|  |  |  |  |
| --- | --- | --- | --- |
| 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**    **Proposal Form**  16 April 2019 (CMP315); 17 June 2021 (CMP375)  **Workgroup Consultation**  14 April 2022 - 17 May 2022  **Workgroup Report**  20 July 2023  **Code Administrator Consultation**  01 August 2023 – 30 August 2023  **Draft Modification Report**  21 September 2023  **Final Modification Report**  11 October 2023  **Implementation**  01 April 2025  **1**  **2**  **3**  **4**  **5**  **6**  **7** | |
| **Have 5 minutes?** Read our [Executive summary](#_Executive_summary_1)  **Have 20 minutes?** Read the full [Workgroup](#_Why_change?) 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](mailto:nsillito@peakgen.com)  Phone: **07491434518**  CMP375 : Paul Mott  [Paul.mott1@nationalgrideso.com](mailto: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](https://www.nationalgrideso.com/document/182121/download), 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.  **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. The Proposer of CMP375 seeks to instead create ‘proxy circuits’ to capture substations in the Transport & Tariff (T&T) model. |
| 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  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)) to mitigate volatility  *\*Previous 5 years of data makes up 50% of cost (consistent with current methodology where 10 years historic data = 100% of cost) so 13% is based is on this* | As per CMP315 |

**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.

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.

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](https://www.nationalgrideso.com/document/179891/download) noted they expected the ESO to revisit the issue of rezoning alongside the development of any further change to the EC[[1]](#footnote-2). ESO current plan is to only raise rezoning Modifications once clarity reached on the CMP315 and CMP375 solutions.

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 impact table (figure XX) |
| d) Consider any interaction with demand TNUoS tariffs if floored at zero |  |
| e) Consider in terms of aligning with Recital 63 of EU Renewable Energy Directive (2009/28/EC) |  |
| f) Consider the distributional effect on Consumer tariffs |  |
| g) Implementation timeframes to be considered ahead of the TO RIIO price controls in 2021 |  |
| 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 - |
| i) Be mindful of, and consider, the SCR |  |
| 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](https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp353-stabilising) 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.

Due to a lower number of built 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, the EC would have increased significantly. Therefore, the ESO raised [CMP353](https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp353-stabilising) 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](https://www.nationalgrideso.com/document/182121/download) 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]](#footnote-3) has not currently been sought. Instead, they are progressing in parallel – with joint workgroup meetings.

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 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. The Proposer of CMP375 seeks to instead create ‘proxy circuits’ to capture substations in the Transport & Tariff (T&T) model. |
| 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  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)) to mitigate volatility  *\*Previous 5 years of data makes up 50% of cost (consistent with current methodology where 10 years historic data = 100% of cost) so 13% is based is on this* | As per CMP315 |

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]](#footnote-4).

The T&T model uses different classes of transmission infrastructure (400kV, 275kV and 132kV and overhead line and underground cable) and has a cost per MWkm 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. However, the calculation of the cost annualized transmission investment should be expanded to reflect current practice that:

1. Some assets are being life extended[[4]](#footnote-5); and
2. Some assets are having their capability enhanced (for example reconductoring overhead lines with higher capacity conductor).
3. 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](https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp353-stabilising)) 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)**

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:

1. a) New circuit build (existing methodology)
2. b) Circuit replacement/refurbishment
3. c) New non-circuit build e.g. substations
4. d) Non-circuit reinforcement e.g. transformers
5. e) ‘Smart’ reinforcement option e.g. intertrips and Active Network Management
6. f) Life extension options
7. 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.

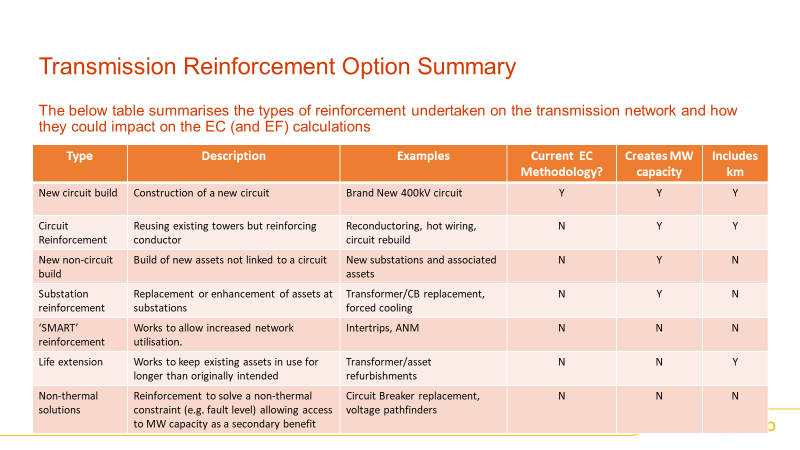
The ESO is already required in the CUSC[[5]](#footnote-6) to derive this parameter using information from the onshore Transmission Owners but, under this approach, this will be expanded to include all of the technologies and techniques set out in (a)-(h) including re-use of existing connection points 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**



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]](#footnote-7) 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 with the wider TNUoS methodology?) | Would need to be developed in full. | Current methodologies would need to be substantially changed or interactions with other parts of the TNUoS methodology would need to be explored. | Minimal or no change from current methodologies with 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 | | | | | | |
| 1. Circuit Specific calculation | Applies current methodology | Green for new circuits | | Amber for reinforcement | Green for new circuits | | Amber for reinforcement |
| 1. 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. | | | | | | |
| 1. 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 | | |
| 1. 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 | | |
| 1. No change | No changes needed from today | | | | | | |
| (E) ‘SMART’ reinforcement | 1. No change | No changes needed from today | | | | | | |
| 1. Treat the same as (C) and (D) | Interactions across TNUoS | Same as chosen option for (C) and (D) | | | | | |
| 1. 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 | | | | | | |
|  | 1. 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 Intertripscould 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). ESO’s current analysis represents substations as 1km of circuit. 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.

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. The Proposer of CMP375 seeks to instead create ‘proxy circuits’ to capture substations in the Transport & Tariff (T&T) model. |

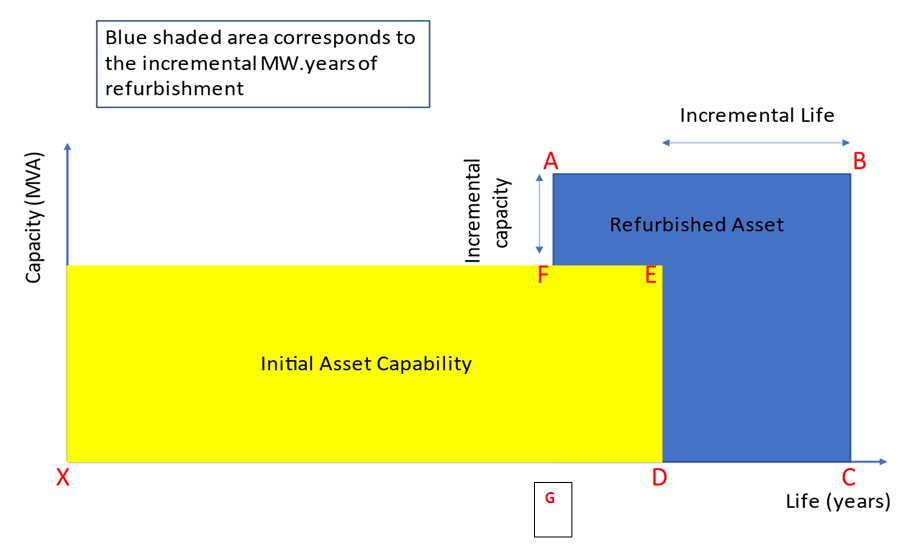
2) **Weighting Methodology**

**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).**

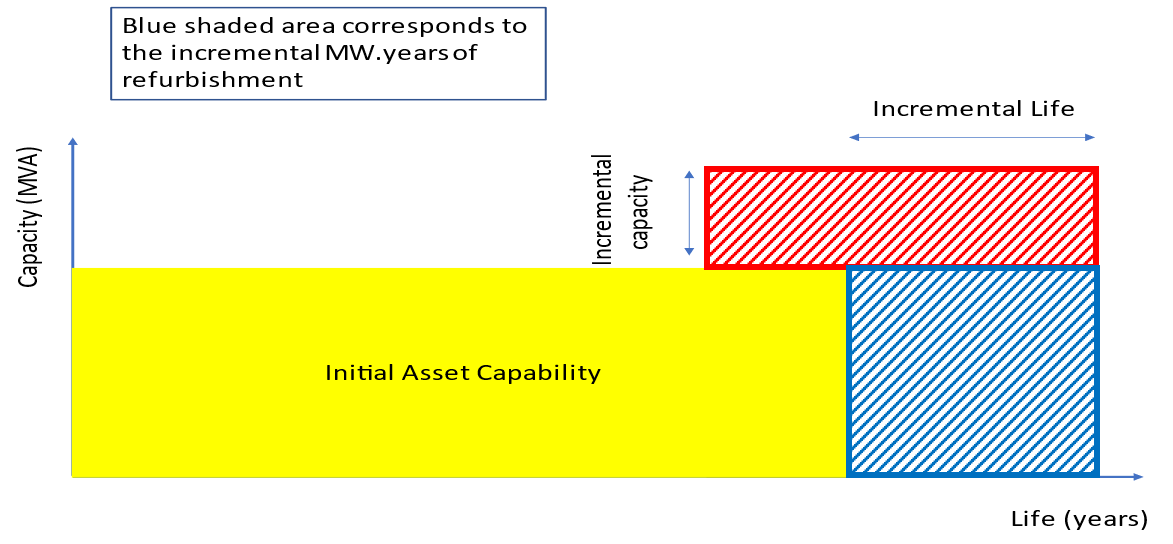
The following (figure 6) sets out how this calculation would be run:

**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.

**Figure 7**



1. 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.

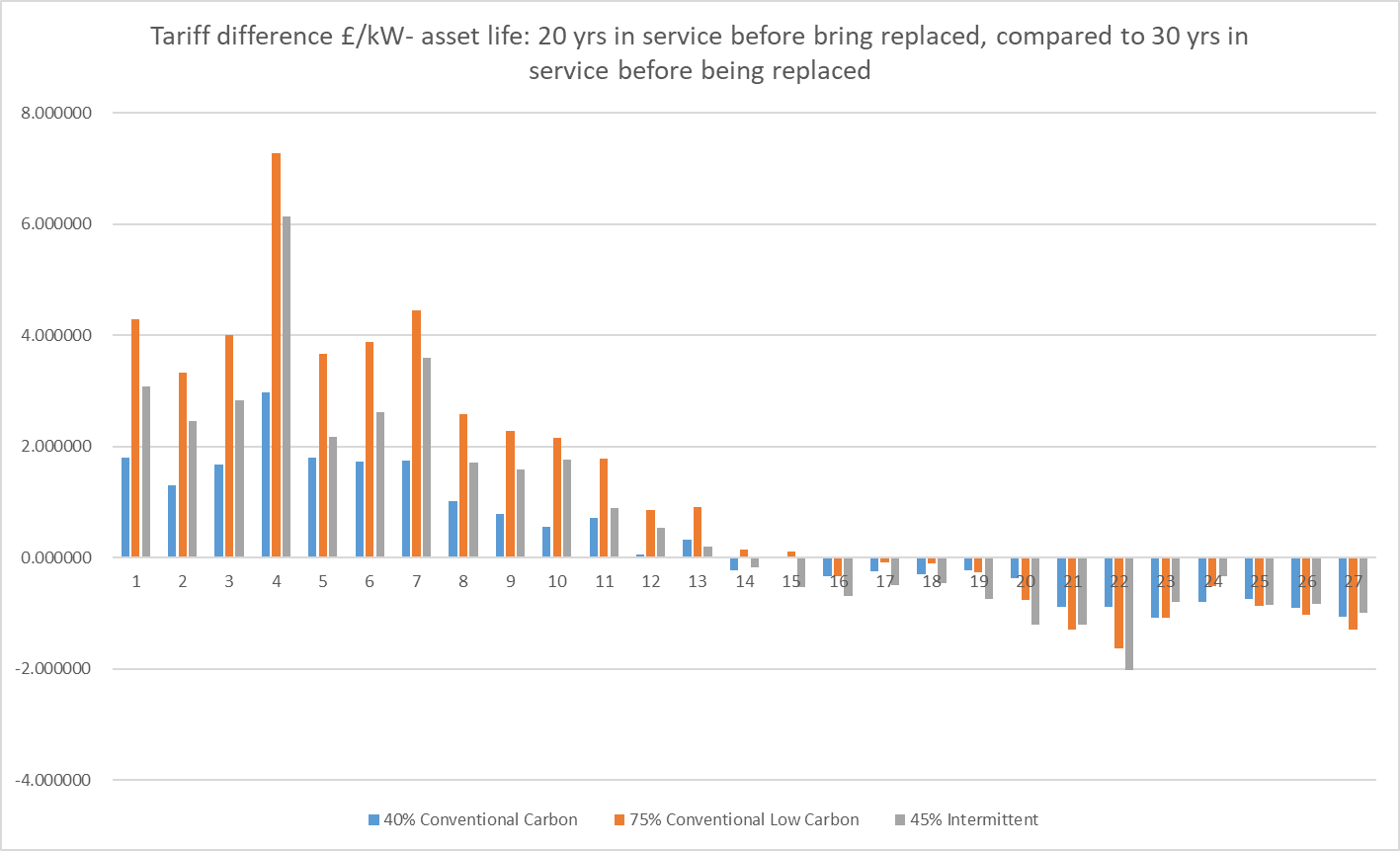
**Defaulting Rule for Asset Life Extensions**

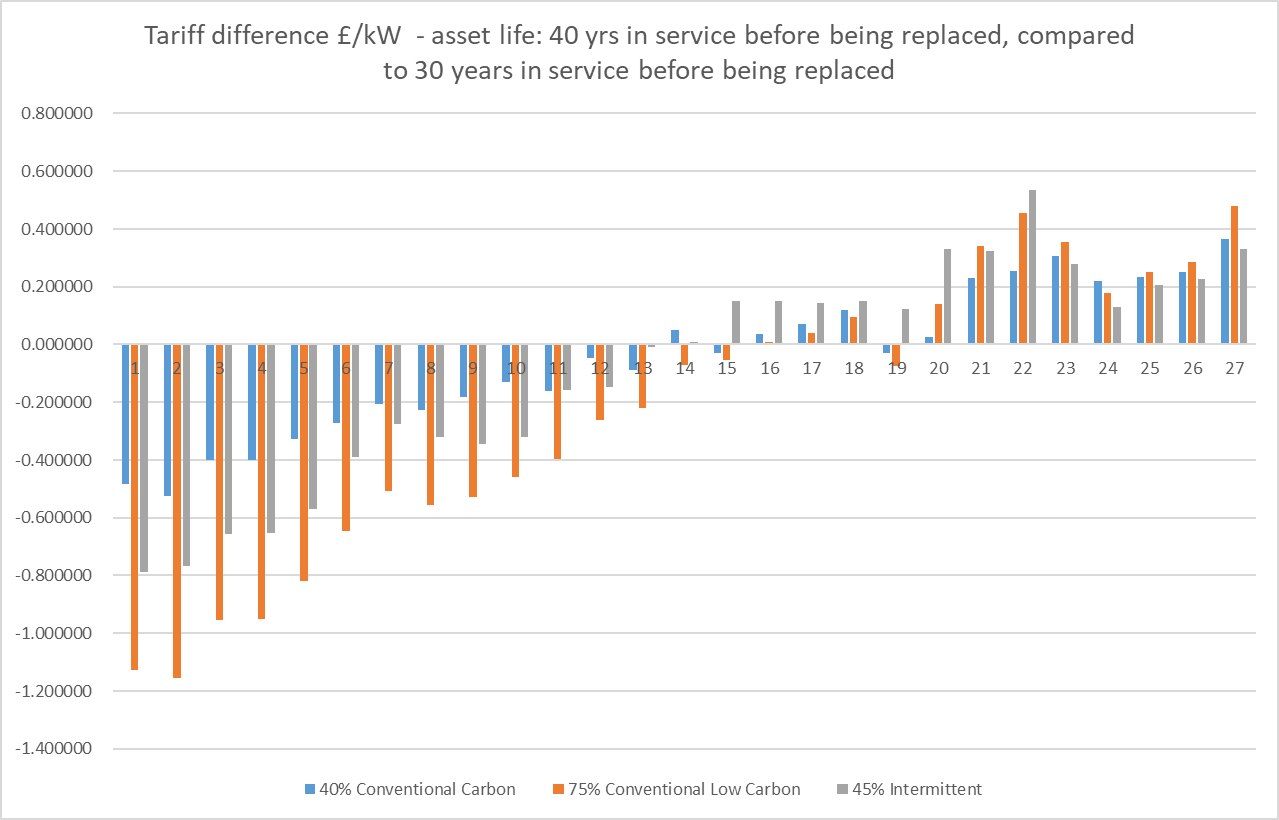
Once the solutions were clarified, there was a clear steer from the Workgroup that they need to see how the tariffs would be impacted by these solutions, to act as a sense check, before the Workgroup phase could be concluded.

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 X % 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](https://www.nationalgrideso.com/document/204196/download) 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]](#footnote-8) 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

Current historic data, up until recently..

**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.**

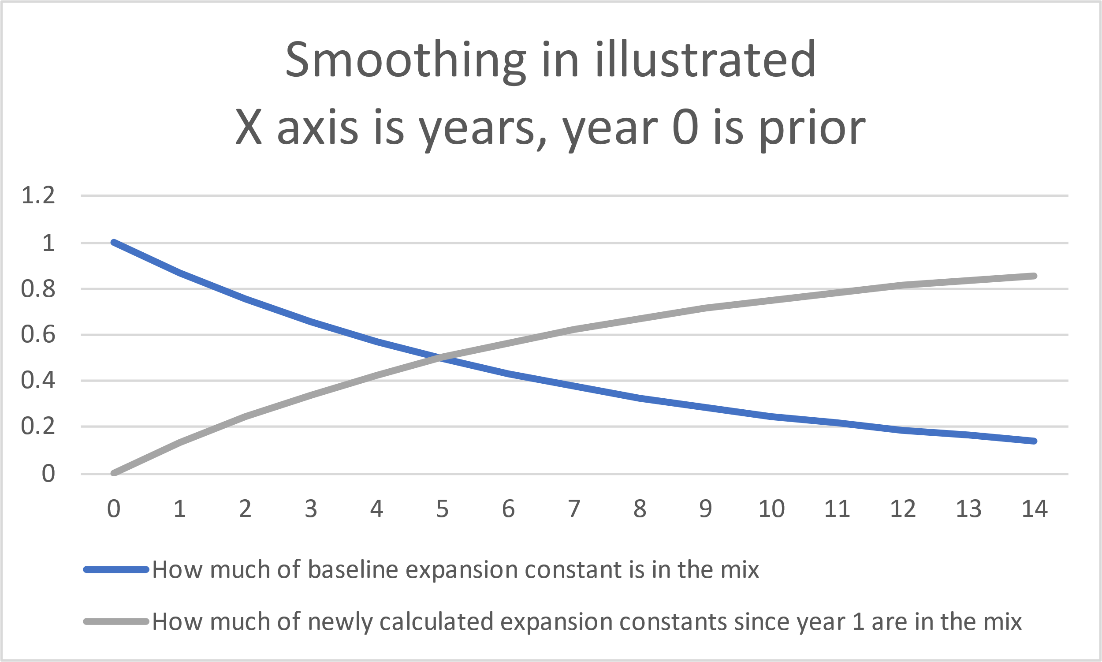
The 0.13 smoothing factor thus ensures that each new EC value for a given asset class is only given a weighting of 0.13, with a 0.87 weighting given to the previous year’s EC value for that asset class.  The choice of 0.13 for this parameter means that over 5 years, which is the same duration as a transmission 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.

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; and
2. The calculation after year 1 is performed each year using last year’s data bundled up with the previous rolling 10 years and apply a "smoothing" factor to mitigate volatility.

The Proposer of CMP375 originally favoured a smoothing factor of 20% as initially felt that 13% was potentially too sluggish. However, they amended this to 13% to align with the CMP315 Original given the rationale for 13% as set out above.

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 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”.



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.  Smoothing helps with this volatility whilst allowing the values to change 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/EF in a particular period.

**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 EFs 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 still calculated relative to the EC, which remains set as the cost of new build 400kV Overhead Line (OHL). However, as the 400kV OHL reinforcement category now includes other reinforcement types, the EF for 400kV OHL may differ from 1. An EC calculated for this analysis based on a published study into new build circuit costs – with a resulting value similar to that currently maintained by [CMP353](https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp353-stabilising). However, the other reinforcement types were costed separately, and as a result if a different EC was used (based on different input data), then the EFs would be scaled accordingly.

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.

Table

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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 2025 but that appears unlikely based on current timeline and the likelihood of Ofgem undertaking an impact assessment before making a decision.
* **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;

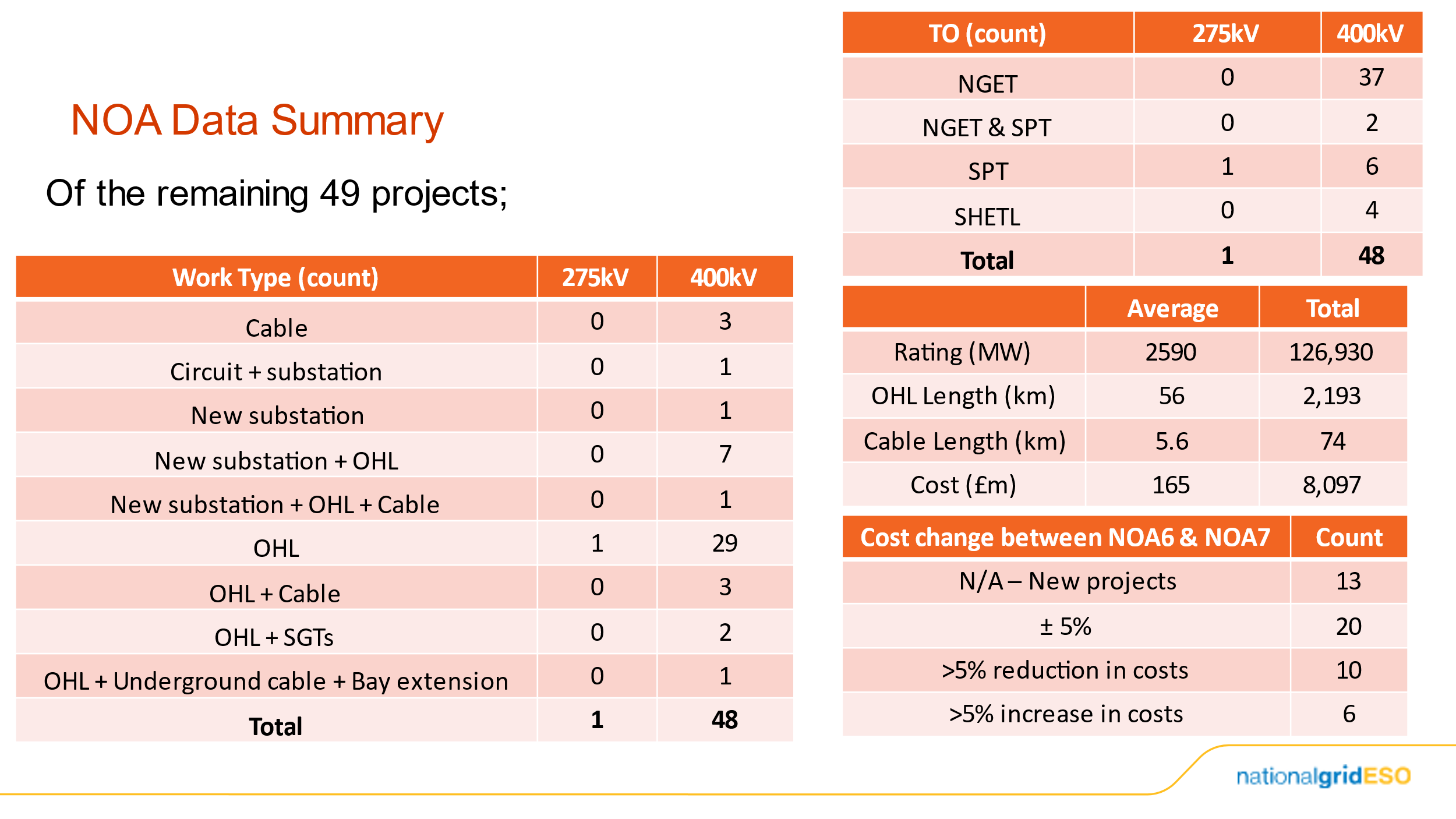
* Works purely for voltage (MSCs and Reactors – i.e. no MW capacity change)
* Power Flow Control Devices (i.e. no MW capacity change)
* Subsea links (circuit specific EF for these circuits)
* Works with optimal delivery date beyond 2033 (i.e. >10 years’ time)
* Insufficient data available (e.g. no ratings 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 9 below shows the output of this.

**Figure 9**



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.

|  |  |  |
| --- | --- | --- |
| 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.

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.

**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 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).

[placeholder for charts]

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.

Demand Tariffs

Generation Tariffs

Consumer Tariffs

Future Expansion Constant

## 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:**

1. 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;
2. 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);
3. 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;
4. Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency \*; and
5. 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)

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| --- | --- | --- | --- |
| **Workgroup Member** | **Company** | **BEST Option?** | **Which objective(s) does the change better facilitate? (if baseline not applicable)** |
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**CMP375**

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

**CMP375**

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

**Best Option – CMP375**

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| --- | --- | --- | --- |
| **Workgroup Member** | **Company** | **BEST Option?** | **Which objective(s) does the change better facilitate? (if baseline not applicable)** |
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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]](#footnote-9) | ☐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 |
| Annex 12 | Alternative and Workgroup Vote |

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” [↑](#footnote-ref-2)
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.”* [↑](#footnote-ref-3)
3. CUSC 14.15.59 [↑](#footnote-ref-4)
4. This could mean the depreciation period in the Expansion Constant could differ from the regulatory settlement [↑](#footnote-ref-5)
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.”* [↑](#footnote-ref-6)
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](https://www.spenergynetworks.co.uk/pages/transmission_connections.aspx) [↑](#footnote-ref-7)
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 [↑](#footnote-ref-8)
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. [↑](#footnote-ref-9)