ESO BSUoS Forecast Update

21st May 2020

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Exec Summary

The lockdown associated with Covid-19 has had an unprecedented impact on the operation of the electricity network. As we have discussed at our weekly stakeholder webinars, low demand increases the actions we have to take to manage the system. These actions cost money, and as they are recovered through BSUoS, we know that our stakeholders want as much transparency as possible. Our current forecasts show a £500m increase in BSUoS costs for this summer compared to last summer (May – August).

We normally provide updated BSUoS forecasts to the market a month ahead. As the current crisis is increasing BSUoS costs for market participants we are now providing more frequent forecasts, and projecting out for a longer period. This will help market participants manage their commercial positions.

Based on stakeholder feedback, we are also publishing details of our BSUoS forecasting methodology. This document provides information on how we normally calculate BSUoS and how we have adapted this methodology for the current crisis. The methodology is based on a robust analysis, underpinned by a set of valid assumptions. However, the forecasts should only be seen as an indicative view, and we have provided details of the uncertainties within the forecasts.

In order to ensure safe and reliable operation of the electricity system during sustained periods of low demand, we introduced new products and services. There is legitimate interest in the benefit of these services. This document provides an estimate of the BSUoS costs had we not introduced these new products and services. Our analysis shows that these new products and services will deliver a benefit of around £200m.

Low Demands

Since the onset of Covid19, GB electricity demands have reduced on average by between 11% and 16% across the day, with minimum demands at times down by even more – we are expecting a minimum (transmission level) demand of c. 14GW over the late May bank holiday weekend. These unprecedented low demands are causing challenges as to how we secure the power system over the Summer period.

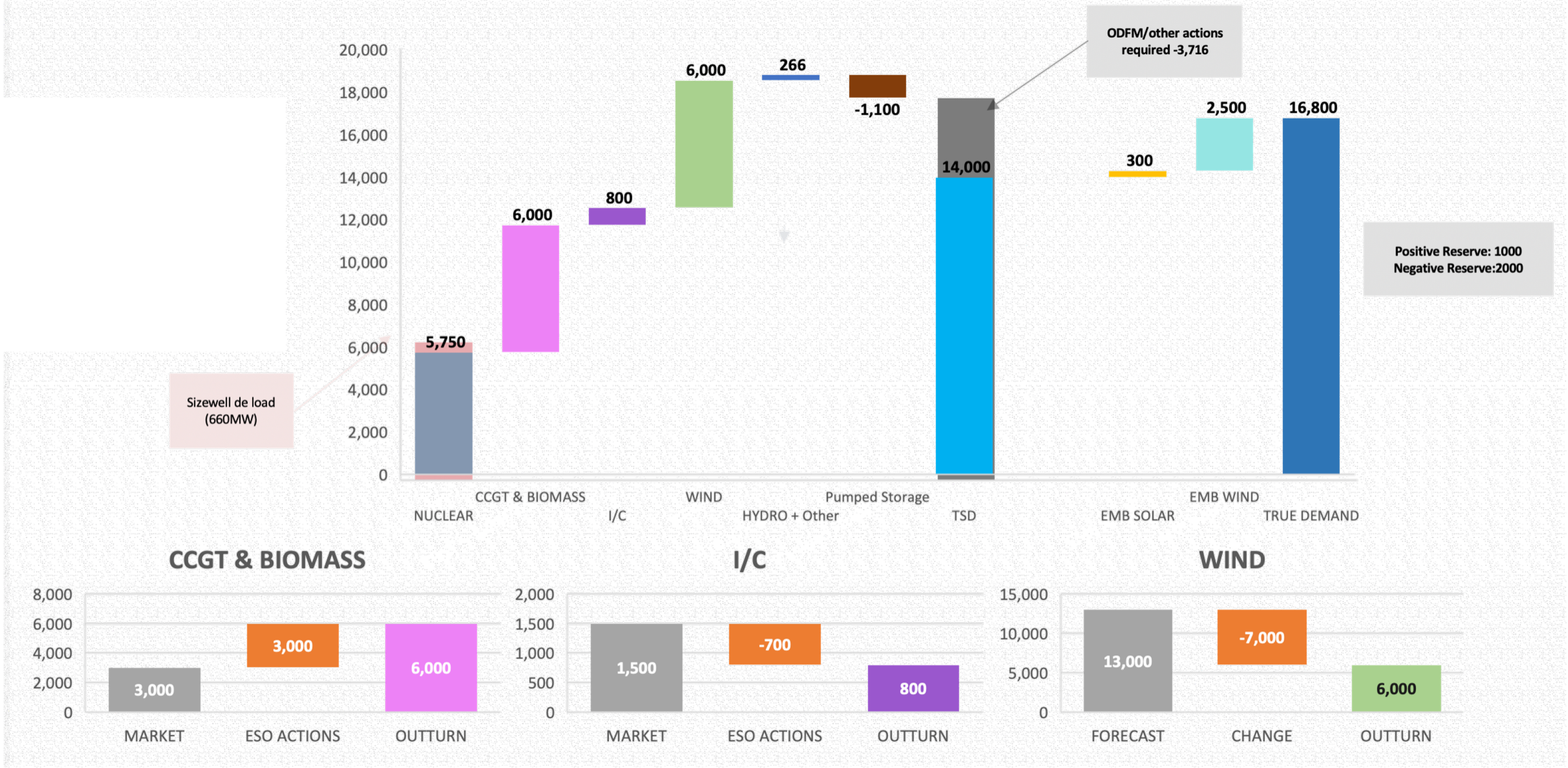
These reduced demands have materially changed the energy mix with renewables, inflexible nuclear generation and generation connected to the distribution network making up a larger share of energy supply. This change has made system operation more challenging, particularly managing the stability of the transmission system.

The renewable generation will self dispatch in line with weather conditions, following the incentives of their subsidy support arrangements, rather than demand or wholesale market pricing. Typically, they do not currently provide the required system services. This is compounded as when they are running, they displace other power stations which could provide services to manage voltage, stability, frequency, thermal and restoration.

To manage this The ESO must create 'space' to synchronise generation which can provide the required services, and ensure sufficient downward flexibility is available to respond to fluctuations in demand. This requires larger than normal intervention in the market.

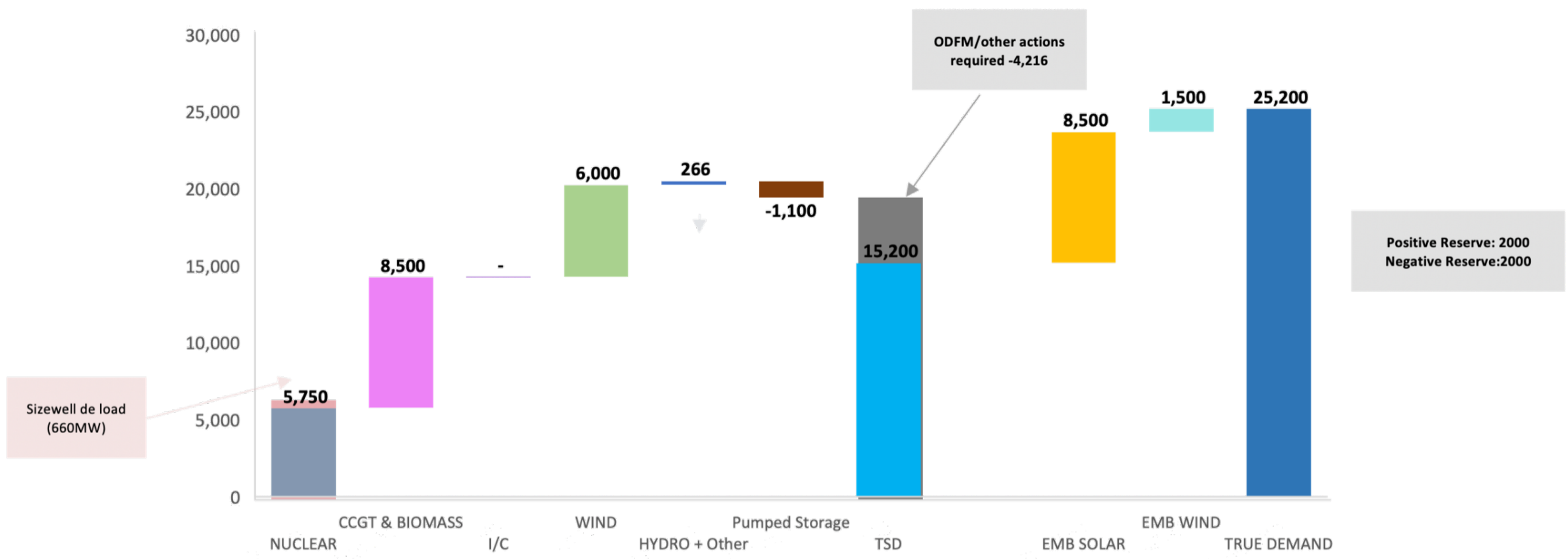
The charts on the following two slides demonstrate the volumes of actions that the ESO would likely be required to take

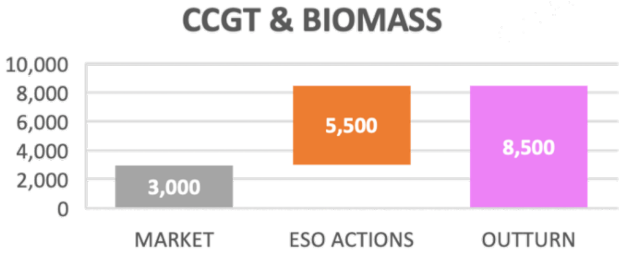
Minimum Overnight demand - Planning

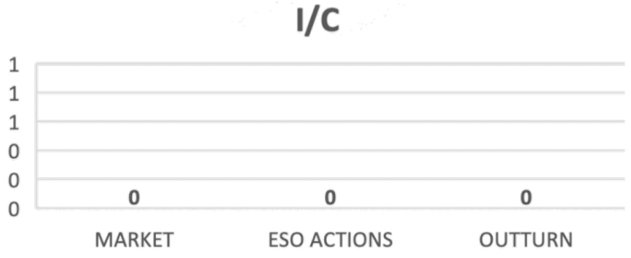


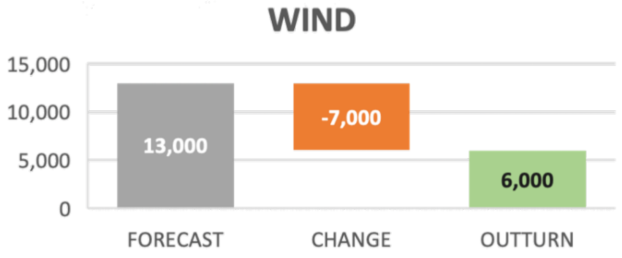
Please note numbers are for indicative purposes only

Minimum Daytime Demand - Planning









Please note numbers are for indicative purposes only

A note on our BSUoS updates published 15th May 2020

On May 8th we provided two forecasts, both for May 2020 with demands impacted by COVID-19 factored in:

1. A forecast assuming 'normal' seasonal weather; and
2. A forecast assuming more 'extreme' weather

Based on stakeholder feedback, on 15th May we provided 2 updates:

1. We evolved our May 8th forecasts into a single most likely view, using a range of weather scenarios to determine a best view of weather for May 2020. This update is labelled **Impact on BSUoS due to COVID-19 low demands – Excluding new services**. This update shows expected BSUoS had the ESO developed no new approaches to manage the low demands and is provided for purposes of comparison
2. We provided a new main forecast, labelled **BSUoS Forecast for Summer 2020 – Including new services** which uses the updated best view of weather and overlays the forecasted costs and benefits of using the new tools and services available to the ESO.

£m	Outturn	Forecast date				
		April	8th May		15th May	
	2019	Normal Weather	Normal Weather	Extreme Weather	BSUoS Forecast for Summer 2020 – including new services	Impact on BSUoS due to COVID-19 low demands – excluding new services
May	64.4	101	177.3	276.7	166	174
June	89				207.7	268.1
July	71.1				214.9	272.7
August	108.7				237.7	324.7
Total	333.2				826.3	1,039.5

All of the Forecasts can be found on the ESO data portal here

Deep Dive- BSUoS Forecast Methodology

Our standard methodology for BSUoS forecasting is based on using historical data with inputs based on minimal expected changes. A different approach is required to capture the significant changes brought about by COVID-19 demand suppression.

The key driver in increased costs is from the increased intervention at low demand points due to demand suppression as detailed in the previous slides. The volume and costs of these actions at low demands were not present in the pre-COVID-19 BSUoS forecast. We have assumed similar costs to previous years at demands greater than 18 GW.

Step 1 Develop a cost per hour of operating at very low demand points.

Using operational tools we created the expected costs of managing the system at low demand levels (less than 18 GW down to 13 GW) without new services.

This is effectively solving for each demand period the requirements for voltage, stability, frequency, thermal and restoration whilst also optimising in line with the previous slides.

We then repeated the activity but this time offset the costs with the use of new services.

Two datasets were created to reflect the different actions required to manage overnight and afternoon minimums.

The previous slides demonstrate that minimums which are overnight and daytime have different volumes of actions

These costs are sensitive to the volume of actions required and the costs of the actions taken.

Step 2 – Create a model of potential demands

Using historic weather variation data we created a large number of weather sensitivities.

We took these sensitivities and the current demand forecasting models to create a separate demand forecast for each sensitivity.

For each of these demand forecasts we discounted all the demands above 18GW as the costs associated will already be included in the baseline forecast in step 3.

Then using the costs per hour we created in step 1 we compiled a cost forecast for each sensitivity.

The mean value of all the sensitivities was then used as the additional costs expected from continued demand suppression.

Step 3 – Add the additional costs into the baseline BSUoS forecast

The additional costs were added onto the baseline costs, including the Sizewell contact costs, from previous forecasts. Uncertainties exist in these forecast; these are reviewed overleaf.

Known uncertainties with the methodology

In the following slide the assumptions used to create the forecast are detailed. Areas where sensitivities around values have not been developed but would create a change in the forecast are;

- Demand – The demand forecast is based current demand suppression brought about by current COVID-19 lockdown conditions. The demand forecast is the largest driver of the costs, we believe this is pessimistic for the overall summer but appropriate for the forecast at this point.
- Weather – The weather is a critical driver in the demands we forecast, whilst we have run over 30,000 weather sensitivities to generate the mean there still remains uncertainty in the weather which will actually happen. A further slide details the spread of the sensitivities
- Costs of actions - We have used single figures for the costs at each demand point of adding CCGTs, trading on interconnectors, reducing output on wind farms through bids and a forecast of the cost of the new ODFM service. These numbers are based on experience from managing very low demands during April. These costs are the second largest driver in uncertainty in the forecast and should be considered pessimistic.
- Market response – We have assumed a more pessimistic view of how the market responds to low demands, with no market response to self manage wind output combined with low level of CCGT self dispatch and interconnector imports. If market response was more favourable the volume of actions by the ESO and the costs are expected to decrease. Again this should be considered as pessimistic.
- Volume of actions – We have created a number of models and approaches to calculate the required number of actions to secure the five operability challenges at low demands. The required system needs at these low demands are the area of the forecast with which we have the highest certainty. Although the volume of actions to move to this position is dependent upon the market response as detailed above.

Overall there is potential upside (reduced BSUoS forecast costs) in the demand, cost of actions and market response. There is some potential downside (increased BSUoS costs) in the effects of the weather or further demand suppression compared to what has already been seen.

Next Steps

The weekend of May 23/24 will be some of the lowest demands experienced this summer based on lockdown position, general demands, bank holiday and the forecasted weather. Using the cost and volume of actions taken over this weekend will provide us another set of data to review and refine our assumptions as appropriate.

Step 1 – Costs Per Hour - Daytime

Assumptions used in the modelling

ESO actions by fuel type		Demand in 3b periods (GW)					
		13	14	15	16	17	18
Assumptions	CCGT market %	15%	20%	25%	30%	50%	70%
	CCGT offer	£80	£80	£80	£80	£80	£80
	Wind bid	-£150	-£150	-£150	-£100	-£70	-£60
	IC trade	-£200	-£100	-£50	-£50	-£10	-£10
	New service	-£200	-£200	-£200	-£200	-£200	-£200
	Forecast wind	7500	7500	8000	10000	10000	10000
	Forecast IC	500	500	500	1000	2000	2000
	Nuke load	5648	5648	5648	5648	5648	5648
	IC exports	-500	-500	-500	-500	-1000	-1000
	Pumps	-556	-556	-556	-556	-834	-834

CCGT market [%] is the market provided proportion of required CCGTs and Biomass required as a %

CCGT offer [£] is the expected average cost of the offers to gain access to the unit for syncing

Wind Bid [£] is the expected average cost of the bids to achieve the desired volume reduction

IC trade [£] is the expected average cost the price to achieve the desired volume reduction

New service [£] is the forecast average cost of the service to achieve the desired volume reduction

Forecast wind [MW] is the expected wind levels at the proposed demand levels

Forecast IC [MW] is the expected forecast interconnector flows

Nuke load [MW] is the expected nuclear output

IC Exports [MW] is the required export requirement

Pumps [MW] is the expected requirement

Step 1 – Costs Per Hour – Daytime

Actions and costs for managing daytime minimums – without new services

ESO actions by fuel type		Demand in 3b periods (GW)					
		13	14	15	16	17	18
CCGT	Required	6,118	5,958	5,958	5,688	5,518	5,518
	Market dispatch	918	1,192	1,490	1,706	2,759	3,863
	ESO actions	5,200	4,766	4,469	3,982	2,759	1,655
	ESO cost	£416,024	£381,312	£357,480	£318,528	£220,720	£132,432
Wind	Forecast dispatch	7,500	7,500	8,000	10,000	10,000	10,000
	Max wind	900	2,187	3,383	4,579	6,274	7,470
	ESO actions	-6,600	-5,313	-4,617	-5,421	-3,726	-2,530
	ESO cost	£990,000	£796,950	£692,550	£542,100	£260,820	£151,800
Interconnectors	Market dispatch	500	500	500	1,000	2,000	2,000
	ESO actions	-1,000	-1,000	-1,000	-1,500	-3,000	-3,000
	ESO cost	£200,000	£100,000	£50,000	£75,000	£30,000	£30,000
New service	ESO actions	0	0	0	0	0	0
	ESO cost	£0	£0	£0	£0	£0	£0
Total per hour		£1,606,024	£1,278,262	£1,100,030	£935,628	£511,540	£314,232
Net ESO action (MW)		-2,400	-1,547	-1,149	-2,939	-3,967	-3,875

Benefits of new actions

ESO actions by fuel type		Demand in 3b periods (GW)					
		13	14	15	16	17	18
Wind	Forecast dispatch	7,500	7,500	8,000	10,000	10,000	10,000
	Adj Wind/IC bids	-600	-600	-600	-600	-600	-600
	Avoided price	-200	-150	-150	-100	-70	-60
	ESO saving	£120,000	£90,000	£90,000	£60,000	£42,000	£36,000
Total per hour		£1,486,024	£1,188,262	£1,010,030	£875,628	£469,540	£278,232

To read this chart

Top table: Each column shows the cost per hour of managing each different demand level as highlighted in the header.

The **CCGT** rows show the required level of CCGT and Biomass required to resolve operability challenges, expected market dispatch, the ESO actions required to make up the gap and the forecast cost of these actions based on the ESO cost assumptions detailed previously.

The **Wind, Interconnectors** and **New Services** are the actions required to create the space for CCGTs detailed above. They are effectively interchangeable as each MW provides the same benefit. The new service line was left blank as actions on Wind and Interconnectors were seen as similar in cost and volume based on the assumptions above.

This creates a **Total per hour** for managing the system at specific demand points.

Bottom table: Captures benefits from specific contracts, where other operational requirements (and costs) are offset.

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Step 1 – Costs Per Hour - Overnight

Assumptions used in the modelling

ESO actions by fuel type		Demand in 3b periods (GW)					
		13	14	15	16	17	18
Assumptions	CCGT market %	5%	5%	10%	30%	50%	50%
	CCGT offer	£80	£80	£80	£80	£80	£80
	Wind bid	-£80	-£80	-£80	-£70	-£60	-£60
	IC trade	-£200	-£100	-£50	-£50	-£10	-£10
	New service	-£200	-£200	-£200	-£200	-£200	-£200
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Nuke load [MW] is the expected nuclear output

IC Exports [MW] is the required export requirement

Pumps [MW] is the expected requirement

Step 1 – Costs Per Hour – Overnight

Actions and costs for managing overnight low demands – without new services

ESO actions by fuel type		Demand in 3b periods (GW)					
		13	14	15	16	17	18
CCGT	Required	3,738	3,738	3,568	3,348	3,348	2,948
	Market dispatch	187	187	357	1,004	1,674	1,474
	ESO actions	3,551	3,551	3,211	2,344	1,674	1,474
	ESO cost	£284,088	£284,088	£256,896	£187,488	£133,920	£117,920
Wind	Forecast dispatch	7,500	7,500	8,000	10,000	10,000	10,000
	Max wind	3,093	3,990	5,286	6,608	7,505	8,731
	ESO actions	-4,407	-3,510	-2,714	-3,392	-2,495	-1,269
	ESO cost	£352,560	£280,800	£217,120	£237,440	£149,700	£76,140
Interconnectors	Market dispatch	500	500	500	1,000	2,000	2,000
	ESO actions	-1,000	-1,000	-1,000	-1,500	-3,000	-3,000
	ESO cost	£200,000	£100,000	£50,000	£75,000	£30,000	£30,000
New service	ESO actions	0	0	0	0	0	0
	ESO cost	£0	£0	£0	£0	£0	£0
Total per hour		£836,648	£664,888	£524,016	£499,928	£313,620	£224,060
Net ESO action (MW)		-1,856	-959	-503	-2,548	-3,821	-2,795

Benefits of new actions

ESO actions by fuel type		Demand in 3b periods (GW)					
		13	14	15	16	17	18
Wind	Forecast dispatch	7,500	7,500	8,000	10,000	10,000	10,000
	Adj Wind/IC bids	-600	-600	-600	-600	-600	-600
	Avoided price	-200	-100	-80	-70	-60	-60
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This creates a **Total per hour** for managing the system at specific demand points.

Bottom table: Captures benefits from specific contracts, where other operational requirements (and costs) are offset.

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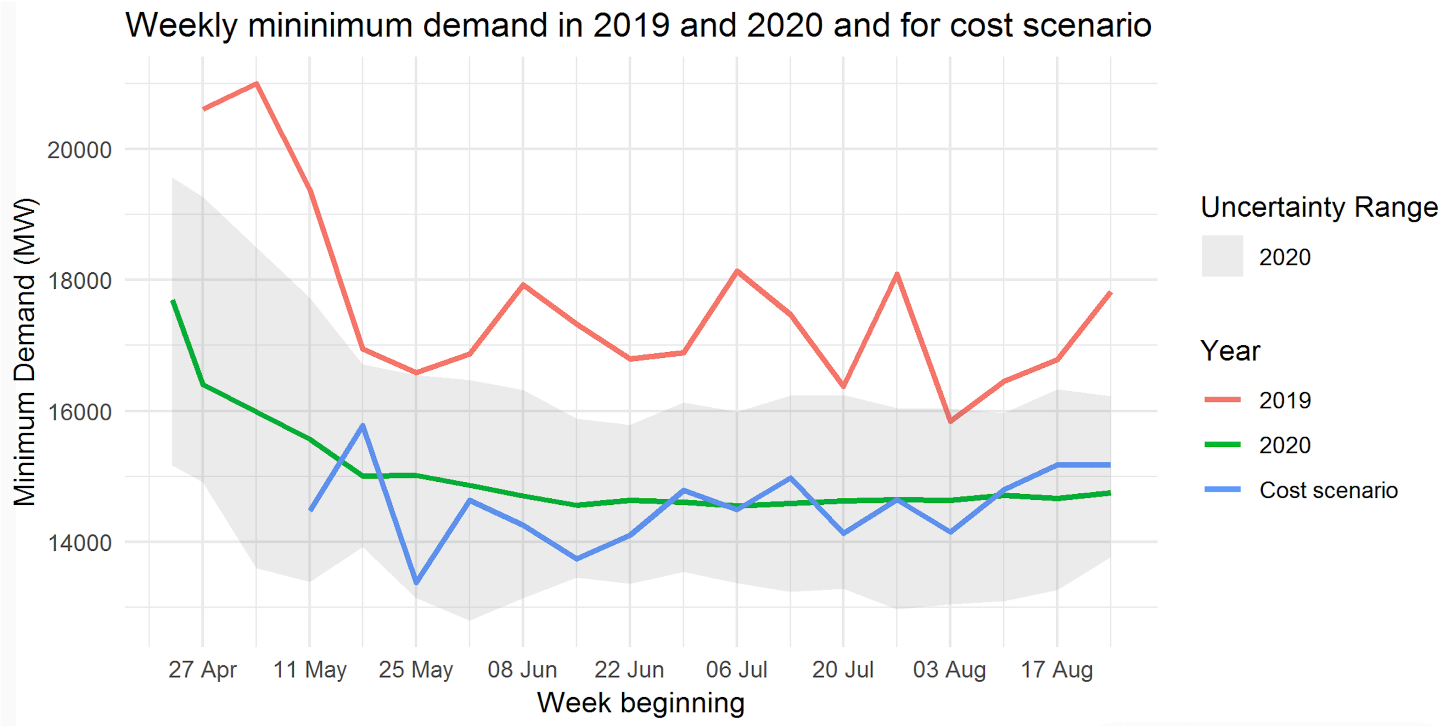
Step 2 – Demand Sensitivities

The process used to create the demand forecasts used the current view of demand out-turns against a set of weather criteria. To expand this and remove some of the weather variability a data set which encompasses 30,000 weather sensitivities was used to create t 30,0000 demand forecasts for the period May to August.

Each data set has half hourly demands for the period of 122 days which is a total of 5,856 settlement periods.

For each of the weather sensitivities the cost data from Step 1 was used to create a total expected increased cost.

Below is the range of potential demand forecast (weekly minimums) which could be used to create the cost mean from the sensitivities. Attached with this presentation is also four demand forecast at a half hourly resolution for reference which could be used to determine the mean.



Costs (£m)

Step 3 Adding the Two Forecasts together

As highlighted at the beginning of this pack. The pre-existing BSUoS forecast contained the expected costs of manging the system with very few periods below 18 GW. Step 2 generated the additional extra costs of managing the system at demands lower than 18 GW and includes the savings from new services. Step 3 adds together the baseline forecast with the additional increased costs from step 2 to create the expected overall BSUoS forecast.

Baseline Forecast + Increased costs from Step 2 = BSUoS Forecast

£m	Baseline with new services
May	121.3
Jun	103.8
Jul	110.4
Aug	120.2

£m	Step 2 Additional costs (£m) with new services
May	44.7
Jun	103.9
Jul	104.5
Aug	117.5

	BSUoS Forecast for Summer 2020 – Including new services
May	166
June	207.7
July	214.9
August	237.7
Total	826.3