for the EPS, BEIS’s initial view was that it was achieving its objective, but it welcomed views on whether there are any changes it should consider. The deadline for responses was 1 October, with an intention for BEIS to consult quickly on the priority issues to introduce necessary amendments to the CM rules ahead of the planned auctions in January 2019. But unforeseen developments rather overtook events.
1.8 CM suspension

In surprising – and for many unwelcome – news released on 15 November, the CM was deemed to be in breach of State Aid rules by the General Court of the European Court of Justice. Immediately suspended by the government, National Grid announced that it will continue to operate the scheme, in spite of payments to generators being suspended. Details of the standstill are shown at Box 2. It was brought to court back in 2014 by flexibility specialist Tempus Energy, which considered that the CM favoured traditional generators over DSR flexibility and that this was incompatible with the wider European internal energy market.

The ruling itself stressed that the design of the CM was not unlawful, but the way in which the EC approved State Aid clearance was. It concluded that the EC did not carry out sufficient research into the impacts of the CM on the internal energy market. However, this ruling still stripped the CM of its State Aid approval, rendering the CM inoperable.

The government issued a consultation on 19 December on its proposals for technical amendments to the CM:

- the replacement T-1 auction will be held in summer 2019 but the agreements awarded will depend on the State Aid approval decision
- BEIS is intending to provide deferred payments for capacity providers
- BEIS is assessing options to collect the supplier charge during the standstill period to avoid price spikes when the scheme comes back into effect, and
- current agreements are still enforceable but will not be billed to capacity providers until after the end of the standstill period.

Box 2: CM ‘Standstill’

- CM agreement holders will receive no payments until State Aid is granted
- Secretary of State has confirmed the upcoming T-1 and T-4 auctions are postponed
- BEIS will seek separate State Aid approval for a “replacement” T-1 Auction (subject to new State Aid approval) and to run the postponed T-4 as a T-3 Auction
- Replacement T-1 auction will be held in summer 2019, but the agreements awarded will be dependent on the State Aid approval decision
- CM agreement holders may also request the return of credit cover arising from previous auctions
- Qualification for the postponed auctions will be completed
- CM Supplier Charge (CMSC), the levy of suppliers to fund the CM, is suspended
- Any CMSC contributions already made by suppliers towards the 2018-19 delivery year that the Electricity Settlement Company (ESC) is holding and not paid out will be returned, and all supplier credit cover will be returned in December too, and
- Suppliers remain liable for the Settlement Costs Levy, which funds the ESC operations.

Source: Electricity Settlement Company, EMR Delivery Body
The European Commission should, BEIS noted, formally commence the process for the CM to gain State Aid clearance in early 2019.

1.9 £60mn for third CfD auction

In advance of the Clean Growth Strategy in October 2017, BEIS had already announced up to £557mn of additional support for “less established” renewable electricity projects through CfD auctions. The next round was slated for spring 2019, subsequently confirmed as May 2019.

We had to wait most of the year to learn more, but on 20 November BEIS published its draft budget notice for the third allocation round of the CfD scheme (or AR3), It set an annual overall budget of £60mn in 2011-12 prices. AR3, planned to open in May 2019 for delivery years 2023-24 and 2024-25, is open to Pot 2 “less established” technologies only. This category now includes for the first-time remote island wind (greater than 5MW).

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<tr>
<th>Insight Paper 3</th>
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<tr>
<td>Following the £60mn announcement, we published our insight paper, <em>Turn up the Volume: Reinventing CfD Auctions</em>.</td>
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<td>We argued that CfDs needed to move away from a budget-based auction system to one with procurement based on TWh volume targets or “decarbonisation standard” with annual auctions for a delivery year taking place ahead of CM auctions. We argued that, even though the UK has specific targets to meet in terms of carbon reduction, the current system does not provide a long-term guarantee of exactly how much capacity will be produced in the future. This leaves us with uncertainty over progress towards our targets.</td>
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<td>A volume-based system would give investors clarity over the direction of long-term procurement targets, which will grow or reduce depending on the progress towards decarbonisation.</td>
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Alongside the budget of £60mn, which dictates that total spend in each delivery year cannot exceed this level, BEIS also set an overall capacity cap of 6GW. In addition, no minima or maxima will be applied to specific technologies, meaning that all eligible technologies will compete in a single pay-as-clear auction.

The administrative strike price for offshore wind projects – the maximum price the government is willing to offer to developers – has been set at £56/MWh and £53/MWh for delivery years 2023-24 and 2024-25, respectively. Both of these prices are lower than the clearing price of £57.5/MWh from the second Allocation Round.
1.10 ECO3

ECO is the government’s flagship energy efficiency scheme for domestic energy consumers, administered through suppliers. It has been progressively refined since its implementation in 2012. Phase 2 had been extended as part of the government’s rethink about green levies in 2015, and a transitional phase extended from April 2018 to end September 2018.

BEIS consulted on a long-overdue overhaul to the scheme in 2018, setting out the framework that will apply from October 2018 to March 2022, publishing first its consultation late March, its conclusions in July, and its final impact assessment in October.

In December, ECO3 was finally implemented with the targets – extended from those in place under the previous stage of the scheme – being deemed to be in place from 1 October. The main feature is a shift to a 100% Affordable Warmth scheme for fuel poor, low income and vulnerable households, and other key features of the revised scheme are shown at Box 3. Despite the delay in implementation, measures installed by mandated suppliers between 1 October and 3 December will still be eligible for ECO3.

Overall, we welcomed the scope and approach of ECO3, applauding the clarity over the compliance threshold and the innovation share being embedded.

1.11 Heat

In the heat sector, emissions reduction has been equally lacking, another criticism voiced by the CCC, and in 2018 only limited foundations have been laid for further progress. ECO3 will proceed, representing a continuation of incentives to drive affordable heat efficiency at a domestic level. But it is an extension to existing policy rather than anything transformational. It is also targeted on vulnerable customers, which whilst noble, doesn’t relieve the need to consider how space heat efficiency can be delivered across existing domestic and non-domestic properties.
The main policy focus was BEIS’s *A Future Framework for Heat in Buildings: Call for Evidence* issued in March. The intended outcome signalled in the government’s response published on 7 December is that “We will develop a comprehensive policy framework to support the transition, building on the progress made by the Renewable Heat Incentive. We will continue to support market growth, backed by standards”, with a commitment to in 2019 on regulations, skills and training.

The government ran a competition for pilots under the umbrella of its £320mn Heat Networks Investment project (HNIP). It wants all HNIP funding to be allocated by 2021 with the hope that it will help to leverage £2bn of private sector capital. But this is limited outlay compared to scale of the money needed to meet 2050 targets.

### 1.12 Demise of FiTs

In 2018, the government proceeded further along its path of cutting subsidy for renewables. Following close out of the Renewables Obligation in 2017, in July, we saw the government’s consultation, which provided more detail on the closure of the FiT export tariff from April 2019. This sparked a backlash from solar installers and other affected groups. With the guarantee to sell excess power back to a supplier being stripped away, small-scale generators will have to rely on finding their own route to market, which is unlikely given the current state of the PPA market for very small micro-generators.

The FiT appeared to receive a lifeline in November, when Claire Perry signalled that the government may be rethinking its position, saying in a Commons debate "I do completely agree that solar power should not be provided to the grid for free and that is why I will shortly be announcing the next steps for small-scale renewables.”

However, on 18 December, BEIS published its response to its FiT consultation, confirming that it would be closing the scheme in full, including the export tariff, to new applicants from 31 March 2019. The government said that the decision “reflects our desire to move towards fairer, cost-reflective pricing and the continued drive to minimise support costs on consumers as set out in the Control for Low Carbon Levies.” It concluded that the FiT scheme does not “support the vision set out in the Industrial Strategy and Clean Growth Strategy.”

Unlike close out of the RO, which has been succeeded by continuation of CfD auctions for generation above 5MW and the availability of the offtaker of last resort arrangements, there is no support or route to market for schemes below 5MW. So we produced analysis in September on the need for a Transitional Offtake Tariff to be offered by larger suppliers (see Insight Papers 4 and 5 box) for exports from generation schemes below 250MW and for community schemes below 500kW. This was followed by a further paper in December, calling for a continuation of "volume deeming" for the purposes of guaranteed terms for export for smaller schemes (in effect those below 30kW). We also set out in the second paper a range of options for addressing high levels of spill on the power system and for suppliers to register these volumes in BSC settlement.
Insight Papers 4 and 5

In our Unfit for Purpose insight paper, we set out evidence supporting continuation of a guaranteed route to market for small micro-generation sites after 31 March 2019. It also proposed an optional time of export tariff.

We argued that there should be a “safety net”, comprising:

- the retention of an obligation on larger suppliers to offer terms for export energy
- a transitional period for new low-carbon generators under defined thresholds, and
- an administered price, but one based on cost-reflective energy imbalance prices.

In our Rationalising Micro-generation Exports paper, we recommended a four part solution to complement a Transitional Offtake Tariff. This comprised:

- continuation of a volume deeming rule for sites less than 30kW
- an early statement from government committing to the guaranteed route to market supported by volume deeming
- options for reflected these exports from new sites in BSC settlements, and
- extending these settlement options and arrangements to existing sites currently treated as spill onto the power system.

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Energy:2030

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Cornwall Insight
Creating Clarity
Retail Energy Markets: Stresses and strains aplenty

Key retail market issues in 2018

- High number of supplier exits
- Ofgem triggers mutualisation of RO for the first time
- Ofgem commits to higher supplier vetting and to review the supplier hub
- Some consolidation but SSE-npower merger is dead and buried
- Extension of price caps to safeguard tariff and then government enabled default tariff introduced
- Smart meter roll-out continues to be behind schedule and interoperability issues increase, but BEIS sticks to timetable
- Supplier innovations around packaged EV and battery offerings multiply

2018 has been one of the most tumultuous years seen in the energy supply market since full liberalisation in the late 1990s. For the first time in a decade we have witnessed multiple suppliers falling out of the markets, and Ofgem triggering mutualisation processes to recover unpaid renewables policy commitments for the first time ever. The default price cap – signalled for so long – by year end became a reality, although the methodology for setting it is already subject to a legal challenge.

2.1 Supplier exits

The year saw supplier failures at unprecedented levels with 13 exits during the year amid calls for Ofgem to increase transparency around the Supplier of Last Resort (SoLR) process.

Beginning in February with Future Energy entering the SoLR process, July then saw SoLR invoked twice within a week as Iresa and National Gas and Power both ceased trading. The two most significant failures in terms of affected customers occurred in November as Extra Energy, with 108,000 domestic and 21,000 non-domestic customers, and Spark, with 290,000 domestic customers, were both placed in the SoLR process by Ofgem. In terms of those taking on the customers, it has mostly been medium-sized suppliers, such as OVO Energy and Octopus, consolidating their position. All the exits are summarised at Figure 1.

This multitude of failures arose as fierce competition and rising costs proved too much for some. All suppliers faced challenging conditions as the Beast from the East early in the year caught many by surprise and heaped large unforeseen costs on all. Throughout the year wholesale prices steadily increased, electricity imbalance prices became more volatile, and confirmation of the default tariff price cap made the need to hedge wholesale costs more important for those with the resources to do so.

Towards the end of the year, it became apparent that there were outstanding and large cash calls required under the buy-out rules of the Renewables Obligation (RO).
### Figure 1: Supplier exits in 2018

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Exited</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Future Energy</td>
<td>February 2018</td>
<td>Customers taken on by Green Star Energy under Ofgem’s SoLR mechanism</td>
</tr>
<tr>
<td>Flow Energy</td>
<td>May 2018</td>
<td>Acquired by Co-operative Energy</td>
</tr>
<tr>
<td>Iresa</td>
<td>July 2018</td>
<td>Customers taken on by Octopus Energy under Ofgem’s SoLR mechanism</td>
</tr>
<tr>
<td>GEN4U</td>
<td>July 2018</td>
<td>Customers taken on by Octopus Energy under Ofgem’s SoLR mechanism</td>
</tr>
<tr>
<td>National Gas and Power</td>
<td>July 2018</td>
<td>Non-domestic market. Ofgem appointed Hudson Energy as SoLR for its 80 business customers</td>
</tr>
<tr>
<td>Affect Energy</td>
<td>September 2018</td>
<td>Acquired by Octopus Energy</td>
</tr>
<tr>
<td>Snowdrop Energy</td>
<td>October 2018</td>
<td>Snowdrop Energy is transferring all its customers (approx. 6,000) to Nabuh Energy due to the pressure of rising wholesale prices</td>
</tr>
<tr>
<td>USIO Energy</td>
<td>October 2018</td>
<td>Ofgem appointed First Utility to be the Supplier of Last Resort for USIO Energy’s 7,000 customers</td>
</tr>
<tr>
<td>Planet9</td>
<td>October 2018</td>
<td>Non-domestic venture of the ESB in GB. Stated in financial accounts that operations would cease by October 2018</td>
</tr>
<tr>
<td>Extra Energy</td>
<td>November 2018</td>
<td>Ofgem appointed Scottish Power as SoLR for the company’s 108,000 domestic customers and 21,000 business customers</td>
</tr>
<tr>
<td>Spark</td>
<td>November 2018</td>
<td>Ofgem appointed Ovo Energy as SoLR for the company’s 290,000 domestic customers</td>
</tr>
<tr>
<td>OneSelect</td>
<td>December 2018</td>
<td>Ofgem appointed Together Energy as SoLR for OneSelect’s 36,000 customers</td>
</tr>
<tr>
<td>EPhase</td>
<td>December 2018</td>
<td>Entered administration in August after the directors had started winding up the company</td>
</tr>
</tbody>
</table>

*Source: Cornwall Insight*
2.2 **RO and FiT mutualisation**

This final element proved very significant as in November Ofgem confirmed that it would trigger a mutualisation process for the first time ever following a £58.6mn shortfall into the 2017-18 RO late payment fund (see Figure 2). The shortfall came as a result of supplier exits and from other suppliers who simply couldn’t make their payments on time.

The regulator also announced that a shortfall of payments into the levelisation fund for the Feed-in Tariff (FiT) scheme had similarly triggered a mutualisation process. The £4.07mn threshold was reached for the Q3 2018 FiT levelisation period with a shortfall of £4.17mn established.

**Figure 2: Suppliers with late RO payments (as at October)**

![Bar chart showing the number of suppliers with late RO payments from 2015-16 to 2017-18](chart.png)

*Source: Cornwall Insight*

RO mutualisation for 2017-18 will cost remaining suppliers about an extra £0.20/MWh. We expect it will cost them another £0.10/MWh for 2018-19 even without any new supplier failures, as the exits we have seen already this year create a shortfall in excess of £20mn against the mutualisation threshold of £16.9mn. So, suppliers will be making RO mutualisation payments for at least two years from September 2019.

2.3 **Regulatory response**

The shortfalls reflect the perverse incentive for suppliers to use cash collected under tariffs today from their customers (and that they are obligated to collect on behalf of others) as working capital to meet commitments tomorrow. Ofgem and the government have belatedly begun looking at much-needed rule changes in response.
to incentives like these and also the way suppliers serve their customers, given the way that service problems marked the likes of Extra and Iresa as they failed.

In the aftermath of the exits, questions are being asked about the incentives created by SoLR for shareholders of companies that failed but also those that gain their customers. Some say that the guaranteeing of credit balances through SoLR—and ultimately underwritten through all customers—means incentives to price rationally are reduced as there will be no liability for credit balances for shareholders on exit.

Equally it seems that incentives for companies to acquire distressed-but-not-yet-failed suppliers are reduced as SoLR allows buyers to take on the customers without the liabilities. The full costs of the SoLR levy payments have only been proposed to date for Octopus’s July 2018 takeover of Iresa at £13.8mn, equivalent to about £70 per account or 50p across all British households. Should these costs be consistent for the other SoLR exited suppliers, a total bill of the order of £70mn can be expected in the end to be levied for SoLRs. In combination with the RO and FiT mutualisations, the supplier exits of 2018 will cost suppliers (and in the end consumers) of the order of £150mn (about 0.4% of total consumer spend on electricity).

More generally, the regulator initiated a consultation in December seeking views on important changes to market entry and its monitoring processes. We have also seen a decision confirmed in November to modify SoLR supply licence conditions from next year, and a wider BEIS/Ofgem review of the existing system of energy code arrangements aiming to ensure that regulation is “agile and responsive”.

BEIS has also asked Ofgem to kick off a review of the supply licence, the first for over a decade.

Changes to the supplier hub are also being investigated by Ofgem, which sign-posted industry responses at the end of July to its consultation from November 2017. The hub structure template remains deeply centralised and has not changed since 2001, while the electricity system has progressively decentralised, coupled with the hub becoming embedded in the wider legal and regulatory landscape with the introduction of policy support schemes implemented through suppliers.

We commented on a number of occasions that the political focus on price caps over a prolonged period of time may have distracted Ofgem’s attention from these actions to tackle changing risks in the supply market and has arguably made the recent failures more difficult to manage and head off.
2.4 Continuing supply market development

Even with the exits, the share of domestic customers outside the Big Six has surged through 25% as 2018 has seen historically high levels of market engagement.

Energy UK’s latest figures highlight 5.4mn domestic electricity switches by the end of November – a 6% increase compared to the same point in 2017.

Meanwhile, new entry continues but its model has shifted to white label from direct and new participants have not been enough to stop the market from seeing its first net annual reduction in domestic energy suppliers since 2006. Then we were left with just eight suppliers. At the end of 2018 and despite 11 exits, we still posted over eight times that number at 89 including white labels. There were even more business suppliers at 96. Changes in the total number of suppliers is shown at Figure 3.

Figure 3: Number of energy suppliers 2016 to 2018

Source: Cornwall Insight
The beneficial impact on competition is reflected in further reductions in market concentration levels across all parts of energy supply, measured by the Herfindahl Hershman index (HHI). The lower the index, the more competitive the market is assessed as being, with 1,500 representing an important threshold below which a market is deemed to be competitive. Figure 4 shows recent trends, including the least competitive sector, the domestic gas market, falling below this level at the start of 2018. All sectors have become increasingly competitive over the course of the year.

Figure 4: Trends in HHI

Source: Cornwall Insight
2.5 Consolidation

Since 2016 the number of forced or planned supplier acquisitions within the retail market has accelerated. As we anticipated, that trend has continued, and this year saw deals including First Utility with 1.6mn accounts being acquired by Shell for £240mn and Flow Energy with 0.2mn accounts acquired by Co-operative Energy for £9.25mn.

The year also saw the development of one of the largest ever proposed supplier mergers between the domestic business of SSE and the full retail energy business of npower. Initially put forward in November 2017, significant progress was made in 2018 on the deal, and in August the merger was cleared by the Competition and Markets Authority (CMA). The two firms initially expected the merger to be completed in Q4 2018 or Q1 2019.

A Phase 1 investigation decision by the Competition and Markets Authority (CMA) published in May resulted in the proposal being put to an in-depth Phase 2 investigation as a result of concerns raised that it could have a negative impact on competition in the market. The CMA then announced in August that it had provisionally cleared the merger, with a final report in October concluding: “the proposed merger may not be expected to result in a substantial lessening of competition.”

We commented that the idea was a bold move that could have signalled the end of the traditional supplier model, and one that had the potential to create a significant new retail energy competitor. If the deal had gone through, it would have created the second largest domestic energy supplier in GB after British Gas.

However, Ofgem finalising the default tariff cap in November contributed to the two firms re-opening their negotiations and we highlighted that the unusually late timing of the renegotiation demonstrated how much and how fast the retail supply market is changing. On 17 December it was announced that the deal would not go ahead after SSE said it was no longer in the best interests of its stakeholders to proceed.

The decision not to pursue the merger was one sign of the tough times being experienced by suppliers of all sizes. Both SSE and Centrica issued profit warnings in the second half of the year as they struggled with rising wholesale prices and increased retail competition.

Consolidation was also a theme of the non-domestic intermediary market in 2018, which attracted far fewer headlines than its domestic counterpart but in late December the acquisition of Inprova by Inspired Energy brought together two top tier rivals in to the first mega TPI, with the balance sheet and heft to match many suppliers in the market.
2.6 Price caps

After being passed by Parliament, the *Domestic Gas and Electricity (Tariff Cap) Act 2018* became law in July, allowing Ofgem to put a default tariff price cap in place. The design was finalised in November and came into force on 1 January 2019. The regulator set the final level of the cap at £1,137/year for a “typical” medium user. The cap aims to protect 11mn households on “poor value” default deals, with an expected annual saving of around £76 on average.

We highlighted in September that, while the largest suppliers will be impacted by the cap (Figure 5), the average medium supplier SVT was £55 below the cap with the smallest suppliers at £148 below. There were also concerns raised over whether the cap could bring unintended consequences by discouraging switching – which Ofgem noted is likely to fall by around 30% as prices converge – and see suppliers increasing their fixed tariffs to compensate. Labour said it was “a smaller saving for fewer people” than originally intended and criticised long delays in implementation.

With wholesale costs continuing to rise, prices under fixed deals will continue to increase. This could have the perverse effect of engaged consumers switching from fixed deals to SVTs, or of pushing customers to very small suppliers who will then grow through the policy thresholds much quicker.

*Figure 5: Large supplier default tariffs at 30 September 2018*

*Source: Cornwall Insight*

We therefore pointed out that those expecting the cap to halt increasing household energy bills will be disappointed. Wholesale costs would need to fall sharply to drive change, and we expect a further rise in the default tariff cap at the March 2019 reset.
Elsewhere, the domestic prepayment meter (PPM) cap introduced in February 2017 was extended by Ofgem in February 2018 to cover a further 1mn customers in receipt of the government’s Warm Home Discount and renamed the Safeguard Tariff. It was announced that those who receive the Warm Home Discount and were on an SVT or default tariff would be price protected at the level of the PPM cap until the end of 2018, after which they would transfer to the default tariff price cap.

Again, competition concerns were raised during the year and a report by former electricity regulator Professor Stephen Littlechild in October found that the range of PPM offers available and significantly below the cap was much smaller than suggested by Ofgem data. It found that, with the exception of one fixed tariff from a large supplier, all large and medium suppliers were pricing at the level of the cap, along with several small suppliers.

But it was not just competition concerns that were vexing the industry. Right at the end of the year Centrica announced a judicial review challenge of the way the default cap treated wholesale costs to “correct” Ofgem’s “failure to enable the recovery of the wholesale energy costs that all suppliers incur”.

While the company does not “believe that a price cap will benefit customers” it has “no intention to delay implementation”. Rather it wants to “ensure that there is a transparent and rigorous regulatory process to deliver a price cap that allows suppliers, as a minimum, to continue to operate to meet the requirements of all customers”.

### 2.7 Smart meters

Progress towards the smart meter roll-out deadline continued in 2018 with around 5mn domestic meters expected to be installed during the year, helping to bring the expected overall total of operational meters in GB homes and businesses above 13mn. However as of June, the NAO said that 39mn meters were yet to be replaced with smart meters and with just two years left for suppliers to take “all reasonable steps” to ensure all homes and eligible small businesses have a smart meter offered by the end of 2020, the programme is struggling.

The NAO then warned in November that the roll-out will “fall materially short” of the 2020 target (see Figure 6) and expects that the it will only be at best around 70%-75% complete. On top of this, the government’s latest smart meter installation statistics revealed that domestic smart meter installations by the 14 large energy suppliers in Q3 2018 had fallen by 10% compared with Q2 2018, from 1.2mn to 1.1mn as SMETS1 stocks are run down and not enough SMETS2 meters are being installed to fill the gap.
There have also been ongoing issues with interoperability with first generation meters with around 1mn SMETS1 meters now operating without smart functionality following a change of supplier. However, in its latest update in November the Data Communications Company (DCC) confirmed that, through a “proof of interoperability” demonstration, it had established that its systems can connect with a SMETS1 meter and that users will see their smart capabilities restored once the meters are enrolled into the national smart meter communications network.

BEIS confirmed in October that suppliers will be required to take all reasonable steps to enrol SMETS1 meters with the DCC within 12 months of the point at which they can be enrolled – expected to begin in May 2019. However, it is clear that SMETS2 meters should remain the priority going forward. On 5 December an end date for SMETS1 meters counting towards suppliers’ roll-out targets was finally enacted after being extended several times, although a derogation for 12 suppliers has effectively extended the end date once again to 15 March 2019.

Given these stark delays, we agree with the NAO that the deadline will be missed and with stakeholders, such as Citizens Advice, calling for the target to be pushed back to reflect the myriad of delays to the programme. We believe efforts should be focussed on ensuring that the end-to-end infrastructure is fit for purpose for all smart meters rather than fixating on an asset roll-out deadline, which is only part of the overall programme. However, for the present at least, the government has rejected calls to delay and is sticking to its target.
2.8 Other innovations

Elsewhere, green shoots of innovation have emerged among suppliers throughout the year with various new offerings. These have included suppliers launching tariffs that give customers access to time-differentiated energy prices with app alerts when prices are low, as well as a new variable tariff that directly tracks wholesale energy costs, rather than charging customers an independent standard variable rate.

The EV space continues to evolve rapidly, along with developments in home battery technologies. Several energy players have made moves into these new markets, including EDF, E.ON, ScottishPower, Green Energy, OVO and Octopus Energy to name a few. “Fully-integrated” packages are emerging that offer consumers low-carbon electricity, EV charging solutions and battery optimisation services.

In the non-domestic space, there have been moves to optimise energy flexibility for businesses. Flexitricity and SSE both launched energy supply programmes to bring together different types of distributed energy resources to enable users to cut costs and earn additional revenue through providing balancing services.
Networks: Regulation fit for the future?

Key network regulatory issues in 2018

- Early conclusions are emerging from Ofgem’s Significant Code Review (SCR) of residual charges
- Balancing charging likely to see significant change but this will be subject to further work
- Another SCR launched on access and forward looking charges: outcome is likely to be greater alignment between transmission and distribution charging
- RIIO-2 framework emerging, with important differences from RIIO-1
- System Needs and Products review progresses with new pilot auctions scoped and wider access promised
- Gas transmission charges also under review, but process stalls

The overall theme of 2018 has been a regulator-led review of the fundamentals of network regulation, both what the networks are required to deliver in today’s market environment and how much this should cost consumers, and how the costs of networks should be charged and fairly shared to provide signals and to recover outlays.

While this has the potential to provide better economic signals and better value to consumers, it also portends change that has the potential to be disruptive, as the arrangements that have incrementally built up over years are swept away. The interactions between the various parts that Ofgem has started moving are complex, with changes to signals that have built up over many years from applying marginal cost related pricing models.

Even a small shift in pricing models is potentially a seismic change with impacts across the market, particularly when the changes are combined with possible measures to remove remaining embedded benefits.

3.1 Future of network charging

In 2018 there have been key developments in relation to forward-looking network charges, which are intended to provide cost signals to users about their impacts on the networks, as well as the residual charges that are intended to recover all the remaining costs allowed by the regulator for managing and financing the networks. Currently network tariffs applied to users do not reflect this distinction in charges, being blended rates set on a variety of connection, volume and locational factors.

3.1.1 Residual charges

Ofgem has made earlier progress on the residual part. In November it delivered its delayed Targeted Charging Review Significant Code Review (SCR) proposals on residual network charges. The regulator’s stance throughout this workstream, which kicked off in July 2017, has been that the payment of residuals should not incentivise particular behaviours but rather that they should be applied equitably across users of the network.
Its approach is to move towards fixed charges, either on the basis of a fixed charge which is the same for each segment of customers (its preferred option), or on the basis of agreed capacity, which would be deemed for domestic customers.

The regulator argued that there is a strong theoretical basis for fixed charges, as they cannot be easily avoided other than by exiting entirely from the networks. The benefits of this approach will be largely found in through the removal of distribution charging and triad avoidance (see Figure 7).

However, both lead options would bring about a significant re-distribution of charges, with some types of consumer affected more than others. Key losers will be large transmission-connected users that currently employ triad management to reduce their exposure to the charges, as this will no longer be an effective technique to avoid residual charges. The proposal has implications for the future viability of on-site generation that is used solely or mainly for triad avoidance, rather than responding to wholesale prices or forward-looking charges. It also has implications for affordability as many of the users who stand to lose out are the intensive energy users who have gained from abatements in renewables policy costs.

**Figure 7: Consumer costs, difference between Baseline vs Steady Progression (Full reform)**
3.1.2 Embedded benefits

The scope of the SCR also included consideration of the remaining non-locational embedded benefits not addressed by its decision on CUSC modification proposals CMP264/265 in 2017, which removed the triad embedded benefit. This was an issue that persisted in 2018, with the case being discussed in the High Court in June. In this instance, the court deferred to Ofgem, a decision that served as a reminder of the limits of Judicial Review as a mechanism for challenging decisions by economic regulators.

The outcome of this decision resulted in triad benefits reducing by approximately one third in 2018-19 (depending on location) and will see the value reduced further in 2019-20 and 2020-21.

The SCR also considered the remaining non-locational embedded benefits. Ofgem has now proposed to charge Balancing Services Use of System (BSUoS), which represents the day-to-day costs of managing the system and is forecast to amount to around £1.2bn in 2018-19, on a gross basis. This would remove the associated benefit currently enjoyed by embedded generation. Further Ofgem has also proposed that embedded generators should contribute to the costs of managing the system by paying BSUoS charges as well for the first time. This is proposed to be implemented in either April 2020 or April 2021.

At the transmission level, Ofgem has proposed to seek to set the transmission network use of system (TNUoS) generator residual charge to zero. This charge is currently negative, so would no longer be received by generators, although implementation will depend on keeping within the EU Regulation that limits annual average generator charges.

The proposed changes, though seemingly logical, make the investment case for some embedded generators more challenging and invites searching questions about exactly where their value lies, even as we move forward into a more smart and flexible system. In the meantime, there are likely to be negative impacts on investor confidence from the scale of the changes, however clearly their general direction was signalled.

The consultation on these proposals closes in early February and a final decision is expected mid-2019.

3.1.3 Forward looking charges

As 2018 came down to the wire, Ofgem issued its proposals for taking forward its project on network access and forward-looking charges. It has confirmed its intention to launch yet another SCR. This will take forward:
• a review of the definition and choice of access rights for transmission and distribution users
• a wide-ranging review of distribution use of system charges
• a review of the distribution connection boundary, and
• a focused review of transmission network charges, which will concentrate on the charging of distributed generation and demand users.

This has the potential to see a much closer alignment between the arrangements at transmission and distribution level and, together with the changes to residual charges, could fundamentally shift the preference of much new generation seeking to connect at distribution level. This would also align with the regulator’s goal to see a whole system approach to network development, on which it issued a consultation on licence changes at the same time.

In addition, the Electricity System Operator (ESO) and network companies are being asked to separately take forward:

• a review of aspects of allocation of access rights, including improved queue managements and scope for trading, and
• a review of balancing services charges by the ESO through a task force.

Ofgem expects to consult on its minded to decision in spring 2020 with a final decision in the autumn before implementation ahead of the 2022 and 2023 charging years.

More focused and appropriate cost signals should lead to a more efficiently sized and shaped network, but again the process of getting there will lead to winners and losers in the shorter term, in addition to the experience of disrupted expectations. Managing the process to provide early transparency and solid justifications for market participants will be important to minimising adverse consequences.

3.2 RIIO-2

The ongoing process of setting the next set of price controls for the networks continued throughout 2018. This work took place in the context of continued scrutiny of the RIIO-1 price controls, with criticism aimed at the perceived level of risk facing companies and the revenue granted for infrastructure that ultimately is not built, such as the now-cancelled Moorside power station.

The original move from RPI-X to RIIO was largely about shifting from a cost restraining approach to ensuring that networks – in particular electricity – had the investment necessary to integrate the vast growth of renewables.

In 2018, the focus was on developing the framework for RIIO-2, with a consultation published in March and the framework decision being delivered in July. The former
outlined several proposals from Ofgem, including the setting of a default five-year control period (in contrast to the eight-year period under RIIO-1), a focus on the delivery of “whole system outcomes”, the separation of the electricity system operator price control from electricity transmission, and a simplification of price controls. Ofgem also confirmed that it did not intend to align the electricity distribution price control, due to start in April 2023, with the gas and electricity transmission, gas distribution, and ESO price controls that will start in April 2021. The timetable is shown at Figure 8.

Giving consumers a stronger voice is a key theme of Ofgem’s updated approach to price controls. It referenced a planned enhanced engagement model, including the establishment of consumer engagement and user groups at company level, and a central RIIO-2 challenge group. There are also to be public hearings on company business plans.

**Figure 8: Indicative high-level milestones**

<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>March 2018</td>
<td>RIIO-2 framework consultation</td>
</tr>
<tr>
<td>April 2018</td>
<td>RIIO-2 enhanced engagement guidance</td>
</tr>
<tr>
<td>July 2018</td>
<td>RIIO-2 framework decision</td>
</tr>
<tr>
<td>December 2018</td>
<td>Sector specific methodology consultation</td>
</tr>
<tr>
<td>May 2019</td>
<td>Sector specific methodology decision</td>
</tr>
<tr>
<td>Q4 2019</td>
<td>Companies Business Plan formal submission to Ofgem (along with RIIO-2 CCG and user group reports on Business Plan to Ofgem)</td>
</tr>
<tr>
<td>Q1/2 2020</td>
<td>Open hearings</td>
</tr>
<tr>
<td>Q2 2020</td>
<td>Draft determination</td>
</tr>
<tr>
<td>November 2020</td>
<td>Final determination</td>
</tr>
<tr>
<td>December 2020</td>
<td>Statutory Licence consultation</td>
</tr>
<tr>
<td>February 2021</td>
<td>Licence decision</td>
</tr>
<tr>
<td>1 April 2021</td>
<td>Start of RIIO-2 price control for ET, GT, GD and ESO</td>
</tr>
</tbody>
</table>

*Source: Ofgem*

In respect of key financial issues, Ofgem has ruled out the full debt pass-through options for setting the cost of debt, but it will further assess the other two options of recalibrating the RIIO-1 index or having a fixed allowance for existing debt and index new debt. A hard cap and floor as a potential mechanism to adjust network company returns to ensure they are “fair”, owing to potentially distortive effects, is also proposed. However, the regulator will also continue to explore the applicability of four other options raised, including discretionary adjustments.

In our view, there are still many decisions to be taken. As the second iteration of a complex mechanism with many interlinked parts, RIIO-2 must balance the interests of diverse stakeholders in a rapidly changing environment – a substantial challenge.

However, we found much to commend in the direction that has been set, particularly with regard to innovation playing a growing role in core functions – essential given
the expected transition over the coming decades. The shortening of the price control period will also allow new realities to be factored in more readily.

Work to develop the methodology for applying the framework for the gas distribution networks, the electricity transmission networks, the gas transmission network (including the gas system operator) and for the electricity system operator, is ongoing.

Just before Christmas, Ofgem issued a consultation on the RIIO-2 sector-specific methodologies for all sectors except electricity distribution which is due to start two years later than the rest, in April 2023. The focus on reining in network returns was clear in Ofgem’s proposals to set a baseline cost of equity returns at 4% (under CPIH), about 50% lower than the previous price controls, and to keep adjusting the cost of debt annually. This is expected to save consumers £6.5bn in the next price controls from 2021 onwards.

Formal submission of business plans will take place for electricity distribution, gas transmission, gas distribution and the electricity system operator will take place in Q4 2019, before a final determination is expected in November 2020.

### 3.3 New approaches to balancing services

This year has seen the continued transition to a more decentralised, decarbonised grid. As a result, how the power networks are balanced became an area of increased focus, particularly regarding existing routes to balancing being saturated and the need to open up new routes for new participants.

The primary driver behind opening up new markets is National Grid’s *System Needs and Product Strategy* (SNAPS), which continued to progress during the year. Potential approaches under this strategy include valuing inertia in a future voltage market design, incorporating faster frequency response services into the wider products available rather than running new tenders for these, the rationalisation of reserve products, and potential changes to black start contracts.

It has been widely recognised that, historically, there have been too many balancing products, with criteria for entry and the objectives of the services themselves being overlapping or murky. Our view was that the move to rationalisation has been necessary and is welcome.

Beyond consolidation, the sector has seen the development of a trial of a weekly cleared price auction for a defined volume of our frequency response requirement. This will look at testing several potential improvements and new areas of functionality designed to increase market transparency and lower barriers to entry for new providers.
The trial will consist of four response products: high dynamic, low dynamic, high static, and low static. The auction will be pay-as-clear with the forward volume requirement identified and published before each auction. The trial period for this will now be extended due to its complexity, with the start date pushed back to mid-2019. Design and modelling work on a new suite of frequency response services is also ongoing, addressing several issues with the existing primary, secondary, and high services and enabling faster acting response and unbundling. A reserve services review will also be published in 2019, while Project TERRE – the cross-national exchange of replacement reserve – could be live as early as Q4 2019.

National Grid as the ESO set out a roadmap to widening access to the Balancing Mechanism in July. It explained how it would improve information, simplify balancing services and cut barriers to participating in the Balancing Mechanism (BM) through:

- improving existing routes to market including for aggregators
- developing new routes to market for those wishing to provide near real-time flexibility, and
- enhancing IT systems to improve data flows for market participants.

The ESO also issued a roadmap on widening access to the Balancing Mechanism, setting out how barriers to entry for small and aggregated units could be removed. This set out actions such as improving existing routes to market, developing new ones, and enhancing IT systems so that they are more efficient and cost effective. Its proposed timetable is shown in Figure 9.

Figure 9: Roadmap of actions and milestones relating to BM wider access July 2018 to April 2020

Source: National Grid
### 3.4 Gas transmission charging

It has been a similarly fluid year for the developing reforms to the gas transmission charging arrangements. Originally launched by Ofgem with a call for evidence in 2013 to address certain specific problems identified on the workings of the current arrangements — notably the increasing need for commodity charges to recover allowed revenue in a system with plenty of capacity — the focus has become increasingly on compliance with the gas tariff network code (TAR NC), which is due to be implemented in May 2019.

Ofgem did not (which perhaps it now regrets) launch an SCR and the process of developing changes was initially taken forward under the UNC transmission charging methodology forum.

A key aspect under consideration, although there are also a number of others, has been the efforts to move from a Long Run Marginal Cost methodology to one of the reference price methodologies permitted under the TAR NC, with much development work going into the Capacity Weighted Distance model. An alternative using the postalised model was also been put forward. Issues of contention have included how to address the future of the optional commodity charge, or shorthaul tariff, the appropriate discounts for storage and the treatment of arrangements at Interconnection Points.

The original proposal raised by National Grid in July 2017, UNC621 Amendments to the Gas Charging Regime, eventually saw 10 alternatives raised, most in the first few months of 2018. These were then sent to Ofgem, with none of them recommended by the UNC Panel at its meeting in July 2018. The Panel considered the review should have been undertaken as a Significant Code Review and believed this would have avoided the governance issues. It also identified a series of issues with the analysis and Panel members considered that determination of whether revenue redistribution is fair, reasonable and timely or not is “incredibly difficult” to assess without a pan-industry view.

Ofgem has now rejected UNC621 and all of its alternatives, setting out that none of the proposals would ensure compliance with the TAR NC requirements. In particular it found issue with the proposed replacement for the short-haul tariff, and that there would be distortions from giving special treatment to existing contracts.

The regulator said that it expects industry to take into account its views and develop a compliant modification. However, a lot of work on a short timescale would be needed if compliance by 31 May is to be achieved, and a derogation from the code seems to be the only viable alternative. The process has demonstrated the difficulties of driving forward change in complex areas with multiple dependencies, and the regulator’s difficulties are compounded by the need to comply with the EU timetable.
Wholesale markets: Rising prices and increased volatility

2018 commenced with the sector feeling the impact of several winter gas supply incidents that simultaneously struck the UK, Continental Europe and Norway – this happened during the first winter without the gas storage capacity of Centrica’s Rough facility, compounding the volatility and created concerns over the market’s preparedness for extreme events.

Then the weather turned and winter 2017-18 ended with the “Beast from the East” storm that swept across Europe. It was the first time a system alert had been issued in its current format (a “Gas Deficit Warning”), as information from the system operator triggered a market response for extra gas as temperatures dropped well below seasonal norms.

As the year progressed, other events influenced market activity, including the final stage of changes to how the electricity Single Imbalance Price (SIP) is calculated. Commodity prices cycled through the year, with surges and then slumps in oil and coal prices and the carbon market reaching decade highs.

### 4.1 Volatility across the market

Commodities experienced volatility in prices throughout the year, following the pervading trend. Oil in particular saw volatility both in terms of price and wider market developments. Slow yet sustained growth saw the month-ahead Brent crude price rise above $85.0/bl in October, its highest level in almost four years. Then, in a little over two months, the gains experienced in the first 10 months of the year were swiftly eroded.

In the first half of the year, oil prices were supported by a tightening in global supply, primarily driven by OPEC production cuts that were extended from 2017 into 2018. Compliance with these cuts rose to as high as 140%, with the economic crisis in Venezuela and unplanned disruptions in Libya leading to cuts far greater than the original 1.2mn bl/d agreed.
From October, fresh fears of an oversupplied market, amid higher OPEC production and forecasts of slower oil demand growth in 2019, saw prices plummet during November, erasing all gains made in 2018 and falling below $60.0/bl for the first time since October 2017.

EU ETS carbon prices saw significant growth in 2018. Starting the year hovering around €8.0/t, prices reached €25.0/t towards the end of the year. While this suggests a remarkable, yet consistent rise, there was still volatility in the carbon market, particularly from September onwards. Prices rose above €25.0/t in mid-September, for example, but had shed nearly €10.0/t to sit at €15.6/t by the start of November.

API 2 coal prices started the year at approximately $90.0/t and look set to end the year around the same level. Again, some volatility was experienced, with prices falling to $73.0/t in March and briefly breaching the $100.0/t mark in early October.

4.2 Gas storage, security and supply

The wholesale market in 2018 has been volatile since the events of last winter, largely as a result of several gas supply incidents. The impact of the first of these, the closure of the Forties oil pipeline on 11 December 2017, was initially only felt in the oil market. However, an explosion at Austria’s main gas pipeline hub and the subsequent re-routing of gas flows around Europe created a domino effect. This ended in Norwegian assets flowing gas into the UK and Europe and caused day-ahead gas prices to jump across the continent, with those at the National Balancing Point (NBP) – the virtual trading location for the sale, purchase and exchange of UK natural gas – reaching a four-year high of 78p/th.

![Figure 10: Volatile wholesale prices as a result of the Beast from the East](Source: Cornwall Insight)
At the start of February, a second outage at the Forties pipeline caused a shorter, sharper shock in both the gas and the oil markets. These events highlighted to the market the UK’s tighter gas security of supply position after the closure of Rough.

These developments were particularly pertinent given that by February supplies held in storage sites in Britain, Belgium and France were at their lowest since 2015, LNG shipments to GB had decreased, and, as noted, the market was without the storage capacity of Centrica’s Rough facility for the first winter since privatisation.

The gas market was tested again towards the end of the month with the Beast from the East, which arrived on 24 February. The storm, which resulted in temperatures dropping as much as 10 degrees below seasonal norms, led to gas demand reaching eight-year highs and within day NBP gas prices reaching record levels on 1 March, prompting the Gas Deficit Warning (Figure 10 shows price volatility during the Beast from the East).

While fears of gas market failure and forced disconnections circulated, fuelled by the supply incidents at the very start of the year, the reality was what could have been expected: the market experienced significant volatility with large and sudden price swings. But high flexibility values in response to the Gas Deficit Warning allowed the market to balance. Figure 11 shows the changing composition of gas supply.

The Beast from the East depleted gas storage supplies to record lows, both in GB and across the continent. National Grid said it had a requirement to buy locational gas and invited shippers to post offers in the on-the-day commodity market (OCM) at all locations in a bid to reduce demand. This resulted in within-day NBP prices soaring, reaching a record level of 350p/th in the OCM.
Despite the volatility, the wholesale market worked as it should. The liquid and relative (to electricity prompt markets) easy access to the OCM for shippers and the System Operator demonstrated how tough conditions can be successfully managed without supply interruptions. But we were again reminded that there is a difference between physical energy flows and cashflows for suppliers. With the spike driven by heating demand from customers on fixed tariffs, retailers struggled to manage this price shock even though they were prudently hedged. Some suppliers upped direct debit payments to see them through often to the shock of their customers and the concern of the regulators. For some the Beast from the East meant they were unable to recover expected cash-flows before RO bills became due at the end of October 2018.

However, taken in combination with the events at the very start of the year, it reopened debate around whether it is prudent to pay the insurance premium of developing more gas storage capacity. This debate has yet to reach a final conclusion but, because the market has had to contend with concerns over the nation’s readiness for winter, wholesale gas and power prices have sustained unseasonal highs into the summer.

4.3 Carbon prices

Carbon prices increased consistently month-on-month across the year in a manner not seen for some years. Typically, carbon had averaged around €6-8/t in recent years as the EU has combatted concerns of oversupply with its Market Stability Reserve. However, in 2018 the market peaked at €26/t, equating to 210% growth and was a major driver power, were so high over the year (see Figure 12).

Figure 12: Price of carbon 2008-18 (£/t)

Source: Cornwall Insight
As for many other sectors, uncertainty around Brexit has played a role in the interaction between carbon and market pricing. Large GB generators pay a total carbon price per tonne of CO2 emissions that comprises the sum of the UK-specific Carbon Price Support (CPS) and the traded price for carbon permits under the EU ETS.

Chancellor Philip Hammond confirmed in the Autumn Budget on 29 October that government would again freeze the CPS at its current level of £18/t out to the end of 2020-21. However, he also said that he may seek to reduce it after 2021 if EU ETS prices remain high, though precisely what “high” is remains unclear.

The UK has informally agreed to remain in the EU ETS until the end of phase 3 (2013-20). However, throughout the year inconsistent signals have been given by ministers, with Claire Perry suggesting that in the event of a no deal Brexit the UK would develop its own mirror scheme to the EU ETS. The outcome, to date, is that the market has faced sustained uncertainty on the design of any future carbon tax and on the carbon pricing policy post-2021.

Carbon pricing impacts wholesale prices here and elsewhere through the uplifting impact it has on coal and gas generators’ short-run marginal costs. In turn this relationship between carbon prices and wholesale prices means there is a close interaction with low-carbon support mechanisms such as CfDs in the sector. The lack of certainty after 2021 could have unintended consequences for existing market auctions and incentives, as well as the wider energy system.

Any reduction in carbon price after April 2021, for example, could increase the cost of projects supported under CfDs due to misalignment with the reference power price curves used in auctions. Continued uncertainty also makes it more difficult to assess the generation merit order over the coming years as low carbon prices could see an increase in coal generation, and lead to a fall in electricity prices, both of which could potentially cause a reduction in the level of imports through interconnectors and the revenues earned from their use.

Uncertainty around carbon pricing has posed some hard questions for market participants this year. But the real issue is what the government will do with its view on the target carbon price.

4.4 Fully marginal electricity imbalance prices

November saw the final step in the implementation of Ofgem’s Electricity Balancing Significant Code Review (EBSCR), which altered the electricity imbalance price calculation rules via the “P305” rule change to the BSC. The now fully implemented change creates sharper and more volatile prices in order to encourage more efficient trading and increase the default costs for disconnections and reserves.
Under the changes the Price Average Reference (PAR) volume was reduced to 1MWh (PAR1) from the interim 50MWh (PAR50) that was introduced on 5 November 2015. Our analysis shows that, during the first half of the year, under a PAR1 scenario prices in the wholesale market would have been more volatile in a short market. For market participants, the move to PAR1 likely meant more occurrences of significant cash-out price spikes – under the Beast from the East, for example, imbalance prices would have averaged £15.10/MWh higher in short settlement periods under the PAR1 scenario, a significant difference (see Figure 13).

**Figure 13: PAR1 difference vs PAR50 on 1 March 2018**

![Figure 13: PAR1 difference vs PAR50 on 1 March 2018](source: Cornwall Insight)

The change was introduced to act as an incentive for parties to balance their contracted position, and to see parties rewarded if they are able to respond to market conditions and provide flexibility to the system. Ofgem published analysis around this in August 2018, finding that market participants are more likely to go long (over contract) due to the risks with being short.

The stated design objectives of the EBSCR were ensuring the right level of security of supply, increasing the efficiency of electricity balancing and ensuring compliance with the EU target model. This defines several market design elements such as market efficiency, trading across borders and financing to increase the physical capacity of interconnectors.

Ofgem’s review concluded that imbalance prices had fallen overall as participants had tended to go longer, but this also masked the half-hourly volatility of imbalance prices. A marginal cost-reflective price is only effective if parties can accurately predict exposure and access hedging products, which can offset the risks they face.
4.5 Potential suspension of the MMO

Ofgem unexpectedly added to uncertainty for electricity wholesale participants when in August it issued notice of the potential suspension of the Market Making Obligation (MMO). The MMO is a key element of Secure and Promote (S&P), the regulator’s programme to improve electricity wholesale market access implemented in 2014. The S&P aimed to address concerns that levels of liquidity in the wholesale market had been persistently low, which had affected the ability of suppliers to hedge their positions.

The potential suspension of the MMO signalled an important shift in regulatory policy that could have significant impact on the market. While the vertically integrated model is clearly breaking down, smaller suppliers in the market have reasonably argued for the maintenance of the MMO, and for more granular products to be introduced that enabled more effective hedging. There was, among these suppliers, concern that if the MMO were suspended trading levels would not be maintained. Other market concerns were raised regarding bid-offer spreads widening that would expose parties to other costs when closing out positions and that, ultimately, confidence in price discovery would be diminished.

Any suspension of the MMO would alter wholesale trading dynamics and require hedging strategies, credit, and risk controls to be revisited. The indicated suspension of the MMO is presently on hold. On 6 November Ofgem confirmed that it would not suspend the MMO during 2018.

4.6 Price cannibalisation

Summer saw low-carbon generation primarily from renewables technologies dominate electricity production, likely setting a trend for the future. However, we suggested that reductions in achievable wholesale revenues at times when there is high renewables output would present growing challenges for the delivery of subsidy-free wind and solar power projects.

This is known as price cannibalisation, the depressive influence on the wholesale electricity price at times of high output from intermittent, weather-driven generation such as solar and wind. The absence of fuel costs makes these generators competitive in wholesale markets when they operate, with high volumes of production squeezing out capacity from higher priced conventional plant that must also recover capital costs. This results in lower cost, more efficient thermal plant setting prices, and in the not too distant future periods where no thermal plant is operating in the market at all.
The result is low or sometimes negative wholesale power prices, within-day and also on the
day-ahead markets, correlated to high levels of output from one or more intermittent
sources of renewable generation. The greater the proportion of output on the system to
meet demand from intermittent generation at any given time, the greater this effect
becomes.

We predicted the cannibalisation effect would act to, and will continue to, put downwards
pressure on wholesale prices year-on-year and that there would be a growing divergence
prices captured by intermittent technologies and the baseload price. As renewable levels
look set to keep rising, several questions around this theme remain as we end the year –
especially with the suspension of the Capacity Market – as to what the effects may be on
the wider wholesale market and trading behaviours of participants, and what the projected
level of volatility means for the point at which different sources of flexibility become
economically viable.

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**Insight Paper 6**

Price cannibalisation is the depressive influence on the wholesale electricity price at
times of high output from intermittent, weather-driven generation such as solar,
onshore and offshore wind.

The absence of fuel costs makes solar and wind competitive in wholesale markets
when they operate, with high volumes of production “squeezing out” capacity from
less efficient and higher cost conventional plant. Without fuel costs renewable plant
can continue to receive revenue even where the wholesale price becomes negative,
as subsidy is paid whenever the stations are generating. The effect is therefore low
or sometimes negative wholesale power prices, correlated to high levels of output
from one or more intermittent sources of renewable generation. The greater the
fraction of output on the system to meet demand from intermittent generation at
any given time, the greater this effect becomes.

Cornwall Insight modelling in our *May 2018 Insight Paper* shows that for a
representative 10MW onshore wind project the cannibalisation effect will reduce
wholesale revenues by 34% in 2031 compared to 2018. Solar power is also
significantly affected by cannibalisation. A representative 5MW standalone solar
project will experience wholesale market revenues reducing 22% from 2018 by
2031.

The paper poses questions that need to be considered by policy makers, such as:
will intermittent renewables be financially viable without subsidy? How will projects
be financed in the absence of subsidies or substitute revenues? And what does the
projected level of volatility mean for the point at which different sources of flexibility,
particularly battery storage, become economically viable?
4.7 Alternative routes to market explored

Another growing trend last year has been much greater emphasis on alternative generator routes to market, chiefly through subsidy-free models such as corporate Power Purchase Agreements (PPAs).

The RO has closed to new investment (bar some exceptions for stations eligible for grace periods) and the FiT regime effectively closes to new capacity from April 2019, leaving only the CfD open for subsidised large-scale low-carbon generation. These changing market dynamics have led to the growth of renewables PPAs throughout the year.

During 2018 competition in the PPA market was greater than ever between offtakers, with generators able to take advantage of very low discounts on the value of their commodity, driven lower by a choice of more than 40 potential PPA providers. The length of PPA contracts, previously 15 years, also decreased, with generators able to agree to shorter-term, fixed price contracts. This is particularly suited to new entrant suppliers at the smaller end of the scale, representing an alternative to the wholesale market, establishing in-house trading activities or outsourcing services. In summary, the range of contracts on offer from a wider pool of providers enabled greater market access for generators of different scale and risk appetite during the year.

There was also a healthy emerging corporate PPA market (CPPA) – a direct PPA with a creditworthy end user – as developers explored more creative solutions to developing without subsidies. Typically, a traditional PPA has been a longer contract that does not provide long-term price stability due to output being paid against a market reference price. A CPPA allows developers to bring a project to market without subsidies and offering a long-term route to market with wholesale price certainty and a buyer with a strong credit rating.

During the year we witnessed significant interest in CPPAs from developers, particularly for onshore wind and solar. Large corporates in particular showed a growing interest in sustainable operations, with renewables proving an attractive prospect.