Part of Drax Group

Third Party Costs newsletter

Issue 13 – August 2020

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Introduction

Since our last issue in October 2019, some significant events – not least the COVID-19 pandemic – have affected the energy industry and specifically Third Party Costs (TPCs).

With the coronavirus causing major changes to normal daily lives and economic activity, the impacts included UK electricity demand falling by as much as 14.3% as lockdown began. This should be no surprise, since many factories, offices and other workplaces (including shops, clubs, restaurants and so on) closed to help stop the spread of the virus between employees and their customers.

The shape of UK demand changed too, as the rapid shift to home-based working moved demand away from the traditional morning and evening peaks. These are where domestic and business demand would, under normal circumstances, overlap resulting in peak consumption.

The drop in demand put extra stress on operating the electricity network. In response, National Grid ESO took various actions to help maintain system stability as periods of unprecedented low demand combined with excess generation from renewable sources. For example, the operator paid Sizewell B nuclear power station to reduce its output during summer 2020, and launched a new "footroom" service.

This service pays distributed generation to stop exporting during periods of low demand; National Grid ESO also raised an urgent modification to constrain (as a last resort) the same generators if required. In addition, the operator increased the forecast cost of balancing the system for 2020/21 by £430m, which will have a direct impact upon the Balancing Services Use of System (BSUoS) costs that are one of the TPCs.

The fall in world demand for oil resulting from COVID-19 led to negative prices for the US oil futures contract for the first time in its trading history. When the May contract expired in mid-April, the lack of physical storage for oil triggered a panic, with oil trading as low as -$40/barrel.

In the UK, we saw the lowest monthly average day-ahead prices in 12 years. A mild winter, plus healthy gas supplies, had led to an over-supplied system where renewables output could dictate the electricity price on any given day. There was a particularly interesting example on 23 May, which saw the first ever negative daily average price on the N2EX index (with 17 consecutive hours of negative prices). This occurred on a particularly sunny and breezy Saturday.

In our previous newsletter, we discussed the impact of a decline in national demand – and the likely impacts upon TPCs. While some charges are set in advance, others – such as BSUoS, Contracts for Difference (CfD) and Small Scale Feed-in Tariff (ss-FiT) – aren't. Instead, they use outturn demand figures to determine each supplier's market share, and this determines the amount they have to pay. With the charging base reduced and the costs increased, there's been an increase in unit rates for these charges.

While there's a possibility that local or national COVID-19 outbreaks (and the resulting lockdowns) could occur, the future for the UK remains uncertain. This makes any considerations that shows the future for the whole of the UK is uncertain, since similar outbreaks could occur anywhere at any time – leading to similar lockdowns. All this makes any considerations about future demand scenarios more complex than usual. However, we've assessed a broad range of outcomes when preparing this edition of our TPC newsletter.

Executive Summary

- COVID-19 has had a broad-ranging effect on the energy industry, with the most significant being the drop in demand materially reducing the charging base.
- Contracts for Difference (CfD) costs ballooned in 2020's first half, with a record (time weighted average) outturn cost of £7.58/MWh and £7.84/MWh for Q1 and Q2 (excluding GEEs), respectively. However, the Department for Business, Energy and Industrial Strategy (BEIS) approved a £75,110,169 loan to the Low Carbon Contracts Company (LCCC), effectively reducing the overall Q2 cost by £1.307/MWh. This loan amount has been deferred to Q2 2021.
- Energy supplier SSE proposed a Connection and Use of System (CUSC) modification (CUSC Mod CMP345) that suggested deferring the additional BSUoS costs arising from COVID-19 that are incurred in 2020/21 into the 2021/22 charging year. The Office of Gas and Electricity Markets (Ofgem) approved a £15/MWh cap between 25 June 2020 and 31 August 2020. Our initial forecast assumes this adds £0.02/MWh into 2021/22 costs.
- Since the approval of CMP345 British Gas has raised CMP350, this proposes to reduce the cap from £15/MWh to £5/MWh until 30 September 2020. Costs will continue to be deferred into 21/22 with a maximum cap of £100 million. A decision is excepted imminently.
- Ofgem approved a proposal by Scottish and Southern Electricity Networks (SSEN) to build a 600MW sub-sea electricity transmission link from Shetland to mainland Scotland. This is subject to receiving sufficient evidence by the end of 2020 that the 457MW Viking Energy Wind Farm project planned for Shetland is likely to go ahead; this recently secured funding.
- Ofgem has launched an investigation into delivery and operation of the Western high-voltage direct current (HVDC) sub-sea cable, as there are significant concerns around its late delivery – as well as its operational reliability due to frequent outages.
- Ofgem's investigation into the power cuts of 9 August 2019 found several parties at fault. Hornsea One Ltd (a windfarm co-owned by Orsted) and RWE (Little Barford Combined Cycle Gas Turbine – CCGT) agreed to pay out £4.5 million for not remaining connected after the lightning strike. UKPN paid out £1.5 million after a technical breach of rules, because Ofgem ruled that customers were re-connected prematurely.
- Ofgem issued the industry an annual levelisation correction for FiT Year 9 (April-18 to March-19) in light of some challenges faced during the initial calculation and due to a small number of suppliers reporting inaccurate data. This resulted in an additional £0.004/MWh change for FiT Year 9 consumption.
- Q2 2020 (April - June 2020 or Q1 of FiT Year 11) out-turned at £9.88/MWh (£2.52/MWh higher than estimated). This increase was driven by reduced eligible demand as result of COVID and high renewable output (from both solar and wind farms).

Make-up of a bill

The Government's charges under the former Levy Control Framework (LCF) and Control for Low Carbon Levies (CLCL), plus other charges, are likely to form an increasing proportion of end users' bills.

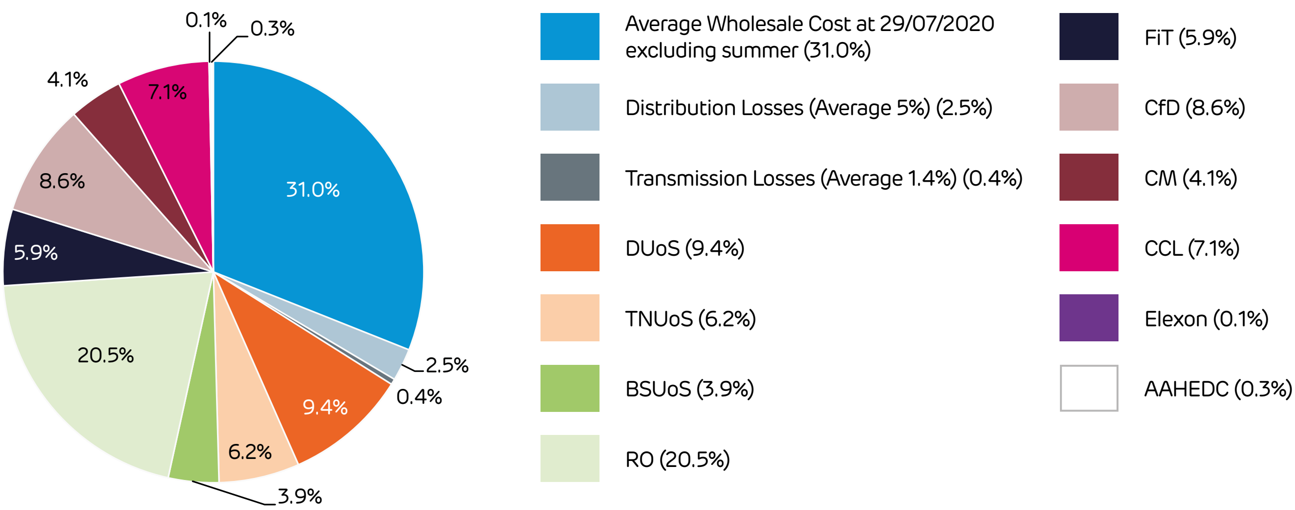
Please be aware DUoS and TNUoS charges can significantly vary from customer to customer, the below are portfolio averages.

Having included a similar breakdown in the previous newsletter, we've updated the figures below. You should only use these figures for indicative purposes.

	Charge (£/MWh)	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Energy	Energy Average Wholesale Cost at 29/07/2020****	35.59	43.24	46.23	48.35	48.78
Losses	Distribution Losses (Average 8%)	2.85	3.46	3.70	3.87	3.90
	Transmission Losses (Average 1.4%)	0.50	0.61	0.65	0.68	0.68
Distribution/ Transmission	Distribution Use of System (DUoS)	10.82	10.73	10.80	11.55	12.37
	Transmission Use of System (TNUoS)	7.10	6.31	7.31	7.42	7.54
	Balancing Service Use of System (BSUoS)*	4.45	4.10	4.28	7.71	8.34
Levy Control Framework charges	Renewables Obligation (RO)	23.52	24.20	24.58	24.85	25.28
	Levy Control Feed in Tariff (FiT)	6.73	6.58	6.79	7.04	7.27
	Contracts for Difference (CfD)*	9.92	11.62	13.29	14.32	14.99
Other charges	Capacity Market (CM)	4.74	1.98	1.51	3.04	4.06
	Climate Change Levy (CCL)**	8.11	7.75	7.91	8.06	8.22
	Elexon	0.08	0.08	0.08	0.08	0.08
	Assistance for Areas of High Electricity Distribution Costs (AAHEDC)	0.30	0.43	0.44	0.46	0.48
	Total	**114.71**	**121.09**	**127.57**	**137.43**	**141.99**

* National Balancing Point (NBP) ** Haven Power forecast from 2022/23 onward ***all figures rounded 2dp **** - Summer-20 uses the price from 31/03/2020

Cost Breakdown for 2020/21



Targeted Charging Review (TCR)

Network companies such as National Grid ESO, and the regional electricity distribution companies – Distribution Network Operators (DNOs), and Independent DNOs (IDNOs) recover their costs through a mixture of tariffs. They base these tariffs on each customer's connection type, capacity and location and split them into 'Residual' and 'Forward looking' charges. The TCR focuses on the 'residual charges' that recover the fixed costs of providing existing network infrastructure.

In November 2019, Ofgem confirmed it would proceed with the TCR and that the BSUoS elements would take effect in 2021. The Transmission Network Use of System (TNUoS) and Distribution Network Use of System (DuoS) will take effect in 2022. However, some within the industry want Ofgem to align the TCR with the start of RIIO-2 (Revenue = Incentives + Innovation + Outputs). This is the next set of network price controls, due to start in April 2023.

The TCR also aims to align smaller distributed (embedded) generators and larger generators by removing the residual TNUoS charge currently paid only by larger transmission-connected generation. In addition, Ofgem confirmed that suppliers would be charged BSUoS on their gross import demand, from April 2021. This effectively removes the BSUoS embedded benefit covered under CMP333.

In terms of TNUoS, Ofgem will introduce a capacity-based daily charge that should see the peak Triad element reduced to 5-10% of the total charge. (Triads are defined as the three highest half-hourly periods of demand separated by 10 clear days.) The majority of TNUoS costs will be recovered within the new residual element. We expect this to add £4.50/MWh for 12-month contracts, or £2.25/MWh for 24-month contracts, starting in either October 2021 or October 2020. **We anticipate further information and clarity by the end of this year.**

This means companies previously able to avoid TNUoS charges by reducing their demand (or using on-site generation) during the Triads, following implementation, will be unable to do so. This is seen as a key deliverable for the scheme, as the effect was to effectively offload these costs onto other customers.

We anticipate a similar change for DUoS charges: a greater proportion of the residual costs will shift from the Red/Amber/Green tariffs currently charged on unit rates to daily or standing charges. Again, we expect this to reduce costs for those currently unable to avoid peak consumption periods.

A set of bandings will determine the costs of the new residual charges, although the details aren't yet finalised. However, they're likely to be based around agreed capacity for half hourly metered sites. There'll be a process to identify the correct banding for customers and Line loss Factor Classes (LLFCs) will be used operationally to deliver the bandings.

Transmission Network Use of System (TNUoS)

TNUoS charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. Non-Half Hourly (NHH) users are charged on net demand, based on their average consumption between 4 and 7pm in kWh. Half hourly users are charged based on their demand over the three Triads each year between November and February. Triads are defined as the three highest half-hourly periods of demand separated by 10 clear days.

Since the last newsletter:

- National Grid has published the 2020/21 tariffs. On average these outturned 2% lower than we expected and were broadly in line with the 2019/20 tariffs. The exceptions were South Western and Southern Scotland, which increased by 2.4% and reduced by 6.5% respectively.
- Our 2021/22 forecast has reduced by 14%. This can be attributed to an increase in the proportion of revenue to be recovered from transmission connected generators, thereby reducing the cost for demand consumers by £240m when compared to 2020/21.
- It's highly likely National Grid will under-recover revenue in 2020/21 as a result of COVID-19 reducing demand during the upcoming Triad season (the tariffs have currently been published). Any shortfall will be recovered in 2022/23, which we've increased by £92m – equivalent to a 3.5% under-recovery of revenue in 2020/21.

Here are our projected year-on-year (YOY) increases for TNUoS, shown as a range of possible outcomes. However, the impacts of TCR and demand reduction may alter this somewhat, with those customers less able to avoid peak charges likely to make some savings in the new methodology.

	2020/21	2021/22	2022/23	2023/24	2024/25
TNUoS High Case		-7.18%	22.80%	5.38%	5.55%
TNUoS Middle Case	Actuals	-11.20%	15.94%	1.47%	1.67%
TNUoS Low Case		-14.71%	9.52%	-2.64%	-2.50%

It's worth highlighting that following the exit of 12 suppliers from the market over the past year, National Grid may seek to recover defaulted TNUoS costs from future tariffs.

Distribution Use of System (DUoS)

DUoS charges are paid to the Distribution Network Operator (DNO). Each supply meter is on a network run by the DNO for that relevant geographical area, and there are 6 DNOs operating across 14 regions in the UK. DUoS charges cover the cost of installing, operating and maintaining a safe and reliable electricity supply within each DNO region.

Since our last newsletter, October 2019's Distribution Connection and Use of System Agreement (DCUSA) reports have been updated for the 2021/2022 charging year. This means that the actual tariffs are available for 2020/21 and 2021/22. For the most up to date and relevant insight, we suggest comparing these with the current tariffs.

DCP268

Ofgem approved DCP 268 in April 2019. This modification aligns the charging structure for all low and high voltage demand customers (including domestic) to a three-rate, time of usage charge commonly known as Red/Amber/Green. In theory, this also aligns users with NHH meters to those with HH.

The modification also consolidates generation tariffs, by combining intermittent and non-intermittent tariffs. As a result, the existing tariff structure bands reduced from 33 to 16 (a substantial change) from April 2021 onwards.

Beyond 2021/22

Using the DNOs' revenue estimates and the most recent data available from the DCP 066 statements, we project future average tariff (year-on-year) increases below (these exclude those with Extra High Voltage - EHV - meters).

However, there may be some individual deviations when the TCR takes effect in the 2022/23 charging year. We consider it likely that the DNOs will under-recover in 2020-21 due to reduced demand during the COVID-19 lockdown, although the 2022/23 tariffs have not yet been published:

	2020/21	2021/22	2022/23	2023/24	2024/25
DUoS High Case	Actuals*	Actuals*	7.88%	14.19%	14.45%
DUoS Middle Case			0.70%	6.88%	7.13%
DUoS Low Case			-5.81%	-0.23%	0.00%

*Actual rates are known – charges for individual customers will vary depending on geographical location, connection type and usage pattern.

Balancing Services Use of System (BSUoS)

Calculated half hourly, BSUoS charges are imposed equally on generators and suppliers. The charge recovers the cost (to the System Operator, National Grid) of operating and balancing the electricity system; it also includes the cost of managing the system voltage, frequency, operating reserve and reactive power.

2019/20

Since our last newsletter, BSUoS charges have continued to outturn higher than normal for Dec-19 to Mar-20. A milder winter reduced chargeable demand by about 5%, while higher-than-normal wind speeds increased constraint costs by around 36%, when compared to same period last year.

There's also been an outage (from 10 January to 7 February) to the HVDC Western link between Scotland and north Wales. This has further increased constraint costs, as excess power was unable to flow from Scotland to the UK. The net effect was an increase in the BSUoS £/MWh charge from £2.90/MWh in 2018/19 to £3.44/MWh in 2019/20. Higher BSUoS charges are another unfortunate result of especially low demand and high renewable output.

CMP 308

CMP 308 proposes the removal of the liability to pay BSUoS charges from GB transmission. The cost is currently recovered equally across demand and generation (apart from interconnectors) and this proposal effectively multiplies the £/MWh charge for GB consumers by approximately 1.7 times.

This proposal is currently under the scope of the Second Balancing Services Charge Taskforce, which has been considering who should pay BSUoS and how the costs are recovered.

However, since the wholesale market price is expected to reduce (with generators no longer paying BSUoS), the effect would be cost neutral for consumers in the long run and to fix the charge in advance. A range of implementation dates are under consideration, from October 2021 (highly unlikely) to October 2023.

CMP 333

This modification is a result of the TCR decision, and is expected to be implemented from Apr-21. This will change how suppliers are levied BSUoS (i.e. from net demand, as it is at present, to gross demand), removing the benefit from embedded generators. We anticipate more information soon.

CMP 281

This modification, approved in May 2020, has the effect of removing BSUoS charges from imported electricity storage facilities (e.g. pumped hydro plants and batteries) from April 2021. Currently, these facilities pay BSUoS for imported and exported electricity. While this will have a small effect on overall BSUoS costs, it should reduce the overall utilisation cost when called upon by the ESO.

CMP345

During May 2020, National Grid increased its BSUoS forecast for 2020/21 by £430m or £0.96/MWh. The increase was concentrated across the summer months as a result of expected COVID-19 actions, and lower eligible demand due to lockdown and reduced economic activity.

Due to this, SSE proposed CUSC Mod CMP345: a suggestion to defer the additional BSUoS costs arising from COVID-19 incurred in 2020/21 into the 2021/22 charging year. SSE felt that suppliers and generators (or indeed National Grid) could neither forecast nor expect this cost. The result, SSE argued, was that suppliers would under-recover from fixed price contracts agreed before the pandemic.

The working group considered various solutions and Ofgem decided to implement an option proposed by National Grid ESO. This caps the half hourly BSUoS charge at £15/MWh between 25 June 2020 and 31 August 2020. If costs exceed £15/MWh, the additional costs will be deferred into 2021/22.

Our initial analysis suggested the deferral could total around £13m, therefore increasing 2021/22 by £0.02/MWh – significantly less than originally expected. If this had been backdated to include April and May, the deferral would have been £16.5m.

2020/21

Since the approval of CMP345 British Gas has raised CMP350, this proposes to reduce the cap from £15/MWh to £5/MWh from 1st of August until end of September 2020. Costs will continue to be deferred into 21/22 with a maximum cap of £100 million.

On average, BSUoS charges have subsequently outturned at £4.86/MWh for April 2020 and £6.24/MWh for May 2020, 1.5 times – or between £1.70 and £2.50/MWh – higher than originally expected. At the time of writing in July 2020, the costs for May 2020 amount to the highest ever in a month. Around one third of them were incurred over that month's breezy and sunny bank holiday weekend (23-25 May).

The table below shows our projected annual BSUoS costs in term of £/MWh of electricity supplied.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
BSUoS High Case	5.50	5.38	7.66	11.80	13.67
BSUoS Middle Case	4.45	4.10	4.28	7.71	8.34
BSUoS Low Case	3.73	2.91	2.95	3.03	3.10

The table below shows monthly out-turn BSUoS costs in term of £/MWh of electricity supplied, along with the annual average, when available.

Actuals £/MWh	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total/Ave
2017/18	1.95	2.29	3.63	2.62	2.84	2.30	3.11	2.11	2.22	1.96	1.60	2.09	**2.35**
2018/19	1.91	2.18	3.00	2.67	2.61	4.48	4.07	2.87	2.56	1.99	2.46	4.05	**2.88**
2019/20	2.86	2.46	3.40	2.75	4.04	3.99	3.79	2.55	3.55	3.82	4.32	3.81	**3.45**
2020/21	4.86	6.24											

RF - Final Settlement Data; SF - Latest Settlement Data

Levy Control Framework & Control for Low Carbon Levies

The Government previously managed its support for renewable energy by imposing levies on suppliers, which - in general - they passed on to their customers. Suppliers did so by adding an amount to customers' bills and by including forecasted costs within the prices of offered tariffs.

The amount of funding was capped through a budget – known as the Levy Control Framework (LCF) - that set the cap while making sure that renewable targets were met.

Spending under the LCF was originally expected to increase from £3.2bn in 2013/14 to over £7bn by 2020/21, in 2011/12 prices. This would cover the costs of the Renewables Obligation (RO), small scale Feed in Tariff (ss-FiT) and the Contracts for Difference Feed in Tariff (CfD-FiT) schemes.

However, the LCF was vastly over budget due to the 'build and accredit' model of the ss-FiT and RO schemes. Both proved very attractive to investors due to the predictable and lucrative subsidy received.

Having announced the end of LCF in its 2017 Spring Budget, the Government introduced its replacement in that year's Autumn Budget: the Control for Low Carbon Levies (CfLCL). This policy states that there'll be no new low carbon electricity levies until the burden of legacy LCF levies (including planned and current CfD capacity) begins to fall. It's anticipated that this will happen around 2025, when older FiT and RO sites begin to decommission or to see their subsidy expire.

Renewables Obligation (RO)

Before it closed to all new generation in 2017, the RO was the main support framework incentivising the generation– and associated construction – of large-scale renewable electricity in the UK. Eligible generators receive a prescribed amount of Renewables Obligation Certificates (ROCs) for every MWh of renewable generation.

Suppliers fulfil their requirements by presenting ROCs to Ofgem. Alternatively, they can pay Ofgem a published Buy-Out price per ROC for any shortfall. Funds arising from Buy-Out payments are usually channelled into a "recycling" arrangement and distributed to eligible renewable generators.

Licensed suppliers are obliged to source an increasing proportion – the "Renewables Obligation" – of electricity from renewable sources, or else paying a published Buy-Out price. The Obligation is specified each October for a given April- March year to follow (the Compliance Period, or CP).

Since our last newsletter, ROC forecast remains relatively unchanged – although future eligible demand has reduced due to the COVID-19 shutdowns. However, our 2021/22 middle case forecast has reduced by £0.60/MWh, driven by the record low levels of UK inflation - recently hitting a four-year low in June 2020.

In February 2020, the 2020/21 buy-out was published at £50.05/MWh; £0.20/MWh lower than our estimate in the previous edition of this newsletter. This sets the charge at £23.57/MWh for 2020/21, £0.03/MWh lower than in 2019/20 – the first year on year reduction ever. ROC production is now in a phase where volumes will stabilise and then reduce, since the scheme has now been fully closed for three years, and some of the older accredited stations' subsidy will expire.

The table below shows outturn and our projected RO costs in terms of £/MWh of electricity supplied. We've based this on a valuation of ROCs at projected Buy-Out prices, and for customers who don't qualify for the Energy Intensive Industry (EII) exemption.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
RO High Case	Actuals	25.88	27.52	29.13	31.01
RO Middle Case		24.20	24.58	24.85	25.28
RO Low Case		22.64	22.05	21.24	20.56

Small Scale Feed in Tariffs (ss-FiT)

The ss-FiT subsidy is recovered from suppliers and paid to smaller generators of eligible low carbon and renewable power. Many of these generators use photovoltaic (PV) panels on rooftops, although a significant proportion of the power comes from smaller solar and wind farms in the countryside.

Ofgem administers the ss-FiT scheme, collecting a sum from each supplier based on their market share in each quarter. In the September following a given financial year, an annual reconciliation – or "truing up" – occurs, when more information is available about generation levels and suppliers' market shares. The principal factors affecting the charges to suppliers in any period are the levels of insolation (the amount of sunshine) and the installed PV capacity.

On 18 December 2018, and following consultation, BEIS confirmed its decision to close the FiT scheme to new applicants from 1 April 2019 (barring several exceptions). Thanks to cost control measures by BEIS, the scheme's annual costs are now levelling out at around £1.6 billion.

The EII exemption for the ss-FiT scheme came into effect from April 1, 2019 as planned. This had been subject to the European Commission granting state aid approval, which came in late March 2019.

Q1 2020 (January – March 2020 or Q4 of FiT year 10) has out turned at £4.65/MWh. This was £0.18/MWh higher than expected. The majority of this (£0.16/MWh) was due to demand out-turning 2.4TWh lower than expected, primarily due to mild weather and COVID-19 will have contributed to this at the end of the quarter (restrictions applied from 23/24th March).

We now also have an indicative annual figure (subject to annual reconciliation in September 20) of £6.17/MWh for 2019/20, this is based on £1,578m total costs under the scheme and 255.7TWh of eligible volume. This is £0.16/MWh lower than our last newsletter and is primarily due to costs out-turning slightly lower than expected due to a slight reduction in sunshine hours. In the last 2 years we have seen large changes in costs and demand during the annual reconciliation due to supplier errors and/or failures so this value could further change.

Q2 2020 (April - June 2020 or Q1 of FiT Year 11) out-turned at £9.88/MWh (£2.52/MWh higher than estimated). This increase was driven by reduced eligible demand as result of COVID and high renewable output (from solar farms).

In terms of our annual 2020/21 figure, this has increased by £0.07/MWh since our last newsletter. FiT costs have remained flat; however our view of national demand has reduced by 3.5% due to COVID-19 - as previously mentioned there is huge uncertainty around future restrictions making forecasting annual consumption extremely difficult.

Ofgem issued the industry an annual levelisation correction for FiT Year 9 (April-18 to March-19) in light of some challenges faced during the initial calculation and due to a small number of suppliers reporting inaccurate date. This resulted in an additional £0.004/MWh change for FiT Year 9 consumption.

The table below shows our projected annual FiT costs in term of £/MWh of electricity supplied.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
ss-FiT High Case	7.98	7.42	7.89	8.44	9.00
ss-FiT Middle Case	6.73	6.58	6.79	7.04	7.27
ss-FiT Low Case	6.03	5.84	5.87	5.90	5.92

Seasonal fluctuations in FiT levels are evident, and swings of over £1/MWh from quarter-to-quarter are quite common. The table below shows quarterly costs since 2017.

£/MWh	Q2 (Apr-Jun)	Q3 (Jul-Sep)	Q4 (Oct – Dec)	Q1 (Jan-Mar)	Value including Annual Rec
2017/18	5.96	6.81	4.57	3.74	5.19
2018/19	6.31	7.39	5.17	4.14	5.58
2019/20	7.11	8.03	5.19	4.42	
2020/21	9.88				

Contracts for Difference Feed in Tariff (CfD-FiT)

The CfD-FiT scheme is the framework designed to encourage new low carbon power generation in the UK. It replaces the Renewables Obligation (RO) mechanism, which has now closed, as the main vehicle for long-term investment into renewable electricity.

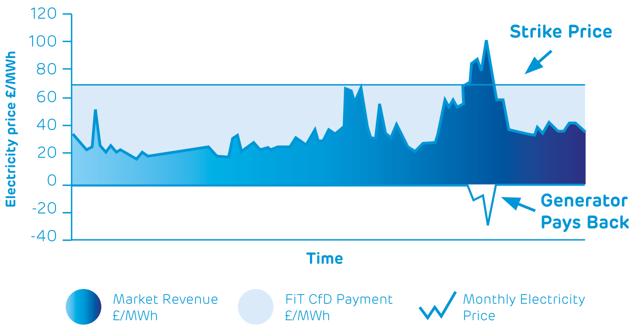
Generators enter into a contract with the Low Carbon Contracts Company (LCCC) under the auspices of the Department for Business, Energy and Industrial Strategy (BEIS). The generators sell their renewable power into the wholesale market as usual, but crucially pay or receive an additional amount (i.e. top-up) for each MWh. This amount is equal to the difference between an individually agreed fixed "strike" price and the relevant market price (the "reference" price) for that MWh.

Therefore, if the market price is below the strike price, the generator receives a "top up" price for the energy produced. However, the generator must make a payment if the market price is above the strike price in any period. The arrangement means that generators can rely on receiving the strike price for their output.

Before each quarter, the LCCC estimates how much Contracts for Difference (CfD) generation will occur in the following three months. It then uses each agreed strike price to calculate total net payments to all CfD-FiT generators.

This will be used to compute an ILR - Interim Levy Rate rate; a guide to how much the CfD-FiT scheme will cost per MWh for that quarter. The LCCC will charge suppliers the interim rate for their accredited volume each day. At the end of each quarter, the LCCC will reconcile with each supplier the daily difference between the interim rate and actual cost of the CfD scheme.

As the CfD-FiT scheme's costs are dependent upon wholesale prices, predicting costs (or income) for generators is difficult. Should wholesale prices increase, scheme costs will fall as lower top-up payments are required. The opposite holds true if wholesale prices fall. Wind generation also affects scheme costs; if reduced wholesale prices and increased generation production drags wholesale prices lower, eligible generators will require more top-up to reach their strike price.



Source UK Government White Paper, July 2011, licensed under the Open Government License v1.0

The LCCC will also recover its operational costs (from suppliers) through an Operational Cost Levy - set at £0.0614/MWh for 2020/21. As the administrative scheme costs continue to rise (from around £15m in 2017/18 to over £17m in 2020/21), the Operational Cost Levy will follow suit - albeit from a low base.

(Please note that all strike prices in the following section are in 2012 money).

Since the last newsletter, LCCC published the results of the third CfD auction. The company procured 5.775GW of capacity from 12 generators, starting in charging years 2023/24 and 2024/25 with an average strike price of £40.63/MWh.

Off-shore wind (including remote island wind) accounted for around 95% of the capacity with a strike price of £39.65/MWh, down from £62.14/MWh in the previous auction. This is notably similar to current wholesale prices, although these wind farms will receive a (i.e. top-up) based on the day-ahead wholesale prices (intermittent market reference prices). These tend to be significantly lower when wind generation is strong, so we anticipate some top-up costs from the wind farms – even if wholesale prices average at around this level.

In September 2019, LCCC initially set the levy rate for Q1 2020 at £5.85/MWh. However, it outturned at £7.82/MWh when including Green Excluded Electricity certificates (GEEs) volume. The levy rate outturned about £2.00/MWh higher than the interim levy for several reasons. The particularly windy and mild quarter coincided with the start of COVID-19 restrictions and a slump in wholesale prices, boosting CfD generation costs over a reduced charging base. The 2019/20 outturn is expected to be around £6.55/MWh (excluding operational costs) once GEEs are submitted over the next three quarters.

Q2-2019

National demand has outturned significantly lower for Q2-20 due to COVID-19 – an unforeseen event when LCCC initially set the Q2 20 interim levy rate (ILR). In addition, LCCC didn't take the opportunity to adjust the rate before or during the quarter – with the result that the company will not recover enough funds to pay generators in this quarter.

In May, BEIS agreed to provide a loan for 80% of the shortfall in costs recovered, rather than increase the ILR mid-quarter. The latter action would have put additional pressure on suppliers and consumers (at a time when many households and businesses are operating on reduced income).

Contracts for Difference (CfD) costs ballooned in 2020's first half, with a record (time weighted average) outturn cost of £7.58/MWh and £7.84/MWh for Q1 and Q2 (excluding GEEs), respectively. However, BEIS has approved a £75,110,169 loan to the Low Carbon Contracts Company (LCCC), effectively reducing the overall Q2 cost by £1.307/MWh. This loan amount has been deferred to Q2 2021.

The table below details the average daily Levy Rate for the CfD scheme, at the time of publishing (July 2020).

Quarter	Total Costs (£)	Total Demand (MWh)	Scheme cost £/MWh
Q1 18	205.11	82.07	2.50
Q2 18	180.95	64.55	2.80
Q3 18	229.22	62.93	3.64
Q4 18	287.86	75.26	3.83
Q1 19	281.95	76.83	3.67
Q2 19	326.15	63.66	5.12
Q3 19	383.37	61.39	6.24
Q4 19	503.24	77.86	6.46
Q1 20	595.20	78.56	7.58
Q2 20*	450.91	57.49	7.84

* Loan amount included

We constantly review our forecasts, considering several factors. These include power prices, possible changes to commissioning dates, revisions to wind forecasts, and adjustments for implementation date and exempt volumes falling under the Energy Intensive Industry (EII) scheme. As part of the LCCC's commitment to transparency, it publishes forecasts for the coming 15 months – along with the assumptions underpinning estimates – on its website/dashboard.

Below, we've set out our projections of CfD-FiT costs for the next five years. On average since our last newsletter, wholesale market prices have reduced by around £3.00/MWh (when comparing Summer-21 to Summer-24) in addition to more capacity being added.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
CfD-FiT High Case	12.12	13.55	15.54	17.30	18.74
CfD-FiT Middle Case	9.92	11.62	13.29	14.32	14.99
CfD-FiT Low Case	8.12	10.25	11.31	11.85	11.93

Capacity Market (CM)

The introduction of a Capacity Market (CM) within the Electricity Market Reform (EMR) arrangements makes sure that the UK has sufficient capacity on the grid to cover peak demand. Historically, this was an issue on winter weekdays.

Under the CM, reliable generating sets (e.g. coal-fired or gas-fired plant) that aren't remunerated through other schemes* are eligible to commit to being available at peak times in the future, in return for a payment. This also applies to demand that can be reduced with notice. The level of payment is set via an auction process.

* This includes schemes such as Contracts for Difference (CfD) and Renewables Obligation (RO)

Unlike the Levy Control Framework where charges fall across all periods and run from April to March each year, the CM supplier charge runs from October to September. This monthly payment to EMR Settlements Limited is based on each supplier's expected market share during periods of high demand (4pm-7pm, Monday to Friday, from November to February). Once the outturn supply of each supplier is known in May, the charge is reconciled back over the remaining months.

Capacity Market suspension

The Capacity market was reinstated in late October 2019, after the European Commission confirmed that the GB Capacity Market scheme was compatible with EU state aid rules. This followed the EC completing its formal investigation, after a legal challenge to the fairness of the scheme in March 2019. This triggered the collection and payment of deferred capacity market payments in respect of the Standstill Period (the suspension).

Given that future auctions were suspended during the Standstill Period, three auctions took place during early 2020 to bring the scheme back up to speed.

- In January 2020, the 2022/23 T-3 auction cleared at £6.44/kW, with 45.1GW of capacity clearing. This is the lowest clearing price - when excluding T-1 auctions, and no large-scale new build cleared.
- In February 2020, the 2020/21 T-1 auction cleared at £1/kW, with 1.02GW of capacity clearing. The capacity gaining agreements was significantly above the target capacity of 0.3GW, due to a lower than expected clearing price.
- In March 2020, the 2023/24 T-4 auction cleared at £15.97/kW, with 43.749GW of capacity clearing.
- There will be two auctions in early 2021 as usual, a T-4 and T-1 auction.

We continue to review our assumptions on future CM clearing prices based on our internal analysis. Our estimates of future CM costs, including a Haven Power inflation forecast, are in the table below. We also publish our view of the costs for purely the peak periods – for customers with flexible load, or on-site generation that can offset demand– this could be an opportunity to reduce costs.

Cost in £/MWh, over customers' annual consumption (EAC)	2020/21	2021/22	2022/23	2023/24	2024/25
CM High Case	5.18	2.27	1.80	3.38	6.71
CM Middle Case	4.74	1.98	1.51	3.04	4.06
CM Low Case	4.62	1.88	1.38	2.74	1.36

Cost in £/MWh, 4pm-7pm, Mon-Fri, Nov-Feb	2020/21	2021/22	2022/23	2023/24	2024/25
CM High Case	126.08	53.99	44.02	82.78	164.68
CM Middle Case	114.96	47.71	36.32	73.49	98.46
CM Low Case	110.47	44.51	32.84	65.24	32.32

Balancing and Settlement Code (BSC)/ELEXON

Each BSC party compensates National Grid Company (NGC) for the trading and settlement duties it's performed, paying its share of the costs based on the volume supplied/traded. Effectively, the more involved the BSC party, the larger the share it must pay.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
ELEXON	0.08	0.08	0.08	0.08	0.08

Climate Change Levy (CCL)

The CCL is an energy tax that encourages business users to reduce carbon emissions and improve energy efficiency. Before August 2015, Levy Exemption Certificates (LECs) backed generation from renewable sources (such as biomass or wind) and customers on renewable energy were exempt from paying CCL. Since that date, the charge has applied to all business users. However, energy-intensive businesses that enter into a Climate Change Agreement (CCA) with the Environmental Agency pay a reduced CCL rate. The CCA is a voluntary agreement to reduce energy use and carbon dioxide (CO2) emissions.

CCL for the year starting 1 April 2021 was confirmed at 0.775p/kWh for electricity, a decrease of 4.4% from the current year.

This is the second year-on-year decrease since a steep rise from April 2018 to April 2019. In contrast to this, the equivalent charge for natural gas has increased year-on-year.

At the time of writing (July 2020), there are no further rates published for the years after 2021 and our own forecasts reflect likely increases due to inflation.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
CCL	8.11	7.75	7.91	8.06	8.22

Assistance for Areas of High Electricity Distribution Costs (AAHEDC)

AAHEDC is levied on all suppliers, with the funds passed on to Scottish Hydro Electric Power Distribution Limited. This reduces the Distribution Use of System (DUoS) charges for the North of Scotland.

Tariffs are published by 15 July each year and take effect from 1 April retrospectively. Ofgem had previously published its intention to include a proportion of the costs for the Extended Interim Energy Solution for Shetland from April 2019 – a figure we calculated at £0.20/MWh.

However, this was delayed and National Grid set the final tariff at £0.30446/MWh for 2020/21. The expectation now is for implementation from April 2021 as part of the Hydro Benefit Replacement Scheme and Common Tariff Obligation consultation published in February 2020.

£/MWh	2020/21	2021/22	2022/23	2023/24	2024/25
AAHEDC	0.30	0.43	0.44	0.46	0.48

For further information on Third Party Costs, please contact your Account Manager.

Haven Power's Third Party Costs newsletter is one of the ways we help our customers and consultants stay informed about changes to non-energy costs.

Your feedback tells us how valuable you find this information - so please don't share it with any party not associated with Haven Power.

Thanks.

Haven Power Ltd
The Havens
Ransomes Europark
Ipswich IP3 9SJ

A better use of energy

www.havenpower.com

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