Workgroup Report

CMP315: TNUoS Review of the expansion constant and the elements of the transmission system charged for and

CMP375: Enduring Expansion Constant & Expansion Factor Review

CMP375 seeks to amend the calculation of the Expansion Constant & Expansion Factors to better reflect the growth of and investment in the National Electricity Transmission System (NETS), CMP315 is a related but separate change and seeks to review how the Expansion Constant is determined such that it best reflects the actual NETS costs as a result of locational decisions taken by generation and/or demand.

Modification process & timetable

Step	Stage	Date
1	**Proposal Form**	16 April 2019 (CMP315); 17 June 2021 (CMP375)
2	**Workgroup Consultation**	14 April 2022 - 17 May 2022
3	**Workgroup Report**	20 July 2023
4	**Code Administrator Consultation**	01 August 2023 – 30 August 2023
5	**Draft Modification Report**	21 September 2023
6	**Final Modification Report**	11 October 2023
7	**Implementation**	01 April 2025

Commented [CH(1]: Updated implementation date to 2025 as discussed in Workgroup. Action on all to consider impacts of this.

Commented [CH(2R1]: Timeline to be updated

Have 5 minutes? Read our Executive summary

Have 20 minutes? Read the full Workgroup Report

Have 30 minutes? Read the full Workgroup Report and Annexes.

Status summary: The Workgroup have finalised the CMP315 proposer's solution, the CMP375 proposer's solution as well as 1 alternative solution to CMP375. They are now seeking approval from the Panel that the Workgroup have met their Terms of Reference and can proceed to Code Administrator Consultation.

This modification is expected to have a: High impact on all Users who pay TNUoS charges, ESO, Onshore and Offshore Transmission Owners

Governance route	Standard Governance modification with assessment by a Workgroup	
Who can I talk to about the change?	**Proposers:** CMP315: Nick Sillito nsillito@peakgen.com Phone: **07491434518** CMP375 : Paul Mott Paul.mott1@nationalgrideso.com	**Code Administrator Chair**: Paul J Mullen Paul.j.mullen@nationalgrideso.com Phone: **07794537028**

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Executive summary

CMP375 seeks to amend the calculation of the Expansion Constant & Expansion Factors to better reflect the growth of and investment in the National Electricity Transmission System (NETS), CMP315 is a related but separate change and seeks to review how the Expansion Constant is determined such that it best reflects the actual NETS costs as a result of locational decisions taken by generation and/or demand.

What is the issue?

CMP375 - As approved under CMP353, the CUSC currently specifies that the Expansion Constant (EC) and associated generic onshore Expansion Factors (EF) are currently fixed at the value used in 2020/21 plus relevant inflation for each following year. Without establishing and implementing an enduring solution for the calculation of the EC and EFs there is a risk that the charging methodology will not appropriately reflect the incremental costs of the system to Users.

The issue identified by CMP315 is related but specifically seeks to change the current approach (rather than the more fundamental review that CMP375 has been raised to look at) and specifically the inputs that currently go into the calculation of the EC and EFs.

What is the solution and when will it come into effect?

Proposer's solution for CMP315 and CMP375:

Category	CMP315 Original	CMP375 Original
Works Included	Extend the scope of works used in the calculation of the Expansion Constant to include: **New Circuits** - Construction of a new Circuit **Circuit Reinforcements** - Reusing existing towers but reinforcing conductor **Non-Circuit Reinforcements** - Replacement or enhancement of assets at Substations **Circuit Life Extensions** - Works to keep existing assets in use for longer than originally intended Recalculate and apply a Expansion Constant (EC) or Expansion Factor (EF) value (for each circuit type as per today) applicable from the Implementation Date based on the wider scope of works.	As per CMP315 but excludes **Non-Circuit Reinforcements** - Replacement or enhancement of assets at Substations. The Proposer of CMP375 seeks to instead create 'proxy circuits' to capture substations in the Transport & Tariff (T&T) model.

	Civils Costs - Civil costs associated with overhead towers or underground cables are included, based on generic project profiles as described in STCP14-1 (e.g. assuming no motorway crossing etc) – note that this is the current treatment of civils costs.	
Weighting Methodology	MW km years based weighting – as of today, the EC is calculated as the length weighted average cost of all relevant construction over the previous 10 years with the construction cost in each relevant year indexed by inflation to the current year. For annuitisation, split the cost of reinforcement that creates new capacity (Incremental MW) and new additional life (Incremental life).	As per CMP315
Data	10 years historic data in the first year of implementation, then new data for the most recent year. Each historic project cost datum is inflated up to the correct year. Use previous year's data and apply a "smoothing" factor (13% weighting factor applied per year* for new data, and 87% weighting to the last year's expansion constant for that asset class, with one year's inflation applied to last year's value in this process) to mitigate volatility. If no new build cost data is available in a given asset class, last year's expansion constant for that asset class plus 1 year's inflation is to be used. **Previous 5 years of data makes up 50% of cost (consistent with current methodology where 10 years*	As per CMP315

	historic data = 100% of cost) so 13% is based is on this The new project by project cost approach means that some content in baseline CUSC and accompanying STCP 14-1, requiring processing by the TO of the data which is under baseline on an average basis per asset class, will be removed – the project costs are no longer adjusted for canal, railway crossing etc (see footnotes to the 2 parts of STCP 14-1 appendix C)	

Implementation date: 1 April 2025

Summary of potential alternative solution(s) and implementation date(s):

Alternative Solution(s)	Details	Implementation Date
CMP375 WACM2	**Works Included** – as per CMP375 Original **Weighting Methodology** - Each EC or EF is calculated as a weighted average of cost data based on a set of expected works (a “basket of works”). The basket of expected works will be forward-looking and based on the future works set out in the Transmission Operators’ price control business plans for each voltage level and circuit type. Introduction of MW km to weight the costs of reinforcements. When calculating the representative basket of works, propose to use km weightings as this data is already produced as part of Transmission Operators’ regulatory reporting. **Data** - Up to 30 years of historic data but noting that only 10 years of historic data is available currently i.e the calculation after year 1 is performed each year using last year’s data bundled up with the previous 10 years (without removing the project cost data for projects from the oldest year, Y-10, but rather increasing the overall historical data to 11 years in the second year, 12 years in the third year etc up to 30years in total when it shall then move to a rolling 30years of data) and apply a "smoothing" factor (0.13 smoothing factor for all years and not just for first year) to mitigate volatility.	1 April 2025

Workgroup conclusions: The Workgroup concluded by majority/unanimously that the X solutions better facilitated the applicable CUSC Objectives than the Baseline.

Commented [M(PJ3]: To be updated at Workgroup Vote stage

What is the impact if this change is made?

The expectation of both changes is that they would better reflect the marginal cost of investment on the NETS. There will however be additional data and process requirements on Transmission Owners and Offshore Transmission Owners.

Interactions

CMP375 and **CMP315 -** Given the overlap between CMP375 and CMP315, these Modifications are being developed in parallel but separately. There was always the option to request formal amalgamation of these modifications at a later date if beneficial.

However, although there are lots of similarities between **CMP375** and **CMP315,** the key difference is that **CMP315** includes substations within the works to be factored in when calculating the Expansion Constant and **CMP375** doesn't.

STC

As the EC is calculated using data provided from the Transmission Owners / Offshore Transmission Owners to the ESO for the purposes of charge setting, there will need to be changes to the STCPs and possibly the STC to reflect the data requirements. The draft STCP Modification, PM0124, was presented at October 2022 Panel and will be formally raised at the STC Panel once the CMP315/CMP375 solutions have been fully developed.

The new project by project cost approach means that some content in the baseline CUSC and accompanying STCP 14-1, requiring processing by the TO of the data which is under baseline on an average basis per asset class, will be removed. The project costs are no longer adjusted for canal, railway crossings etc (see footnotes to the 2 parts of existing STCP 14-1 appendix C). This was proposed by the ESO for all three variants and discussed and agreed at the Workgroup.

CATO

STCP 14-1 refers to three named onshore TOs. The ESO rep explained that it cannot be immediately altered to add "CATO" to that list of three, as CATO is not yet defined in the main STC. Once CATO is defined in the main STC, if any of these CUSC mods are passed, the plan is to add CATO to the list, and the fact that the project costs are given as they are with no data adjustments to remove canal, railway crossings etc, makes it easy for CATOs to do this. CATOs will be added later on to the STCP via a simple change. The main changes to STCP 14-1 have been run past STC Panel once in outline, but that is now dated as the CUSC mods have developed. Once the WG vote has taken place and it is clear there are no more WACMs, new STCP 14-1 drafts, one per CUSC mod/WACM, will again be taken to the STC Panel.

TNUoS Taskforce - CMP315 or CMP375 are not within the scope of the TNUoS Taskforce. However, the solutions for CMP315 or CMP375 represent an important building block.

Other Modifications

There was an urge to progress CMP315 and CMP375 as soon as possible especially as Ofgem in their decision on CMP325 noted they expected the ESO to revisit the issue of rezoning alongside the development of any further change to the EC[1]. ESO current plan is to only raise rezoning Modifications once clarity reached on the CMP315 and CMP375 solutions this year, as this is also an issue needing resolution in the light of the planned construction of a lot of new offshore network.

EBR

This modification has no interactions with EBR Article 18 Terms and Conditions.

Terms of Reference

Workgroup Terms of Reference	Workgroup outcome
a) Consider EBR implications	As stated in section above, there are no interactions.
b) Review of the principles of the current methodology	Covered within **Transport and Tariff Model Interpretation – General section**
c) Consider the effect on both TNUoS demand charges and generation charges	Covered within the tariff analysis section
d) Consider any interaction with demand TNUoS tariffs if floored at zero	Covered in Tariff Analysis section
e) Consider in terms of aligning with Recital 63 of EU Renewable Energy Directive (2009/28/EC)	This is no longer relevant as it is no longer explicitly recited in the relevant UK SI.
f) Consider the distributional effect on Consumer tariffs	Covered with the tariff analysis section
g) Implementation timeframes to be considered ahead of the TO RIIO price controls in 2021	Implementation timeframes considered as part of the workgroup meetings. There is no longer any change in the EC approach due on the transition to the new price control, and therefore has no significant impact.
h) Consider interactions with the Transmission license and any cross code impacts especially STC	Cross code impacts are covered in section above. Transmission license interactions - this has been considered and there is a fairly limited interaction. The only interaction that has

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[1] From Ofgem's decision letter of 11 November 2020 "Given the significant interaction between this modification and CMP353, and any future reform to the expansion constant methodology, we would expect NGESO to revisit the issue of rezoning alongside the development of any future change to the expansion constant"

	been found is with the Weighted Average Cost of Capital (WACC) and the overhead factor, and there is no need for any changes as a result of this modification.
i) Be mindful of, and consider, the SCR	Targeted Charging Review Significant Code Review has already been covered by the outcome from Terms of Reference. There are no other interactions to note.
j) Clarify need, as soon as possible, for any external analysis	Covered in Lane and Clark (LCP) analysis section
k) Consider interactions with CMP375	This is covered throughout the Workgroup Report

What is the issue?

CMP375 - As approved under CMP353, the CUSC currently specifies that the Expansion Constant (EC) and associated generic onshore Expansion Factors (EF) are currently fixed at the value used in 2020/21 plus relevant inflation for each following year. Without establishing and implementing an enduring solution for the calculation of the EC and EFs there is a risk that the charging methodology will not appropriately reflect the incremental costs of the system to Users.

CMP315 - The issue identified by CMP315 is related but specifically seeks to reform the current approach (rather than the more fundamental review that CMP375 has been raised to look at) and specifically the inputs that currently go into the calculation of the EC and EFs.

Why change?

The EC, which is an input to the TNUoS charging methodology, reflects the annuitized £/MW/km cost of 400kV overhead line and acts as a multiplier to the 'nodal' TNUoS prices (the relative costs of adding 1MW of generation at each point on the network, or 'node'). The EC directly affects the locational signals that users face and

- High EC values create a sharp locational signal – i.e. increase the strength of the locational price signal.
  - Makes TNUoS charges higher in more expensive zones and more negative in cheaper zones
- Low EC values do the opposite
- If the EC was zero, all the locational charges would be zero

The EC is currently set at the start of each Price Control period and has been (until CMP353 decision explained below) based on projects built in the previous 10 years. It is then adjusted for inflation in each year of the Price Control period.

The GB electricity system is undergoing significant change as it adapts to the challenges of net zero. The methodology underpinning the locational signal for TNUoS charges needs to be robust and consider the changing nature of developments on the NETS compared to when the arrangements were introduced. The EC and EF currently used within the calculation of TNUoS tariffs are currently calculated based on a very limited scope of development to the NETS. As the nature of NETS development and investment has changed over time the number of projects eligible for consideration within calculation of the EC and EFs have shrunk. This means that the development of the NETS may not be accurately captured within the previous calculations and reverting to the prior methodology would not be suitable. It is the contention of the proposers to CMP315, CMP375 and WACM2, that the way new network capacity is added can include reconductoring and reinforcement, rather than just primary new build. The pre-CMP353 method of calculating the expansion constant only took account of the cost of primary new build and ignored the cost data of reconductoring and reinforcement type TO investments. Taking account of the cost data of reconductoring and reinforcement type TO investments is one of the primary differences between all of CMP315, 375 and its WACM, and the pre-CMP353 baseline.

Due to a lower number of primary new-build projects in the 10 years prior to the start of RIIO-ET2.and the relatively high cost of these in comparison to the projects in previous periods, due to substantial supra-inflationary increases in labour and materials costs across part of the 10 year calculation period, the EC would have increased significantly. Therefore, the ESO raised CMP353 to maintain the locational signal at the start of the RIIO-2 period at the RIIO-1 value plus relevant inflation in each charging year until such time as the effect of any change in the locational signal can be better understood. Ofgem approved CMP353 on 2 December 2020 and this was implemented on 1 April 2021.

The CMP353 decision letter also asked the ESO to look at a broader review of the Expansion Constant. CMP375 has been raised to cover this. There is an existing related Modification, CMP315, that "seeks to review how the expansion constant is determined such that it best reflects the costs involved" and was raised on 16 April 2019. There is interaction between CMP315 and CMP375 but amalgamation under CUSC 8.19.3[2] has not currently been sought. Instead, they are progressing in parallel – with joint workgroup meetings. During discussions at the workgroup, the two proposers coalesced most of the calculation method for the two originals so that they are identical apart from the treatment of non-circuit elements.

For the avoidance of doubt, if neither CMP315 nor CMP375 were approved by Ofgem, the current levels of EC would continue (continuing to be uplifted by inflation year-on-year).

What is the solution?

Proposer's solution for CMP315 and CMP375

Category	CMP315 Original	CMP375 Original
Works Included	Extend the scope of works used in the calculation of the Expansion Constant to include: **New Circuits** - Construction of a new Circuit **Circuit Reinforcements** - Reusing existing towers but reinforcing conductor **Non-Circuit Reinforcements** - Replacement or enhancement of assets at Substations **Circuit Life Extensions** - Works to keep existing assets in use for longer than originally intended. Recalculate and	As per CMP315 but excludes **Non-Circuit Reinforcements** - Replacement or enhancement of assets at Substations.

[2] CUSC 8.19.3 *"Subject to Paragraphs 8.14.3 and 8.17A.4(b), the CUSC Modifications Panel may decide to amalgamate a CUSC Modification Proposal with one or more other CUSC Modification Proposals where the subject-matter of such CUSC Modification Proposals is sufficiently proximate to justify amalgamation on the grounds of efficiency and/or where such CUSC Modification Proposals are logically dependent on each other."*

	apply a Expansion Constant (EC) value (for each circuit type as per today) applicable from the Implementation Date based on the wider scope of works. **Civils Costs -** Civil costs associated with overhead towers or underground cables are included, based on specific project profiles as described in STCP14-1. Note that the WG asked for a change so that: at the moment, an expansion constant is effectively calculated for each asset class (132, 275 and 400 kV) separately for cables and lines; so, for 6 asset classes. However, it is only called the expansion constant for 400 kV overhead lines. The cost of the other 5 asset classes are converted to a cost ratio relative to this, e.g. 3, and called the expansion factor for that asset class. Within ESO's T&T model the expansion factor for an asset class is multiplied by the 400 kV line expansion constant to get an expansion constant for that asset class. The WG asked for a change so that there are 6 expansion constants, one per asset class. The legal text reflects this. The expansion constant was previous referred to as £/MWkm, which is not correct. It is now referred to as £/MW/km. £/(MWkm) would have been a less elegant but correct unit. Technically as it is amortised across years via the annuity factor calculation, it could be referred to as £/MW/km/year, but this approach was not taken.	
Weighting Methodology	MW km years based weighting – as of today, the EC is calculated as the length weighted average cost of all	As per CMP315

	relevant construction over the previous 10 years with the construction cost in each relevant year indexed by inflation to the current year. For annuitisation, split the cost of reinforcement that creates new capacity (Incremental MW) and new additional life (Incremental life).	
Data	Per asset class; 10 years historic data Use previous year's data and apply a "smoothing" factor (13% weighting factor applied per year* for new build and by implication 87% for the existing build cost, after adding inflation to last year's value for the same) to mitigate volatility and prevent sudden step changes. After a 5 year period, half of the value of the expansion constant for a given asset class will be driven by new data across that 5 year period, and half of it will be driven by the vaue preceding then. The workgroup called this a data half life of 5 years. It matches the current duration of a price control period, and is felt to reflect a reasonable compromise between indolence of the cost data (stability) and cost-reflectivity, bearing in mind that a marked potential step change in 2020 was regarded as undesirable by all participants and lead to the "freezing" that CMP353 represents. The smoothing is intended to prevent that situation arising again. ** It was also commented that 10 years historic data made up 100% of the cost in the approach prior to 2021, so50% of the value of the EC per asset class being driven by the*	As per CMP315

	last 5 years can be loosely compared with that aspect.	

Workgroup Consideration for CMP315 and CMP375

The Workgroup convened X times to discuss the issues, agree the scope of the proposed defect, devise potential solutions, and start to assess the proposal in terms of the Applicable CUSC Objectives.

Transport and Tariff Model Interpretation - General

Current TNUoS locational charges are based on an Incremental Cost-Related Pricing (ICRP) model of the long run marginal cost (LRMC) of the NETS. This is calculated by using the Transport and Tariff (T&T) model to work out the incremental flow on every circuit of the NETS caused by a change in generation and/or demand and multiplied by the annuitized value of the transmission infrastructure capital investment required to transport 1 MW over 1 km[3].

The T&T model uses different classes of transmission infrastructure (400kV, 275kV and 132kV and overhead line and underground cable) and takes as inputs annuitised costs per MW per km for each asset class. In the model these are characterised by the EC, the cost for 400kV overhead line, and then EFs for each asset class representing the ratio of the cost of 400kV overhead line to the other asset classes i.e. with the EF's being a multiplier of the EC. The EF for new build 400kV overhead line is 1.

This process is described in the CUSC at 14.15.4, where the T&T model is referred to as the DC Load Flow (DCLF) ICRP transport model:

"The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system".

Transport and Tariff Model Interpretation - General

The intention of both CMP315 and CMP375 is to retain the above methodology. There is a presentational difference as well as the changes below. Within ESO's T&T model the expansion factor for an asset class is multiplied by the 400 kV line expansion constant to get an expansion constant for that asset class. The WG asked for a change so that there are 6 expansion constants, one per asset class, as described in the legal text and as published to users in charging statements, rather than 1 expansion constant (for the 400 kV OHL asset class) and 5 expansion factors. This change on its own does not change tariffs one *iota*, it is presentational.

[3] CUSC 14.15.59

However, there are other changes proposed in 315 and 375 that alter the tariffs. The calculation of the cost annualized transmission investment should be expanded to reflect current practice that:

i. Some assets are being life extended[4]; and
ii. Some assets are having their capability enhanced (for example reconductoring overhead lines with higher capacity conductor).
iii. The NETS consists of more than just circuits.

The purpose of the EC (and EF) is to convert the distance (km) figure determined by the T&T model into a cost. The EC and EF are previously (prior to CMP353) calculated using standardised costs from the latest 10 years of volumes for new circuit (overhead line and cable) build. There are differences of opinion within the Workgroup whether the incremental nature of ICRP relates to the incremental transportation of energy on the NETS or the incremental expansion of the NETS to transport energy. The 1992 Transmission Use of System Charges Review (page 15) states:

"The cost of capacity per MW/km represents the annual cost of building and maintaining capacity to transport one MW of power one kilometre between points on the NETS. This incremental cost comprises two components: a capital cost and an operating cost. The capital cost is the cost of building (or having built) one MW/km of transmission capacity converted to an annual charge. The operating cost component covers the cost of repair and maintenance of capital equipment plus administration costs. The basis of the capital cost component is the current average cost at replacement value of the present system."

However, there is a difference of opinion as to how the value of the EC is reflected in the T&T Model and importantly the different interpretation won't affect how the T&T model works but will affect what data is input and what the T&T model's output is representing. Figure 1 below sets out this difference.

Figure 1

Transport and Tariff Model Interpretation - CMP315 Original	Transport and Tariff Model Interpretation - CMP375 Original (and all proposed CMP375 alternatives and/or WACMs)
The purpose of the EC (and EF) is to convert the distance (km) figure determined by the T&T model into a cost. EC/EF calculation reflects the cost of the whole NETS (i.e. a replacement value) which includes all assets and works undertaken on the NETS See Annex 3 to support this view.	The purpose of the EC (and EF) is to convert the distance (km) figure determined by the T&T model into a cost. EC/EF calculation reflects the growth in the NETS

Transport and Tariff Model Interpretation – Other Workgroup Member View (not taken forward in any of the proposed solutions)

[4] This could mean the depreciation period in the Expansion Constant could differ from the regulatory settlement

Another Workgroup Member's view was that the TNUoS model need to change to better reflect the reality of developments in the NETS where incremental cost is no longer based on the installation of 400kV circuits. This alternate approach also challenges traditional thinking where sunk costs made up of the historic build of the 400kV network are the core of the marginal cost calculation used to determine the EC. This approach seeks to establish the forward-looking marginal cost over a realistic 5–10-year time horizon that is consistent with the RIIO-T2 business plans.

The vast bulk of the 400kV NETS is sunk cost and it is unlikely to be decommissioned or indeed expanded with new 400kV circuits, The Workgroup Member argued that to continue to include it in a forward-looking charge could be viewed as sub-optimal. The proposed alternate approach would replace the cost of new build 400kV in the EC with a representative "basket" of techniques and technologies that are expected to be used over the next 5-10 years. The ESO would determine the makeup of this basket that would likely be based on planned and future development drawn from the RIIO T2 business plan for each TO. These would likely include:

a) New circuit build (existing methodology)
b) Circuit replacement/refurbishment
c) New non-circuit build e.g. substations
d) Non-circuit reinforcement e.g. transformers
e) 'Smart' reinforcement option e.g. intertrips and Active Network Management
f) Life extension options
g) Non-thermal solution options e.g. circuit breaker replacement
h) Re-using existing connection points as traditional carbon-based generation closes

Each would be appropriately weighted to reflect the MW capacity they are likely to bring within each Transmission Owner region.

There are various ways that this change could be implemented in the TNUoS model. The Workgroup Member presented one solution would be to broaden the definition of the EC in CUSC 14.15.59 as follows (the changes are shown in red text):

> *14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of a representative basket of technologies and techniques that are used to accommodate changes in circuit use at 400kV ~~of 400kV overhead line~~, including an estimate of the cost of capital, to provide for future system expansion.*

The relative cost at other voltages and for cable circuits would be relative to this new definition.

The ESO is already required in the CUSC[5] to derive this parameter using information from the onshore Transmission Owners but, under this approach, this will be expanded to

[5] CUSC 14.15.61 – *"The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement."*

include all of the technologies and techniques set out in (a)-(h) including re-use of existing connection points following the closure of the carbon-based generation where the marginal cost is close to zero.

1) Works Included

What else could be included in the future EC Calculation?

At the start of the Workgroup process, the ESO Workgroup Member shared a list of potential works that are currently excluded in the EC calculation but could potentially be included to provide a more accurate calculation and this is represented by Figure 2 below:

Figure 2

Type	Description	Examples	Current EC Methodology?	Creates MW capacity	Includes km
New circuit build	Construction of a new circuit	Brand New 400kV circuit	Y	Y	Y
Circuit Reinforcement	Reusing existing towers but reinforcing conductor	Reconductoring, hot wiring, circuit rebuild	N	Y	Y
New non-circuit build	Build of new assets not linked to a circuit	New substations and associated assets	N	Y	N
Substation reinforcement	Replacement or enhancement of assets at substations	Transformer/CB replacement, forced cooling	N	Y	N
'SMART' reinforcement	Works to allow increased network utilisation.	Intertrips, ANM	N	N	N
Life extension	Works to keep existing assets in use for longer than originally intended	Transformer/asset refurbishments	N	N	Y
Non-thermal solutions	Reinforcement to solve a non-thermal constraint (e.g. fault level) allowing access to MW capacity as a secondary benefit	Circuit Breaker replacement, voltage pathfinders	N	N	N

A Workgroup Member disagreed that 'SMART' reinforcement does not provide MW Capacity and noted that Scottish Power Energy Networks are delivering a NETS reinforcement[6] that provides new capacity via 'SMART' reinforcement in lieu of network build, wherein connected users will be compensated for their network access being below design standards. However, the Proposer of CMP375 noted that this is still not physically firm capacity and therefore, in their opinion, does not create MW capacity for the purpose of the EC calculation. The Workgroup noted that 'SMART' reinforcement in lieu of network build could become more prevalent in the future, however, is not included as part of the original proposals for CMP315 and CMP375.

The Proposer of CMP375 then presented their assessment of each option using the following criteria (Figure 3) with those in the Red category needing the most change:

Figure 3

Subject Area	Red	Amber	Green
Methodology (i.e. do we know how this would work and how it interacts	Would need to be developed in full.	Current methodologies would need to be substantially changed or	Minimal or no change from current methodologies with

[6] For further detail on this NETS reinforcement, please refer to TORI Quarterly Update report, which has 1 summary page on SPT-RI-284: Transmission Connections - SP Energy Networks

with the wider TNUoS methodology?)		interactions with other parts of the TNUoS methodology would need to be explored.	limited interactions with other parts of the TNUoS methodology.
System/Data (i.e. can our existing tools cope with the new methodology and do we have the needed data?)	Significant new tools would need to be created	Supplementary tools to be created or significant data changes needed	Minor changes to underlying data within existing tools
Timescale (i.e. when can we do it for?)	April 2025+	April 2024	April 2023

The results of the Proposer of CMP375's analysis is represented by Figure 4 below:

Figure 4

Reinforcement Type	Possible Implementation approach	Methodology	System/Data	Timescale
(A) New circuit build	1. No change	No changes needed from today		
	2. Circuit Specific calculation	Applies current methodology	Green for new circuits Amber for reinforcement	Green for new circuits Amber for reinforcement
	3. Boundary constraint	To be fully developed	New systems/processes needed	Time needed for development
(B) Circuit Reinforcement	1. Treat the same as (A) i.e. included in EF basket together with (A)	Same as chosen option for (A) – EC and EFs are still single numbers.		
	2. New 'Reinforcement Factor' for a specific circuit	Methodologies to be revised	Data required from TO, may be insufficient projects	Development and data collection
(C) New non-circuit build & (D) Non-circuit reinforcement i.e. how you reflect substation costs into the EC/EF calculation	1. Allocate assets across existing circuits, and include in EF basket together with (A)	TBC how assets allocated, although a Workgroup Member believes that this should be amber as the LCP approach has shown that this can be done without entire new methodology nor significant tooling	Significant number of data changes	Data required from TO and inputting in to T&T model
	2. Create a new 'proxy circuit' with EF separate to (A)	Current methodology used but interactions to be considered.	Significant number of new circuits to be added	Data required from TO and inputting in to T&T model
	3. No change	No changes needed from today		

(E) 'SMART' reinforcement	1. No change	No changes needed from today		
	2. Treat the same as (C) and (D)	Interactions across TNUoS	Same as chosen option for (C) and (D)	
	3. New 'Reinforcement Factor'	Methodologies to be revised and Interactions across TNUoS	Data required from TO, may be insufficient projects	Development and data collection
(F) Life extension	1. No change	No changes needed from today		
	2. Treat the same as (A) i.e. included in EF basket together with (A)	Clarifications in methodology	Data required from TO	Data required from TO

Other key points were:

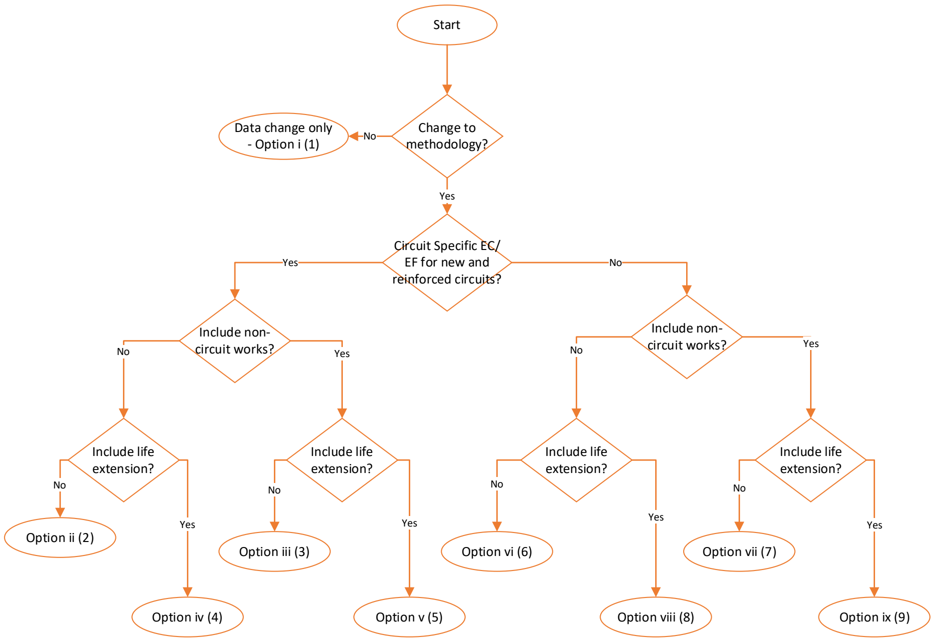
- Although Intertrips could theoretically be covered in the EC, 'SMART' reinforcement has too many interactions across TNUoS methodology (e.g. Security factor, Sharing Factor, Design variation v s operational intertripping) that need to be considered to progress quickly.; and
- For the Non-Transmission Owner led solutions, the costs of these projects will be covered by BSUoS and so not impact TNUoS and therefore including them would be double counting.

Based on excluding 'SMART' reinforcement and Non-Transmission Owner led solutions, the Proposer then presented 9 resulting options for the Workgroup to consider. These options arise from 3 broad key components;

- Should there be Circuit Specific Expansion Constants/Expansion Factors?:
- Should non-circuit works be included?; and
- Should life extensions (Works to keep existing assets in use for longer than originally intended) be included?

The following flow chart (represented by Figure 5) shows the 9 resulting options diagrammatically.

Figure 5



The Workgroup ruled out options which contemplated a Circuit Specific Expansion Factor for reasons of practicality and materiality, as you would need a number of years before there is enough data to make a significant difference to the calculation.

Post Workgroup Consultation, the Proposers of CMP315 and CMP375 concluded which works should be included and noted that the treatment of substations is the only difference between CMP315 and CMP375 (Original and CMP375 proposed alternatives and/or WACMs). Some Workgroup Members (including the Proposer of CMP315) argued that a breakdown of individual elements within substations could arguably provide further accuracy/granularity and the Proposer of CMP315 set out their thinking on how substations would be charged – see Annex 4 . However, other Workgroup Members (including the Proposer of CMP375) believed adding such granularity would add complexity and believed it would be very difficult to agree a consistent approach.

ESO's impact assessment on CMP315 has been based on the approach to "smear" substation costs over the lengths of associated circuits around the substation. Instead of obtaining some detailed site-specific information from TOs e.g. which substation had interbus transformers installed/replaced, and the length of circuits around the substation, the analysis was based on generic assumption of circuit lengths on average for that voltage level, derived from the TNUoS model, and applied the generic "average" circuit lengths accordingly on the non-circuit assets.

The final position on which works are included is set out below and all the proposed alternatives and/or WACMs for CMP375 are in line with CMP375 Original on this matter.

Category	CMP315 Original	CMP375 Original

Works Included	Extend the scope of works used in the calculation of the Expansion Constant to include: **New Circuits** - Construction of a new Circuit **Circuit Reinforcements** - Reusing existing towers but reinforcing conductor **Non-Circuit Reinforcements** - Replacement or enhancement of assets at Substations **Circuit Life Extensions** - Works to keep existing assets in use for longer than originally intended. Recalculate and apply a Expansion Constant (EC) or Expansion Factor (EF) value (for each circuit type as per today) applicable from the Implementation Date based on the wider scope of works. **Civils Costs -** Civil costs associated with overhead towers or underground cables are included, based on generic project profiles as described in STCP14-1 (e.g. assuming no motorway crossing etc) – note that this is the current treatment of civils costs.	As per CMP315 but excludes **Non-Circuit Reinforcements** - Replacement or enhancement of assets at Substations.

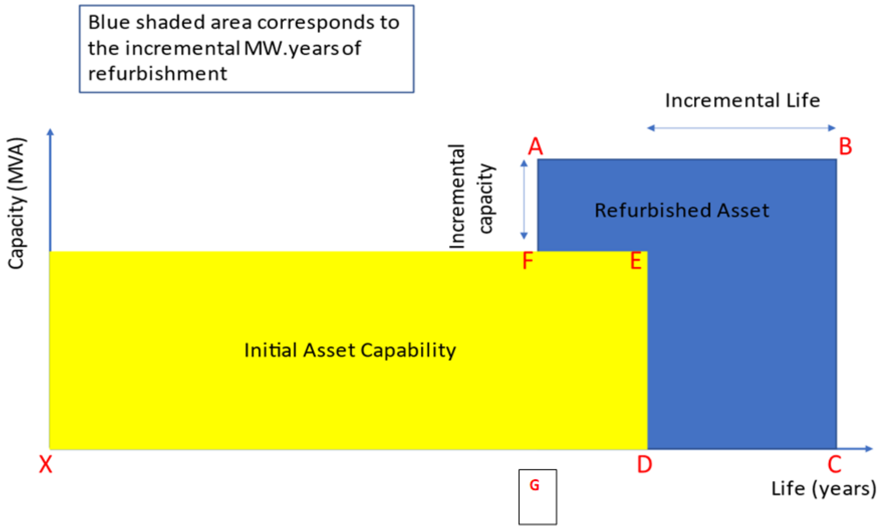
2) **Weighting Methodology**

MW km years based weighting – as of today, the EC is calculated as the length weighted average cost of all relevant construction over the previous 10 years with the construction cost in each relevant year indexed by inflation to the current year.

For annuitisation, split the cost of reinforcement that creates new capacity (Incremental MW) and new additional life (Incremental life).

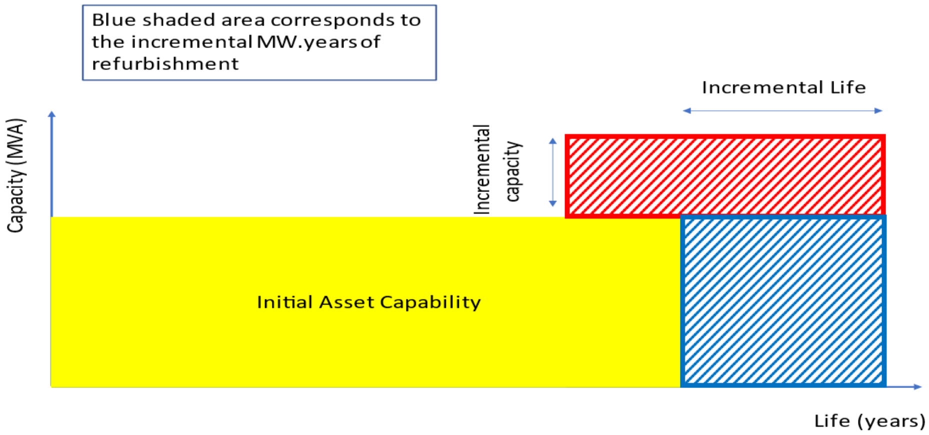
The following (figure 6) sets out how this calculation would be run:

Figure 6



1. Calculate the MW/years of the blue shape so you can do the MW/years/km weighting at the end.
2. Calculate the cost per MW/km of each upgrade based on the incremental MW (A to F on the diagram)
3. Annuitise this over the new life of the project (A to B on the diagram).
4. Weight all the £/MWkm by their MW/years/km calculated in step 1 above.
5. Cut the blue shape into constituent rectangles ((AB*AF) and (ED*DC)) and then apportion the cost of the upgrade across them based on their MW years.
6. Then calculate the MW/km based on the relevant MWs for the rectangle and annuitise based on the relevant years for the rectangle. This splits the cost of reinforcement that creates new capacity (Incremental MW) and new additional life (Incremental life) as per Figure 7 below. The CMP315 and CMP375 Original did not initially split the cost of reinforcement that creates new capacity (Incremental MW) and new additional life (Incremental life) as unclear how e.g. if you reconductor a circuit and both extend its life and increase its capacity, how do you allocate the costs between the two elements). However, both the Proposers of CMP315 and CMP375 Original ultimately agreed to apply the split following input from a Workgroup Member on how to perform the maths correctly to take account of both added years and added capacity in these cases. This method of splitting the two elements was more mathematically robust.
7. In the very rare case where a reinforcement or reconductoring project added neither capacity nor added life in years, it was decided to ignore the project for the purpose of expansion constant calculations, to avoid a divide by zero error problem, and because such a project is not really a reinforcement and is not actually adding any MWkm's at all.

Figure 7



8. Finally, average based on MW/years/km

The full breakdown of how the calculation for the CMP315 and CMP375 Original will be run is set out in Annex 11.

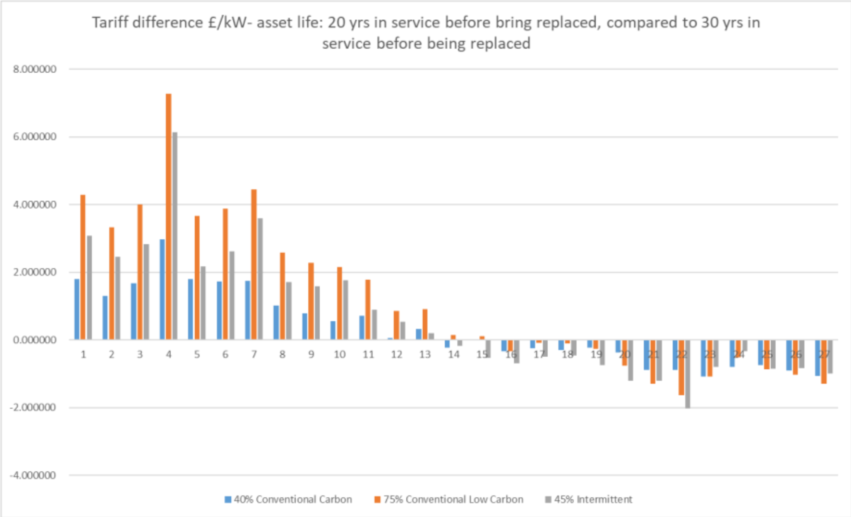
Defaulting Rule for Asset Life Extensions

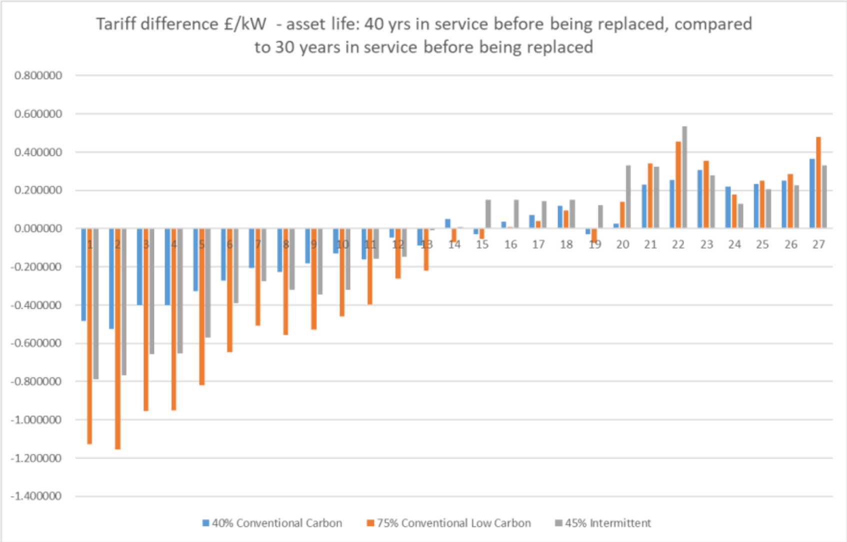
Once the solutions were clarified, there was a clear steer from the Workgroup that they need to see how the tariffs would be impacted by these solutions, to act as a sense check, before the Workgroup phase could be concluded.

During this exercise, the ESO Workgroup Member noted that asset life data before and after an investment in an existing asset is not always available so applied a default 45 years of remaining life after an investment is made in an existing asset, where the TO was not able to estimate a life, due to a mixture of components being embodied in the asset with different component lives. The default assumption for the remaining life of such existing assets immediately prior to the relevant investment, where the TO is unable to supply this data, is 0 years. These defaults combined, mean that 45 years of additional life is assumed in the case of such investments. This matches the typical life for price control purposes of a new investment. The Proposers of each of the three solutions at the time (CMP315 Original, CMP375 Original and CMP375 WACM1) confirmed they were comfortable with the above approach. A Workgroup Member noted that applying a default 45 years of remaining life after an investment is made in an existing asset, seems optimistic and could be a material change to the expansion constant/factors numbers, where the TO was not able to estimate a life. To help set out the materiality, the ESO Workgroup Member:

- confirmed that the instances where the TO was not able to estimate a life represent 30 % of the data they had received; and
- provided asset life sensitivity analysis based on using 15,30 or 45 as a default asset life. A summary of this is set out in Figure 8 below and the full analysis is also included in Annex 9.

Figure 8





A Workgroup Member asked if there was a typical age of existing key components that are needed to support the reconductor asset. However a Transmission Owner representative confirmed that (although they carry out inspections every 5 years to assess the remaining life and check current condition) that they do not have this data and it appears there is also no public data available either.

Some Workgroup Members also challenged the assumption that all the existing kit is brand new when reconductored. On this point, some Workgroup Members believed that years of remaining life after an investment is made in an existing asset is closer to 45 years than 0 years (but couldn't say what the exact number of years would be) as current practice is that Transmission Owners would focus on incremental maintenance i.e. maintaining parts of an asset (e.g. conductor) to extend the life of the asset itself (e.g. overhead line) rather than replacing the asset itself but ultimately the asset will need to be replaced. To illustrate, the analogy of the maintenance of a public road was used - each time you replace the pot holes would increase the life of the existing asset (in this case the road) but at some point it would be prudent/more cost effective to replace the road itself. A Workgroup Member argued that you could exclude such small incremental investment but difficult to justify what should and shouldn't be included and Workgroup overall agreed that it would be more prudent to agree a defaulting rule.

Another Workgroup Member asked whether the Proposers of CMP315 and CMP375 should consider excluding projects where there is no asset life available. However, the Proposers of CMP315 and CMP375 agreed that in this case, default rules would apply of 0 years remaining life prior to a reinforcement and 45 years afterwards - see above section on "Defaulting Rule for Asset Life Extensions". The issue doesn't arise with new circuit builds.

3) Data

10 years historic data

Both the CMP315 and CMP375 Originals proposing using 10 years of historic data as per current process.

Currently the data that is used for calculating the EC and EFs is provided by the Transmission Owners / Offshore Transmission Owners to the ESO at the start of each Price Control. Both CMP315 and CMP375 provide for additional data requirements on the Transmission Owners and these will need to be formalised within the STCP change PM0124.

ESO also receive data from the Transmission Owners / Offshore Transmission Owners for the purpose of producing the Network Options Assessment (NOA). The data that the ESO receives as part of NOA is listed in Appendix B of the NOA methodology and includes Transmission Owner proposed options and expected Costs. Currently this data is not used for calculating the EC and EFs but CMP375 WACM1 did propose using this data alongside historic data; however, as discussed later in this document, these 2 datasets are not directly comparable.

The Workgroup initially considered whether it is feasible to use non-Transmission Owner sources of data (EU TSOs, DNOs, commodity prices, manufacturer prices etc.) instead of Transmission Owner data but concluded it wasn't for the following reasons:

- Questions whether this was more accurate/reliable than the Transmission Owner's data
- Unclear if they need additional sources of non-Transmission Owner data as not clear on what data is missing and they haven't seen any actual data as yet to make an informed judgement.

The Workgroup also considered if there was any additional benefit of using a combination of historic and forward looking data. Although the CMP315 and CMP375 Originals propose using historical data (as now), CMP375 WACM1 did propose using NOA data alongside historic data.

The Proposer of CMP375 argued that the current approach of 10 years historic data is preferable as it's quicker from a Workgroup development perspective (as it is current process) and the ESO no longer have details of the projects/calculations prior to RIIO-T-1 (i.e. from the Transmission Price Control Review era of price controls).

The Workgroup discussed different time periods over which to collect cost and reinforcement data. Some Workgroup Members expressed that a longer period may mitigate problems of insufficient data. Some Workgroup Members expressed that nearer to real-time and even partially forward-looking data (e.g. approved expenditure) may better reflect the growth of NETS. Specifically, these conversations covered:

1. **Data from a different timeframe**. More historic data (over the current 10 years) could be used to ensure there remains sufficient data for the calculation; however, this creates a risk that more recent developments do not affect the calculation sufficiently. This is partly mitigated by point 3 below. The Transmission Owners have since confirmed that they only hold historic data (for the previous 10 years); and
2. **Forward looking data (or a combination of historic and forward looking data).** Historic data could be replaced by (or augmented with) forecast data so that it is more reflective of future NETS investment. The challenge is ensuring these forecasts are accurate and transparent to industry. CMP375 WACM1 proposed adding NOA data to complement the historic data but, as discussed later in this document, was thought not to be cost reflective as they are high level budget costs not presented consistently with usual EC cost input.

The following table sets out the pros and cons identified of historic vs forward looking data.

	Pros	Cons
Forward Looking Data	Reflective of current developments	Accuracy concerns as high level budget costs, includes reopeners. Not directly comparable with historic data so arguably not cost reflective It won't all get built – can be mitigated by only including those costs which have been recommended to 'Proceed' or which have been specified as 'HND essential' in the NOA.
Historic Data	How the current Expansion Constant is calculated Certainty of Data	Not necessarily reflective of costs you may incur today

		Not enough data available as based on incremental capacity at 400kV and a small dataset could lead to increased volatility
Mix of Forward Looking Data and Historic Data	More likely to have sufficient data	How do you ensure the forward looking data can be compared with the historic data

The Workgroup noted the challenges of Transmission Owner data

- The data is not necessarily split into the components required for the CMP315 and CMP375 solutions and therefore assumptions will need to be made; and
- There are differing interpretations across each Transmission Owner

Given these challenges, the ESO Workgroup Member initially proposed an alternative approach to consider, which essentially avoids the need for project data from Transmission Owners and smears the Transmission Owners' Maximum Allowed Revenue (total revenues recoverable via TNUoS) across each circuit component. However, this was discounted after Workgroup discussion as Maximum Allowed Revenue data also includes pensions and other quite material non-network-related costs. The ESO Workgroup Member then proposed an updated alternative approach based on the cost of the whole GB transmission system as a total Regulated Asset Value (RAV) rather than Maximum Allowed Revenue. It was noted that this approach would only calculate the Expansion Constant and the Expansion Factors would still be calculated using the current approach and this would still require data from the Transmission Owners, which some believed would undermine the benefit. Some of the Workgroup saw merits in this approach but noted this is a departure from the current methodology[7] and it was unclear what costs are included in the RAV. Given the Workgroup's concerns on robustness and that it is a significant departure from the current methodology, this option was not developed further

Up until recently the data provided under the STC by TOs was required to be estimated current costs of construction, with the historic 10 year aspect relating only to volume of type of works completed. The STC, specifically STCP14-1 and its appendices, which have been unchanged throughout RIIO ET1 and into ET2, make it very clear that actual historic cost data is not required from TOs. This meant that the TOs did not collect actual project data, in the form now required, nor retained so far back in time. The earliest data available of use is available from the start of RIIO ET1 and this historical data has already been provided to the ESO. For this reason historic data for more than ten years in duration can only be constructed going forwards in time.

Smoothing

The smoothing used under all the solutions is the same and entails applying an 87% or 0.87 weighting to the previous year's data in each asset class, and applying a 13% or 0.13 weighting to the new data calculated for that asset class. This is done every year, to avoid sudden step changes.

In the first year of implementation, under 315 and 375, it is 10 years of project cost data that are taken account of in calculating the new datum to be weighted at 13% for each

Commented [CH(4]: Need to explain how we arrived at 13% and 87£ and how that leads to 50%. Explain why. Action for Paul Mott

Commented [CH(5R4]: This is covered in the paragraph below

[7] Current methodology looks at cost of capital and debt but the RAV is an initial market value that is then refined by deducting for depreciation and inflating by CPIH

asset class. In the second and later years of implementation, under 315 and 375, it is 1 years of new project cost data that are taken account of in calculating the new datum to be weighted at 13% for each asset class.

Commented [PM(6]: Added on 31st July 2023

The 0.13 smoothing factor thus ensures that each new EC value for a given asset class is only given a weighting of 0.13, with a 0.87 weighting given to the previous year's EC value for that asset class. The choice of 0.13 for this parameter means that over 5 years, which is the same duration as a transmission price control period, half of the value of the EC for a given asset class is driven by new data calculated over the previous 5 years, and half of the value of the expansion constant for a given asset class is driven by data from prior to that timespan. This can be described as a 5 year "data half-life". The Proposers of all the solutions consider that this choice creates a fair balance between cost-reflectivity and stability, noting the general concern to a big step change in the EC value.

Under the baseline, 10 years historic data drives the value of the new expansion constant per asset class that is calculated ahead of each price control, so each year's data has a one tenth approximate weighting.

Commented [PM(7]: Added on 31st July 2023

For each asset class e.g. 400 kV twin, the ESO will calculate a value using the most recent year's new data from the Transmission Owners once a year. ESO will then inflate up the last year's £/MWkm figure for that class and weight in the new data at 13% and old data at 87%. A summary of the calculation is:

1. In year 1, gather 10 years of historic data for the purpose of calculating the EC at first implementation, inflating all project data costs across that span, individually, to the current year by TOPI (price control) inflation (so a project 10 years ago has 10 years' inflation added, and one from last year has 1 year's inflation added); and
2. The calculation after year 1 is, for CMP315 original and CMP375 original, performed each year using only the last year's data (inflated up by one year), applying the "smoothing" factor to mitigate volatility.

The below table (which can also be found in Annex 10) shows how the data is scaled and weighted through subsequent years. As each year passes, the oldest data is weighted less and less, reducing the impact it has on the overall tariff. One workgroup member stated that this improves cost reflectivity as it supports spreading the cost of large projects over a number of years, rather than feeling the impact in just one year. There was some discussion regarding the balance between cost reflectivity and the need for a sensible implementation plan to avoid a situation where a volatile costs are introduced. Without a sensible implementation plan (such as this smoothing factor), there could be a negative impact on tariffs overall, dis-incentivising investment and impacting end consumers.

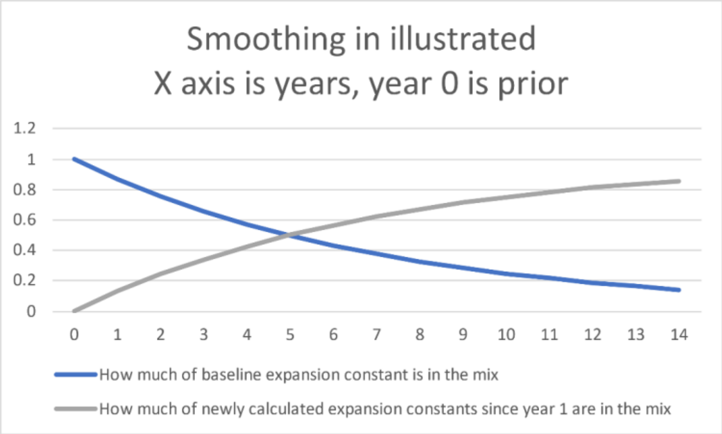
Figure 9

alpha	13%																		
	Current EC	2014 Data	2015 Data	2016 Data	2017 Data	2018 Data	2019 Data	2020 Data	2021 Data	2022 Data	2023 Data	2024 Data	2025 Data	2026 Data	2027 Data	2028 Data	2029 Data	2030 Data	Check
Year 1	87.0%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%								100.0%
Year 2	75.7%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	13.0%							100.0%
Year 3	65.9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	11.3%	13.0%						100.0%
Year 4	57.3%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	9.8%	11.3%	13.0%					100.0%
Year 5	49.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	8.6%	9.8%	11.3%	13.0%				100.0%
Year 6	43.4%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	7.4%	8.6%	9.8%	11.3%	13.0%			100.0%
Year 7	37.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	6.5%	7.4%	8.6%	9.8%	11.3%	13.0%		100.0%
Year 8	32.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	5.6%	6.5%	7.4%	8.6%	9.8%	11.3%	13.0%	100.0%

Using 10 years of history in step 1 is argued by the proposers of CMP315 and CMP375 Original to give us a 'solid' start number, as if we'd just had a 'normal' price review under the pre-CMP353 method, and then it is evolved year on year as per step 2. This 10years of historic data allows there to be an "average representation" data set to implement the new methodology. Geometric averaging weights each year differently, with most recent years having the highest weighting. In fact, no past year's data for a given asset class, once initially used as step 1, is ever entirely "forgotten" in CMP315 and CMP375 Original, but the averaging process scales down its influence by 0.87 for the calculation of the actual EC for that asset class, with each year that passes.

The Proposer of CMP375 originally favoured a smoothing factor of 20% as initially felt that 13% was potentially too sluggish. However, they found the rationale for 13%, put forward by the proposer of CMP315 at the September 2022 workgroup meeting, explained in the following paragraph, to be both cogent and compelling, and became convinced that due to the compound interest effect, 20% would have allowed the value to move relatively fast. Therefore, at that meeting they amended the smoothing used in CMP375 original to 13%, thus aligning with the CMP315 Original.

The 13% smoothing factor is applied so that each new expansion constant value for a given asset class is only given a weighting of 13%, with a 87% weighting given to the previous year's EC value for that asset class (the latter being first inflated up by one year's inflation). The choice of 13% for this parameter means chosen such that over 5 years, which is the same duration as a transmission price control period, half of the value of the EC for a given asset class is driven by new data calculated over the previous 5 years, and half of the value of the expansion constant for a given asset class is driven by data from prior to that timespan. This can be described as a 5 year "data half-life". It could also be argued that the 5 year data half life is comparable with the pre-CMP353 baseline where 100% of the value of the expansion constant depended on data for the 10 years prior to the start of a price control.



Justification for smoothing is:

- The costs which go into the EC are confidential and it is difficult for market participants to predict a future volatile EC/EF value. Also, the sharp and, to date, sustained increase in the cost of labour and key commodities relevant to transmission infrastructure that took place around 2018/2019, which was supra-inflationary (substantially exceeded general inflation), was not predictable. Smoothing helps with this volatility whilst allowing the values to change in a graduated, stabilised manner to reflect any changing costs going forwards.
- As the cost reflective signal is intended to promote locational decisions that lead to efficient network investment and also efficient use/re-use of existing network, the cost of the existing network should be factored in too. Additionally from a cost reflectivity perspective, smoothing helps to prevent the cost of the network being distorted, should a relatively small number of unrepresentative costs happen to set the EC for a given asset class in a particular period, as the new calculations per year will only drive 13% of the value of the EC for that asset class.

The Workgroup discussed that there are 2 phases to the smoothing factor.

1) Implementation – aimed at introducing the new Expansion Constant methodology so as not to "shock" the market by reducing the impact of a large step change

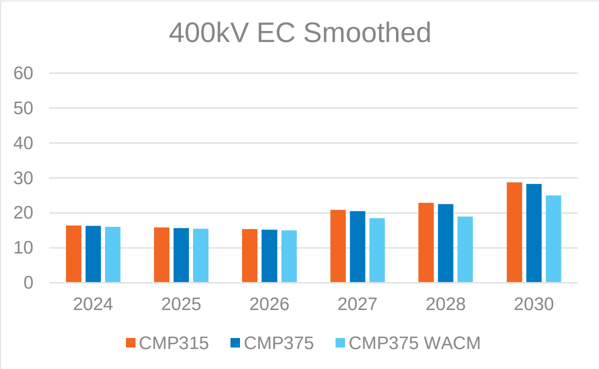
2) Transition – following implementation, a period of time whereby the new methodology is incrementally ramped up to absorb the change.

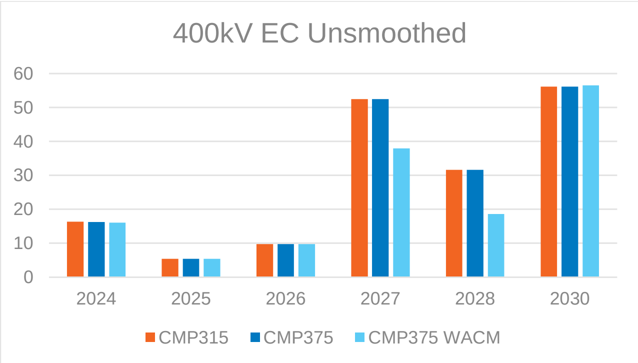
Smoothing factor analysis

The tables in figure 10 show the difference between ECs that are smoothed and not smoothed.

INSERT subsequent WG analysis

Figure 10





~~Explanation of 13% and 87%~~

Commented [CH(8]: Paul Mott and Nick Silito to draft

Commented [CH(9R8]: This is covered in a paragraph earlier.

The same smoothing factor methodology is used across both the original proposals for CMP315 and CMP375 to ensure continuity across both modifications. Whilst they are separate changes, there is a need to ensure there is standardisation and simplification of implementation.

Lane Clark and Peacock's (LCP) analysis

Ahead of the Workgroup Consultation, to show what the EC / EF values could look like, LCP (commissioned by one Workgroup Member) presented their analysis using project costs included from Scottish Power Energy Networks' RIIO-T2 published Business Plan. This analysis, which is described in detail in Annex 4, shows how expansion factors can be calculated using data from Transmission Owner's RIIO-T2 business plans and published surveys of new build circuits. The methodology uses costs estimates from planned reinforcements over the next price control period, along with details of the planned works. The analysis described requires datasets which are included within each Transmission Owner's RIIO-T2 business plans. Some Transmission Owners expressed reservations about their ability to share this data as, in their opinion, this is commercially sensitive and in any case should only be provided to the ESO via an STC request. Some Workgroup members have also approached Ofgem, who have the ability under Transmission Licence to request such data; however there is no route for Ofgem to disseminate any further. Some Workgroup members asked the ESO for support in resolving this issue and whether or not they could engage with LCP directly to use data obtained by the ESO to progress this solution (only sharing the outcomes with wider industry). The ESO Workgroup Member does not believe they could use LCP as this could leave them open to legal challenge and believe any consultancy support would provide more consumer value to the TNUoS Taskforces rather than CMP315/375 in isolation.

This analysis demonstrates that it is possible to calculate an EC and a new set of and EFs based on existing data sets which capture most of the reinforcement types required.

Using this data, LCP has developed a methodology for calculating the cost in £/MW-km terms for most of the reinforcement types covered, including circuit reinforcement and replacement, new non-circuit build and non-circuit reinforcement. This data is sourced from the RIIO-T2 engineering justification papers. Within this work, LCP have developed a methodology for calculating the MW-km contribution of non-circuit build based on the average network capacity enabled by the reinforcement.

To calculate ECs per asset class using these reinforcement costs, LCP have calculated the volume-weighted average cost of reinforcement using the volumes of each type of reinforcement planned for the upcoming price control period. This data is sourced from the RIIO-T2 Business Plan Data Tables.

EFs are no longer calculated relative to the EC under baseline EC, EC is the cost of new build 400kV Overhead Line (OHL). Instead, there is now an EC per asset class. However, as the expansion constants now includes other reinforcement types, the EC for each asset class lowered by that effect alone, ceteris paribus.

The table shows example EFs if all reinforcement types were included, based on the data made available by Scottish Power Energy Networks. Additional data from other Transmission Owners would enhance this analysis and may produce different EFs, particularly in cases where they are set by one or two reinforcement projects. To do this, some Workgroup Members asked the other Transmission Owners to consider passing information from their business plans directly to the ESO solely for the purpose of updating this analysis, however this issue has not been progressed, as explained in the previous section. WACM2 does require that the TOs give business plan data, and annual updates to the same, to the ESO, insofar as they give circuit length data for new build vs for reinforcements and reconductoring, by asset class. No other aspect of them is relevant for WACM2's "basket of works" concept.

	New approach		Current approach	
Voltage	OHL expansion factor	Cable expansion factor	OHL expansion factor	Cable expansion factor
400kV	0.47	5.75	1.00	10.20
275kV	0.81	3.31	1.20	11.45
132kV	1.29	5.05	2.87	22.58

Workgroup Consultation Summary

The Workgroup held their Workgroup Consultation between 14 April 2022 and 17 May 2022 and received 28 non-confidential responses and 1 confidential response. A summary of each of the non-confidential responses and the full non-confidential responses can be found in Annexes 6 and 7 respectively. In summary:

- **Overall** there was support for each of the Modifications (though less for CMP315 as CMP375 was felt to be more cost reflective as looked at the incremental cost). There was also support for the approach proposed by LCP (which became CMP375 WACM1) as more forward-looking, cost signal data better aligns with the period for which people are charged and there appear to be less data requirements (although a shortfall of this data identified was what happens with reopeners).

- **On Implementation**, although some urged the need for a 1 April 2023 date with a sensitivity study of possible new tariffs at the earliest reasonable opportunity (as unlikely to be approved for draft tariffs), there were others who suggested later implementation dates predominantly to not rush given the materiality and provide market with sufficient notice to understand and prepare. Note that earliest Implementation Date is now 1 April 2024 but that appears unlikely based on current timeline and the likelihood of Ofgem undertaking an impact assessment before making a decision. 1 April 2025 was discussed at the 22nd June Workgroup meeting bearing in mind the likelihood mentioned by Ofgem of needing a 3 month impact assessment (with consultation) once the FMR has been remitted to Ofgem following the CUSC Panel's vote.

- **On data to be used to calculate the Expansion Constant** there was a mix of views as to whether or not to use historical or forward looking (using the Transmission Owners' Business Plan data) or indeed a mix of the two where e.g. there is a lack of forward-looking data.

- **With regards to whether non-circuit build should be allocated to existing circuits rather than proxy circuits**, there was a mix of views. Those who supported proxy circuits noted it was simpler and more cost reflective and those who supported Existing Circuits argued that the proxy circuit approach sharpens the locational signal disproportionately.

Workgroup Alternatives

Post Workgroup Consultation, a Workgroup Member raised an alternative to the CMP375 Original, which after extensive Workgroup discussion would differ from the CMP375 Original in the following way:

Alternative Solution(s)	Details
CMP375 Proposed Alternative 1 - became CMP375 WACM1	**Works Included** – as per CMP375 Original. **Weighting Methodology –** MW km to weight the costs of reinforcements as per CMP375 Original. However, when calculating the representative basket of works, propose to use km weightings as this data is already produced as part of Transmission Owners' regulatory reporting. *If it were possible to obtain MW-km from the Transmission Owners' in the same format, then would consider using these in future.*

	Data - Use forward looking data (where available) to calculate Expansion Constant. Use a mix of ESO's Network Options Assessment (NOA) works (those works which have been recommended to 'Proceed' or which have been specified as 'HND essential'*) for cost and volume data for planned works at 400kV for OHL and Cable works and data from Transmission Operators' price control business plans to provides volumes of proposed works across all voltage levels and estimated costs of proposed works. **Whether or not it is appropriate to include all works is not possible to judge without access to the data* Continues to use 10 years of historic data to calculate Expansion Factors. Proposes to use Transmission Owner Approved Business Plan data to estimate the proportion of newbuild costs (additions) and refurbishment costs (replacements) which should be considered when calculating the representative basket of works.

The proposer of this alternative, which became WACM1, argued that using forward looking data, better represented the cost of expansion to the NETS and increasing the number of data points would be beneficial. However, there were some concerns about how directly comparable historic data and forward-looking data would be especially as the forward looking data is at a higher level and not split out as the historic data can be.

Also, the proposer of this alternative, only seeks to include a subset of ESO's Network Options Assessment (NOA) works – specifically those works which have been recommended to 'Proceed' or which have been specified as 'HND essential' as the others are either too uncertain and/or too far out into the future. Using NOA7, the ESO Workgroup Member in their analysis included those projects with "Proceed" or "HND essential", which was 82 in total. They then removed options with any of the following;

- Works purely for voltage (MSCs and Reactors – i.e. no MW capacity change)
- Power Flow Control Devices (i.e. no MW capacity change)
- Subsea links (circuit specific EF for these circuits)
- Works with optimal delivery date beyond 2033 (i.e. >10 years' time)
- Insufficient data available (e.g. no ratings provided)

This led to the removal of 33 projects, leaving 49 projects remaining. On these 49 projects, the following assumptions were made:

- Where possible, used pre-fault ratings instead of post-fault (i.e. representing intact network).
- Where 'no change' indicated, then current Transport & Tariff model values used.
    - Where voltage upgrades occur, included in the new voltage.

Figure 11~~9~~ below shows the output of this.

Figure ~~9~~11

NOA Data Summary

Of the remaining 49 projects;

Work Type (count)	275kV	400kV
Cable	0	3
Circuit + substation	0	1
New substation	0	1
New substation + OHL	0	7
New substation + OHL + Cable	0	1
OHL	1	29
OHL + Cable	0	3
OHL + SGTs	0	2
OHL + Underground cable + Bay extension	0	1
Total	**1**	**48**

TO (count)	275kV	400kV
NGET	0	37
NGET & SPT	0	2
SPT	1	6
SHETL	0	4
Total	**1**	**48**

	Average	Total
Rating (MW)	2590	126,930
OHL Length (km)	56	2,193
Cable Length (km)	5.6	74
Cost (£m)	165	8,097

Cost change between NOA6 & NOA7	Count
N/A – New projects	13
± 5%	20
>5% reduction in costs	10
>5% increase in costs	6

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On 5 December 2022, the Workgroup voted as to whether or not the proposed Request for Alternative should become a Workgroup Alternative CUSC Modification (WACM). A majority of the Workgroup(11 out of 13 votes) did believe this request for Alternative may better facilitate the CUSC Objectives than the CMP375 Original so this became CMP375 WACM1 and the actual documentation is included in Annex 8.

With the principles agreed, the Workgroup confirmed, that they needed to see how the tariffs would be impacted by any of the solutions, to act as a sense check, before the Workgroup phase could be concluded. This tariff analysis is set out in Annex 10. The analysis for CMP375 WACM1 showed an Expansion Constant higher than that for the CMP315 or CMP375 Originals and this was largely due to the limitations of the NOA data. These limitations were:

- No 132kV and limited 275kV projects and given the low numbers of projects, an expensive project could lead to very high EC
- NOA data does not appear to exclude civils and planning costs, which should be excluded as otherwise it upwardly distorts the EC for the CMP375 WACM1. This is because the NOA data is an early cost indication, which appear to include contingency, and will be refined later..

The proposer of WACM1 proposed that, if the data excluding civils and planning costs is not available, a % cut could be applied based on historic civils and planning costs based on a public data source of how much of a Transmission project is comprised of these. However, no such public data source seems to exist and after further reflection that the NOA data in aggregate is not cost reflective as they are high level budget costs not presented consistently with usual EC cost input, the proposer of WACM1 decided not to proceed further with WACM1. Also, no Workgroup Member wished to become the new proposer of WACM1

Therefore, the proposer of WACM1 presented a new proposed alternative, which removed the forward-looking component of CMP375 WACM1 as data does not appear cost reflective and instead sought to extend the backwards looking component from the preceding 10 years to up to the preceding 30 years to expanding the time period of historic data, in line with investment horizon of new build generation projects. Although WACM1 no longer existed, it was decided for clarity to use a new WACM series reference number, hence WACM2.

Alternative Solution(s)	Details	Implementation Date
CMP375 WACM2	**Works Included** – as per CMP375 Original **Weighting Methodology** - Each EC or EF is calculated as a weighted average of cost data based on a set of expected works (a "basket of works"). The basket of expected works will be forward-looking and based on the future works set out in the Transmission Operators' price control business plans for each voltage level and circuit type. Introduction of MW km to weight the costs of reinforcements. When calculating the representative basket of works, propose to use km weightings as this data is already produced as part of Transmission Operators' regulatory reporting. **Data** - Up to 30 years of historic data but noting that only 10 years of historic data is available currently i.e the calculation after year 1 is performed each year using last year's data bundled up with the previous 10 years (without removing the project cost data for projects from the oldest year, Y-10, but rather increasing the overall historical data to 11 years in the second year, 12 years in the third year etc up to 30years in total when it shall then move to a rolling 30years of data) and apply a "smoothing" factor (0.13 smoothing factor for all years and not just for first year) to mitigate volatility.	1 April 2025

In the view of the proposer of this alternative, this will ensure enough data is gathered to accurately calculate the long-term relative costs of works at different voltage levels and prevents small amounts of data skewing the EC and is therefore arguably more cost reflective. Some Workgroup Members argued the contrary view that costs further back in time than 10 years are not cost reflective and do not reflect the current cost of adding a MW to the NETS. Also, it is likely that the data further back than 10 years will not be directly comparable as data in previous Price Control periods has been aggregated by asset class and was calculated only on the basis of the cost of primary new build, not using the costs of any cheaper reinforcement or reconductoring projects.

On 2 May 2023, the Workgroup voted as to whether or not the proposed Request for Alternative should become a Workgroup Alternative CUSC Modification (WACM). A majority of the Workgroup(10 out of 17 votes) did believe this request for Alternative may better facilitate the CUSC Objectives than the CMP375 Original so this became CMP375 WACM2 and the actual documentation is included in Annex 8.

However, the Transmission Owners have since indicated that they can't provide data further back than 10 years (which they have already provided to inform the numbers for CMP315 and CMP375 Original). Given this, the proposer of WACM2 asked if they could use previous EC/EFs values and the associated kms they represent for "historical data" and mix them with new data weighted by km (so for previous ECs/EFs it would be the entire network at each voltage level at the point in time those ECs/EFs were calculated). This would effectively mean that ESO would need to also process old EC data (which would only be new overhead line and new cable) per asset class calculated in the past based on a pre-CMP353 method when ECs were calculated only with new circuit costs, along with the new data calculated as a result of CMP375 Original (and CMP315 Original). The challenge would be how these two datasets are joined up and the weighting applied across these datasets. Also, a TO Workgroup Member confirmed they have no actual specific historic project data directly underpinning the historic ECs. After further reflection, the proposer of WACM2 decided in the interest of not delaying the process any further and given the lack of data, they will not seek to pursue this further and instead keep WACM2 as is as the principles are still valid on a looking-forward basis i.e. up to 30 years of historic data but noting that only 10 years of historic data is available.

WACM2 is a WACM to CMP375 and so does not use cost data for non-circuit elements such as quad boosters, switchgear or transformers.

Other Options discussed and not taken forward

Set Expansion Constant at Start of each Price Control but with smoothing (rolling average of most recent 3 price controls' raw values to incorporate some historic data too)) - Index linked

The Workgroup Member, who presented this, argued that 3 price controls strikes the balance between volatility and keeping an historic element. However, this was not pursued further as the same Workgroup Member was concerned with the amount of double counting of some years' investments which occurs and noted that the smoothing approach for the averaging of the Expansion Constant as developed by the CMP315 and CMP375 Originals also reflected the intent of their proposal. For instance, with 10 year historic data being used and a 6 year long price control there is a 4 year overlap between the raw values for adjacent price control periods. This means that over the 22 years that are used in the averaging over 3 price controls, 8 of them will be double counted, or around 36%, whereas 64% will only count once. The solution to this would be to use 6 years of historic data rather than 10. However, this then causes implications for implementation, which will occur half way through a price control, or periods when Ofgem may opt for different price control lengths.

Tariff Analysis

Now that the solutions are clear, there was a clear steer from the Workgroup that they need to see how the tariffs would be impacted by these solutions, to act as a sense check, before the Workgroup phase can be concluded. The analysis that ESO undertook is set out in Annex 9, and includes modelled effects on all parts of the demand TNUoS tariffs (thus fulfilling an aspect of the terms of reference; the floor on demand locational TNUoS tariffs at zero is included, as it is part of baseline and is not changed by these proposals), and in summary:

- The baseline is referred to as post-CMP353. Tariffs under CMP315, CMP375 and CMP375 WACM2 have been compared to the baseline (post-CMP353), and the results are shown in Annex 9.
- In addition, tariffs under the set of EC/EFs calculated by the ESO in 2020, prior to CMP353 being raised and approved, are also presented in Annex , known as pre-CMP353.

In terms of the north-south tariff polarity, pre-CMP353 > CMP315 > CMP375 > CMP375 WACM > post-CMP353 (baseline tariffs).

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Commented [CH(11R10]: Charts still outstanding.

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The floor on demand locational TNUoS tariffs at zero is included in the modelling, as it is part of baseline and is not changed by these proposals. As the "slope" or north-south tariff polarity is increased by these proposals (in the ranking order shown in the preceding paragraph), and as the floor causes the tariffs in the North of Scotland to be moved from a value of say -£33/kW to zero, the floor will have a greater effect for those options that exhibit the greatest north-south tariff polarity, and this shows up in the modelled tariff data.

[placeholder for charts]

Recital 63 of the EU Renewable Directive

One of the terms of reference asks the workgroup to discuss Recital 63 of the EU Renewable Directive https://energy.ec.europa.eu/topics/renewable-energy/renewable-energy-directive-targets-and-rules/renewable-energy-directive_en and consider if it has relevance. This directive was most recently updated in 2018.

https://lexparency.org/eu/32018L2001/PRE/ Recital 63 says "When favouring the development of the market for energy from renewable sources, it is necessary to take into account the positive impact on regional and local development opportunities, export prospects, social cohesion and employment opportunities, in particular as concerns SMEs and independent energy producers, including renewables self-consumers and renewable energy communities."

The workgroup looked at this and whilst it is no longer explicitly recited in the relevant UK Statutory Instrument, it does remain in force.~~.~~ However, [the workgroup concluded that it is no longer relevant with regards to this modification].

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Legal text

See Annex 10

What is the impact of this change?

Users who pay TNUoS charges

High EC values create a sharp locational signal and makes TNUoS charges higher in more expensive zones and lower in cheaper zones. Low EC values do the opposite.

Differences in revenue recovered due to the changing locational signal will cause changes to the value to be recovered through the Transmission Demand Residual (TDR) so the total value of TNUoS collected by the ESO is unchanged.

ESO

There will be changes to the T&T model inputs and ESO would need updated processes to include the additional data items in the EC calculation.

Transmission Owners and Offshore Transmission Owners

If this change is implemented, Transmission Owners will need to provide additional data to the ESO, potentially including additional data as part of their Business Plans.

This modification will not affect the overall cost recovery by the ESO on behalf of the Transmission Owners.

Proposer's assessment against Code Objectives

Proposers view of CMP315 and CMP375 Original against the CUSC Code Objectives

Proposer's assessment against CUSC Charging Objectives - CMP315	
Relevant Objective	**Identified impact**
(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	**Positive** More cost reflective charging helps facilitate a level playing field for competition.
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	**Positive** The purpose of this modification proposal is to refine the expansion constant so that it reflects the costs of all the assets used to construct the transmission system (rather than simply an idealised overhead line). This will improve the cost reflectivity

	of the locational element of the TNUoS charge allowing more cost reflective charging.
(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;	**Positive** More cost reflective charging provides a better match between allowed regulated revenues and actual costs so more properly takes account of developments to the transmission licences' business (c)
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Positive** Improving the cost reflectivity of charging also matches the objectives in Special Condition C10.
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Neutral**
*The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006	

Proposer's assessment against CUSC Charging Objectives - CMP375	
Relevant Objective	**Identified impact**
(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	**Positive** Clarity in the development of the EC and its likely direction of travel will provide more certainty to Users of their costs in future years.
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	**Positive** Amending the EC will allow the charging methodology to better account for developments in the costs of the transmission system.

(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;	**Positive** Amending the EC will allow the charging methodology to better account for developments in the costs of the transmission system.
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Neutral**
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** This modification will remove the temporary EC methodology and implement an enduring solution.
*The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006	

Workgroup Vote

The Workgroup met on XX MONTH 2023 to carry out their Workgroup Vote for CMP315 and CMP375. X Workgroup Members voted, and the full Workgroup vote can be found in Annex 12.

The Applicable CUSC charging objectives are:

a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);
c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;
d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and
e) To promote efficiency in the implementation and administration of the system charging methodology

*The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006

CMP315

The Workgroup concluded unanimously/by majority that the Original better facilitated the Applicable Objectives than the Baseline.

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Option	Number of voters that voted this option as better than the Baseline
Original	

Best Option – CMP315

Workgroup Member Company BEST Option? Which objective(s) does the change better facilitate? (if baseline not applicable)

Workgroup Member	Company	BEST Option?	Which objective(s) does the change better facilitate? (if baseline not applicable)

CMP375

The Workgroup concluded unanimously/by majority that the Original and WACM2 better facilitated the Applicable Objectives than the Baseline.

CMP375

Option	Number of voters that voted this option as better than the Baseline
Original	
WACM2	

Best Option – CMP375

Workgroup Member	Company	BEST Option?	Which objective(s) does the change better

			facilitate? (if baseline not applicable)

When will this change take place?

Implementation date
1 April 2025

Date decision required by
If needed in time for draft TNUoS tariffs for 2025/2026 to be published, then a decision on both the CUSC and STC Modifications would be needed by 1 September 2024 as there would need to be sufficient time for Transmission Owners to provide the data to ESO and ESO to update the T&T model and run the draft TNUoS tariffs.

If only needed in time for final TNUoS tariffs for 2025/2026 to be published, then a decision on both the CUSC and STC Modifications would be needed by 1 December 2024. This is possible under the current timeline even with Ofgem carrying out an impact assessment, which is understood to be likely needed. Some Workgroup Members expressed concerns with the lack of notice given that this is such a big change but noted that if the Workgroup's analysis was sufficiently detailed i.e. broke down the new EC/EFs per TNUoS zone, then this approach is possible.

Therefore, given current proposed timeline and the likelihood of an impact assessment being run before any decision is made, a 1 April 2025 Implementation Date would seem more appropriate.

Note that only one of CMP315 or CMP375 (or one of its WACMs) can be approved by Ofgem.

Implementation approach

Minimal changes made to the methodology, data and systems Transmission Owners to provide the data to ESO, which is line with that proposed for both CMP315 and CMP375.

Interactions

☐Grid Code	☐BSC	☒STC (PM0124)	☐SQSS

☐European Network Codes ☐ EBR Article 18 T&Cs[8] ☐Other modifications ☐Other

Acronyms, key terms and reference material

Acronym / key term	Meaning
BSC	Balancing and Settlement Code
CMP	CUSC Modification Proposal
CPI	Consumers Price Index
CUSC	Connection and Use of System Code
DNOs	Distribution Network Operators
EBR	Electricity Balancing Guideline
EC	Expansion Constant
EF	Expansion Factors
ESO	Electricity System Operator
EU	European Union
LRMC	Long Run Marginal Cost
NETS	National Electricity Transmission System
NOA	Network Options Assessment
RIIO	Revenue=Incentives+Innovation+Outputs
SRMC	Short Run Marginal Cost
STC	System Operator Transmission Owner Code
SQSS	Security and Quality of Supply Standards
T&Cs	Terms and Conditions
TO	Transmission Owner
TPCR	Transmission Price Control Review
TSO	Transmission System Operator

Reference material

- None

Annexes

Annex	Information
Annex 1	CMP315 and CMP375 Proposal forms
Annex 2	CMP315 and CMP375 Terms of reference
Annex 3	CMP315 Proposer's view of how Expansion Constant value should be represented in the Transport and Tariff Model
Annex 4	CMP315 Proposer's view of how substations should be calculated
Annex 5	Lane Clark and Peacock's (LCP) analysis
Annex 6	Summary of Workgroup Consultation Responses
Annex 7	Workgroup Consultation Responses
Annex 8	CMP375 Workgroup Alternative CUSC Modifications
Annex 9	Tariff and Sensitivity Analysis
Annex 10	Legal Text
Annex 11	Worked examples of how calculations will work

[8] If the modification has an impact on Article 18 T&Cs, it will need to follow the process set out in Article 18 of the Electricity Balancing Regulation (EBR – EU Regulation 2017/2195) – the main aspect of this is that the modification will need to be consulted on for 1 month in the Code Administrator Consultation phase. N.B. This will also satisfy the requirements of the NCER process.

Annex 12	Alternative and Workgroup Vote