

CMP440

Alternative

proposal

2025



Alternative proposal

- **Zones with positive locational TNUoS HH:** Directly use the £/KW figure generated by the TNUoS model (current method – does not change).
- **Zones with Positive locational TNUoS NHH:** $\text{£/KW (from model)} \times \text{NHH TNUoS Model Zonal Demand} / \text{NHH forecast zonal annual demand across 4-7pm}$.
(current method used to convert to p/KWh – does not change)
- **Zones with negative locational TNUoS HH and NHH:** $\text{£k/KW (from model)} \times \text{Total TNUoS model Zonal Demand} / \text{Total forecast zonal annual demand across all periods}$.

Comparison of Tariffs

		2029/30 CMP440 WACM 1		
Demand Zone		HH Triad (£/kW)	NHH 4-7 (p/kWh)	Negative (p/kWh)
1	Northern Scotland	-		-1.022482
2	Southern Scotland	-		-0.789048
3	Northern	-		-0.229480
4	North West	-		-0.134632
5	Yorkshire	-		-0.074131
6	N Wales & Mersey	-		-0.040215
7	East Midlands	1.400242	0.185345	
8	Midlands	2.834515	0.378736	
9	Eastern	4.321299	0.612771	
10	South Wales	3.29239	0.39369	
11	South East	7.551503	1.086955	
12	London	10.210745	1.145858	
13	Southern	9.147958	1.231638	
14	South Western	5.010471	0.704802	
Demand residual £m		Impact on demand residual	5.91%	

		2029/30 CMP440 revised original		
Demand Zone		HH Triad (£/kW)	HH 4-7 (p/kWh)	NHH 4-7 (p/kWh)
1	Northern Scotland	-	-5.491031	-6.946760
2	Southern Scotland	-	-4.311266	-4.934235
3	Northern	-	-1.368369	-1.524583
4	North West	-	-0.786542	-0.923399
5	Yorkshire	-	-0.437162	-0.497013
6	N Wales & Mersey	-	-0.231053	-0.272421
7	East Midlands	1.400242	-	0.185345
8	Midlands	2.834515	-	0.378736
9	Eastern	4.321299	-	0.612771
10	South Wales	3.29239	-	0.39369
11	South East	7.551503	-	1.086955
12	London	10.210745	-	1.145858
13	Southern	9.147958	-	1.231638
14	South Western	5.010471	-	0.704802
		Impact on demand residual		5.91%

Overall same amount is allocated, but without perverse operational incentives

E.g. Calculation

		A			B			C	D			E
Demand Zone		2029/30			Triad Demand			Revenues by zone £m/Yr	All periods Consumption (TWh)			Tariff Negative (p/kWh)
		Peak (£/kW)	Year Round (£/kW)	Total (£/kW)	HH Triad (GW)	NHH Triad (GW)	Total Triad		HH	NHH	Total	
1	N Scot	-0.52	-50.68	-51.20	0.44	0.94	1.38	-70.87	3.11	3.82	6.93	-1.02
2	Southern Scotland	-1.94	-37.35	-39.29	1.25	1.89	3.13	-123.11	8.02	7.58	15.60	-0.79
3	Northern	-2.50	-10.08	-12.58	1.06	1.31	2.38	-29.90	7.41	5.62	13.03	-0.23
4	North West	-0.14	-6.97	-7.11	1.48	2.38	3.86	-27.46	10.86	9.54	20.40	-0.13
5	Yorkshire	-1.82	-2.15	-3.97	1.52	2.12	3.64	-14.44	10.63	8.84	19.48	-0.07
6	N Wales & Mersey	0.8	-2.97	-2.15	1.01	1.43	2.44	-5.24	7.14	5.88	13.02	-0.04

- Step 1, calculate total revenues by zone $A \times B = C$
- Step 2, divide total revenues by total all periods consumption: $C / D / 10 = E$

* Factor of 10 adjusts for conversion between £m to pence and TWh to KWh

Negative signals relate nearly entirely to Year Round circuits

Demand Zone		2029/30		% Year Round
		Peak (£/kW)	Year Round (£/kW)	
1	Northern Scotland	(0.52)	(50.68)	99%
2	Southern Scotland	(1.94)	(37.35)	95%
3	Northern	(2.50)	(10.08)	80%
4	North West	(0.14)	(6.97)	98%
5	Yorkshire	(1.82)	(2.15)	54%
6	N Wales & Mersey	0.82	(2.97)	138%
Total		(6.09)	(110.20)	95%

- Most of the negative signal relates to year-round circuits.
- Actual savings are based on reduced constraints for year-round. Charging across all demand more reflective than across peak.
- 94.8% on a £/KW basis, 93.4% on a £ basis (i.e. vol adjusted).

Frontier Analysis

...our analysis suggests that updates to the current backgrounds could be appropriate in order to improve cost reflectivity

Cost reflectivity

- The analysis suggests that Year Round and Peak Security type backgrounds are likely to remain relevant, though their representativeness can be improved with changes to specific assumptions.
- If a single background was favoured, a Year Round type scenario could be most appropriate going forward, although this could entail a small reduction in cost reflectivity, relative to two backgrounds. For example, charges would be expected to increase for wind as circuits previously tagged to Peak Security are now tagged as Year Round.
- The marginal benefit of adding a third background is much reduced compared to adding a second background, particularly in 2035.
- Irrespective of whether this analysis is considered to support a change, an update to the backgrounds is likely to be required in future e.g. due to “fixed” generation exceeding demand.

Level of charges

- The impact of using more representative backgrounds appears to be relatively limited, either using two alternative backgrounds or a single alternative.
- This suggests that without a change to the fundamental flow from North to South, changes to backgrounds may only have a limited impact on final charges.
- In addition, if the €2.50/MWh cap is binding then the adjustment tariff may also reduce the impact of changes further.

Predictability of charges

- The predictability analysis suggests that there are no clear implications for year to year volatility from applying one (Year Round) or two backgrounds, which may suggest no material change in predictability of the tariffs.
- Although moving to a single background would remove one area of uncertainty in the tariff calculations (i.e. the tagging of circuits to a particular background).
- There appear to be volatility implications if adopting only a peak background, however, this would be inconsistent with the cost reflectivity analysis.

...however, our initial view is that the implications of change for the level and volatility of charges may be relatively limited

Frontier Analysis

Demand charges should therefore be set in a manner reflective of the drivers of network cost in each background

Peak charging

- Peak demand is an important driver of network investment for some assets to secure the network at peak
- Therefore charging on the basis of peak demand is likely to remain important for assets tagged as Peak Security
- For the purposes of this work we have assumed national peak demand is a reasonable proxy for peak flows over all Peak Security assets wherever they are located.
- However, it is worth noting that peak demand may vary in timing nationally, suggesting it may be feasible to think about locally determined peak based charges.

Year Round

- Consumption during periods of congestion is an important driver of network investment for some assets.
- Therefore, it is likely to be appropriate to materially change the basis on which Year Round costs are currently charged
- In other words, charges should shift away from peak demand to a measure of consumption during periods of constraints in order to penalise (reward) demand for its role in causing (or alleviating) constraint costs.

In the following sections we consider the options for setting charges reflective of each cost driver.

Basic options for charging year round identifying which hours and allocating year-round costs

Average demand in constrained hours only		
<div><div>1</div><div>Average demand in all hours</div></div> <div><ul style="list-style-type: none">Simple to implementEasy to understandSends minimal (very diluted) operational signalLikely more cost reflective than charging based on peak demandAbstracts from the distinction between consumption during constrained hours (which affects required network investment), and consumption in other hours (which does not)</div> <div>Analogous to a Load Factor style approach</div>	<div><div>2</div><div>Unweighted</div></div> <div><ul style="list-style-type: none">Charges based on average consumption during all constrained hours.Would send only a small operational signal (assuming there are many constrained hours in a year)Sends more targeted cost reflective investment signal but not fully cost reflective.</div> <div>Analogous to a “Constrained Load Factor” style approach</div>	<div><div>3</div><div>Weighted by a metric</div></div> <div><ul style="list-style-type: none">Charges based on weighted average consumption in constrained hours.<ul style="list-style-type: none">Options for weighting approach discussed in slide 26May send a modest operational signal in most periods but may send stronger incentives when constraints are higher.In principle sends a more targeted and cost reflective investment signal.</div> <div>Analogous to a “Constrained Load Factor” style approach with further adjustment</div>

We assess each of these options in the following slides

CP30 extracts

2030 clean power pathways run with:	Further Flex and Renewables		New Dispatch	
	unabated gas % in 2030	constraint costs in 2030, £billion	unabated gas % in 2030	constraint costs in 2030, £billion
The 2024 transmission network (assuming no further deployment)	8.1%	£12.70 billion	7.7%	£10.90 billion
The network currently expected for 2030 (not including AENC/ATNC/SCD1)	6.6%	£7.79 billion	6.2%	£6.58 billion
The network required for clean power, including the three critical projects being delivered in 2030	4.97%	£3.57 billion	4.99%	£2.84 billion
The network if all 7 further projects were accelerated to 2030	4.1%	£1.86 billion	4.1%	£1.07 billion

£60bn network infrastructure required to reach CP30 is economically justified primarily in terms of reduction of constraints – not the cost of meeting system HH peak.

CP30: Flexibility is important

“Clean power offers an opportunity to transform how residential, industrial and commercial consumers engage with their energy use. Consumer participation in actively shifting demand in line with signals from flexibility services, alongside the adoption of smart home devices and good operating practices will provide vital support to the network.”

“Our analysis implies a broad hierarchy of flexibility options for times when there is insufficient clean power to meet demand: Demand side flexibility, responding to innovative tariffs or other retail market offerings, would typically come first, reducing peak demand.”

- Demand flexibility is required for to decarbonise the grid
- Should be vary wary of introducing any operational signals that will interfere with efficient flexible dispatch or represent a barrier to entry.

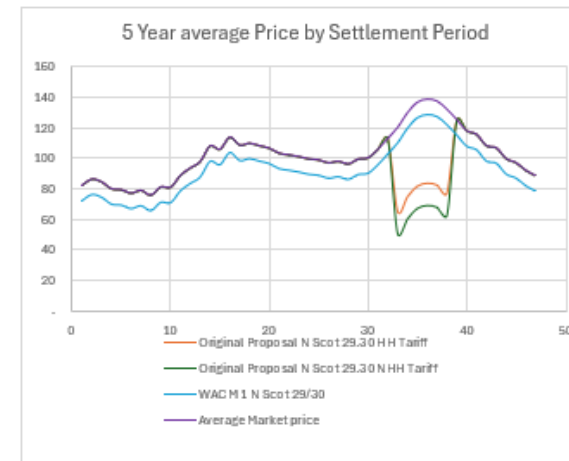
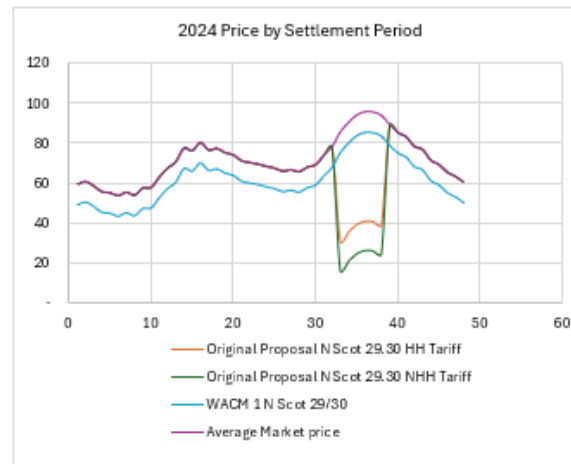
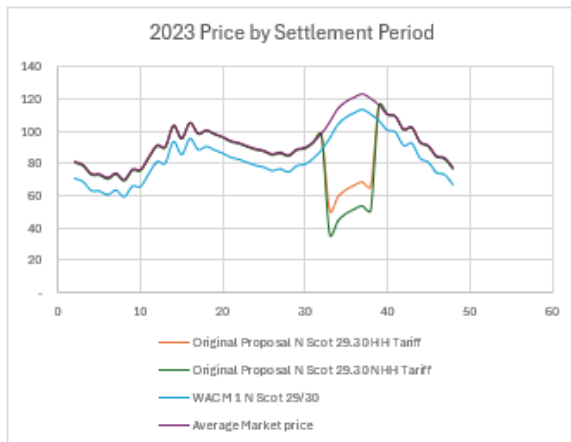
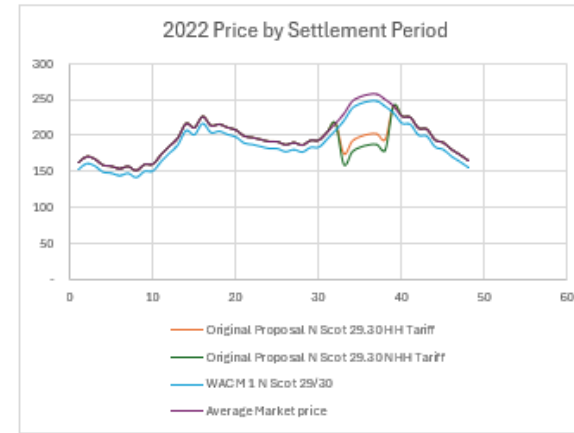
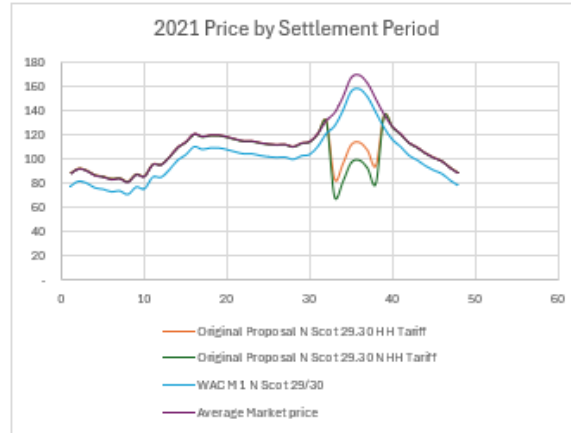
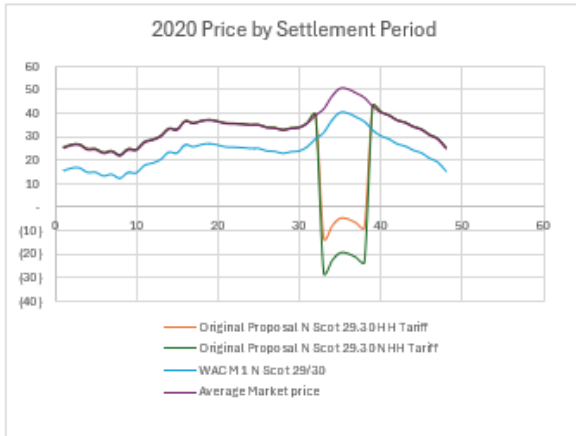
Short run operational signals

Price element	Charging Method	Exemptions
Wholesale Market	Varies by HH	No
Capacity Market	4-7pm Weekdays Nov-Feb	EII (100%)
AAHEDC	£/MWh over All demand	no
BSUoS	£/MWh over All demand	EII NCC (60%)
RO, FiT, CfD	£/MWh over All demand	EII (100%)
TNUoS residual	£/Site/Year (banded)	EII NCC (60%)
CCL	£/MWh over All demand	Some EIIs / Domestic

NCC discount
set to increase
to 90%

Period	No of HH	Short run operational signal ORIGINAL	Short run operational signal THIS WACM
Non EII Demand			
CMCS periods (4-7pm weekdays Nov-Feb)	515	CMCS rate + Negative locational TNUoS + Wholesale price	CMCS rate + Wholesale price
All other peak periods exc CMCS periods	1,676	Negative locational TNUoS + Wholesale price	Wholesale price
All other periods	15,341	Wholesale Price	Wholesale Price
EII Demand			
4-7pm all days	2192	Negative locational TNUoS + Wholesale price	Wholesale price
All other periods	15341	Wholesale Price	Wholesale Price

In some zones – the operational signal is significant



Operational signal will shift demand to peak periods.

Participation in demand flexibility will be much harder with this operational signal

Alt proposal does not have this barrier

- North Scot original and WACM proposal tariffs applied to historic elexon data

Other points

- Year round circuits are built for constraints – charging year round circuits over peak could significantly over-reward some profiles.
- Charging over peaks means a user that only used power over 13% of peak periods, could be significantly over rewarded. (i.e. a baseload customer would avoid 7.7x the constraints). Could be even higher, if taking into account constraints are *less* likely over peak.
- Worse – near perfect flexible demand that reduced output over peaks, would not see any of the signal, despite being very good for the system.
- Only takes 15 periods to predict a triad
- Flexible demand in Scotland will shift demand to peak periods far more often than if just a triad were used. Instead of 15 HHs per year, more like 1600-2200 (depending on if they are an EII).

Summary

- More practical – no distortive market signals
- Better aligned with outputs of TNUoS model (i.e. spreads Year Round circuits over year round demand)
- Better aligned with actual investment drivers, i.e. value of constraints avoided is modelled in Economic Appraisal prior to transmission investment recommendations being made
- Supported by external analysis and recommendation (i.e. Frontier)

Thank you

More info at statkraft.co.uk