

Single Electricity Market Committee

Transmission Use of System Charging: Methodology for All-Island Generation Tariffs

Consultation Paper

SEM-08-067

11th June 2008

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I INTRODUCTION

In July 2006 and June 2007, the Commission for Energy Regulation (“CER”) and the Northern Ireland Authority for Utility Regulation (“NIAUR”), collectively known as the Regulatory Authorities (“RAs”), published consultation papers on all-island generation transmission use of system (“TUoS”) charging intended to apply from 1 January 2008. Corresponding decision documents were published in March 2007 and July 2007. The first of these decision documents established that, under the Single Electricity Market (the “SEM”), the locational TUoS charges paid by generators should be calculated using a methodology broadly based on that presently employed by EirGrid in the Republic of Ireland, whilst the second reported more detailed decisions concerning the methodology to be used.

Since then, EirGrid and SONI, the system operators in the Republic of Ireland and Northern Ireland, respectively, have been developing indicative tariffs in accordance with the methodology. Certain aspects of the methodology, principally the costings of network elements and the assumed generation scenarios, have had a more significant impact on the resulting tariffs than was first anticipated. As a result, SEM Committee¹ deferred the application of all-island generator TUoS tariffs until 1 October 2008, pending further investigation, with the jurisdictional TUoS tariffs carried over in the meantime.

The purpose of this paper is to describe the results of indicative calculations and analysis, and to set out the RAs’ proposals on the methodology for the derivation of all-island generator TUoS tariffs by the system operators. Following a review of comments received, the RAs intend to publish a decision paper on the methodology for calculating all-island locational generator TUoS tariffs in July. The actual tariffs to apply from 1 October 2008 will then be prepared by the system operators and published for consultation by the RAs in August with final tariffs published in September.

¹ The SEM Committee is established in Ireland and Northern Ireland by virtue of Section 8A of the Electricity Regulation Act 1999, as inserted by Section 4 of the Electricity Regulation (Amendment) Act 2007, and Article 6(1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007, respectively. The SEM Committee is a committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter. The SEM Committee has determined that all-island locational transmission use of system tariffs for generation is a SEM Committee matter within the meaning of the legislation.

The structure of the remainder of the paper is as follows: Section II describes the background to this paper; Section III discusses network costings; Section IV discusses the impact on generator TUoS tariffs of using a variety of generation scenarios; whilst Section V a number of other issues that have arisen from the further development of all-island generator TUoS tariffs. Section VI gives recommendations and invites views. Indicative TUoS tariffs are shown in Appendix A to illustrate the implications of various methodology options, including the one proposed.

II BACKGROUND

High-Level Design

In June 2005, the RAs published a High Level Design Decision Document², (the “HLD”) setting out the high-level design features of the SEM, which had been determined following a process of consultation with industry participants. In respect of TUoS charging, the paper stated:

- *“It is proposed that a shallow policy is adopted in the SEM As a corollary of shallow connection charges, generators should pay a locational charge as part of their TUoS”;*
- *“The Regulatory Authorities propose that the details of TUoS locational charges be considered in parallel with the development of the detailed rules”*

July 2006 Consultation

In July 2006, the RAs published a consultation paper on TUoS charging for the SEM³. This paper noted that the methodology for determining generation TUoS tariffs used by EirGrid broadly fulfilled the requirements of the High Level Design (HLD), and proposed that, subject to the outcome of consultation, the EirGrid methodology should form the basis of the approach adopted for the SEM. The paper also questioned whether, in the calculation of generator TUoS tariffs, the simple pro-rata scaling of generation to meet a winter peak demand was appropriate for the all-island market given the greater proportion of high merit plant in the North and of low merit plant in the South. The same scaling applied across the whole system would thus result in unrepresentative power flows on the all-island system. It was proposed that further work would be done in this area, although it was suggested that a desirable principle was that the dispatches used for developing TUoS tariffs should reflect the scenarios used for investment planning.

The July 2006 consultation paper also reported that the existing EirGrid methodology used a set of replacement costs for each transmission circuit and each transmission station. It noted that no equivalent dataset, in a form suitable for calculating transmission use of system charges, existed for

² “The Single Electricity Market (SEM) High Level Design Decision Paper”, AIP/SEM/42/05, 19 June 2005.

³ “Connections and Transmission Use of System for Generation: A Consultation Paper”, AIP/72/06, July 2006.

Northern Ireland. Furthermore, EirGrid considered that the replacement costs it had been using were due for review, which would involve undertaking a survey of modern equivalent assets to replace the existing network infrastructure. As an alternative to actual replacement costs, it was proposed to use a number of standardised costs. Further, the July 2006 consultation paper presented an indicative all-island tariff, having a range of broadly consistent with ranges seen with previous ROI-only tariffs, e.g. -€1/kW/yr to +€13/kW/yr in 2006, and -€4/kW/yr to +€14/kW/yr in 2005.

The decision paper⁴, published in March 2007, confirmed that the proposals in the July 2006 consultation paper would be adopted.

June 2007 Consultation

A paper published in June 2007⁵ consulted on more detailed aspects of the proposed methodology.

Following discussions between the system operators and the RAs, it was proposed that, in lieu of the pro-rata scaling of the existing EirGrid methodology, TUoS tariffs would be developed on the basis of a number of scenarios which, in aggregate, represented the spectrum of running conditions used in investment planning analysis. It had been noted that the plant margin on the all-island system had increased to over 40%, and that whilst the plant margins in Northern Ireland (NI) and Republic of Ireland (ROI) were similar, the system in the ROI has a higher proportion of wind generation as well as plant that, on an all-island basis, has the low merit. Thus pro-rata scaling of generation, on an all-island system, led to low assumed flows on the interconnector that were considered to be unrepresentative of typical conditions, and unrepresentative of the basis on which investment in the transmission network is planned.

Instead, it was proposed to use a set of twelve scenarios spanning: winter peak, with 0% wind; summer peak demand with 100% wind; summer peak with 0% wind; and summer minimum, with 100% wind. For each of the four conditions, the system operators had suggested considering three assumptions about flows on the North-South interconnecting circuits: maximum North-South; maximum South-North; and the flow determined under an all-island merit order dispatch. Tariffs would be calculated for each

⁴ "Transmission Use of System Charging: Decision Paper", AIP-SEM-07-50, 15th March 2007

⁵ "Transmission Use of System Charging Tariff Methodology Consultation Paper", AIP-SEM-07-262, 18th June 2007.

of these scenarios, and then, for each individual generator, the maximum tariff across the complete set of scenarios would be used for the final tariff. The rationale for this approach was that it could be any of the individual scenarios that could drive the need for transmission system investment in respect of any given generator. Taking the maximum value across the scenarios would reflect the extent to which each generator made use of the transmission system in any of these scenarios and, on the basis that the scenarios were representative of the running conditions used in investment planning analysis, the amount of transmission necessary to accommodate that generator.

It was proposed in the June 2007 consultation paper that tariffs would be normalised both before taking the maxima (to ensure each tariff was being compared on a like-for-like basis) and after (to ensure the correct overall revenue recovery).

For network costings, the June 2007 paper proposed a number of categories. For transmission circuits, different costs would be defined for cable and for overhead line, for each different voltage level, and for each jurisdiction. For transmission stations, costs would be identified for switchgear bays and for switchgear, varying by voltage level and by jurisdiction; for transformers, different costs would be defined for different voltages, different capacities, and for each jurisdiction.

The July 2007 decision document⁶ made a number of detailed decisions. The RAs acknowledged that the suggested approach remained 'work in progress' and subject to the resulting tariffs being satisfactory, and decided that the draft tariffs would be consulted upon. The scenarios, particularly the summer high wind scenarios, would be kept under careful review. The RAs also reported that they awaited the system operators' proposals for harmonising the categorisation of costs into wires and non-wires costs as between the two jurisdictions.

December 2007 Industry Update

In December 2007, the RAs published an industry update on progress in the development of the tariffs. This stated that during the calculation of draft all-island locational TUoS tariffs for generation, initial draft tariffs appeared to have been significantly influenced by, principally:

⁶ "Transmission Use of System Charging Tariff Methodology Decision Paper", AIP-SEM-07-433, July 2007

- (1) updated figures for the costings of network components⁷ which are significantly higher than have been used previously in ROI-only locational tariffs; and
- (2) in conjunction with (1), scenarios other than the winter peak, that contribute under the new, but not the old, methodology⁸.

Accordingly, the SEM Committee considered that it was appropriate to undertake further investigation with the expert assistance of the system operators of these aspects of the proposed methodology and decided to continue transmission use of system charging on the basis of the existing jurisdictional approaches and to defer an all-island methodology until 1 October 2008.

⁷ See Section III.2.2 of AIP/SEM/72/06.

⁸ See Section III.1.2 of "Transmission Use of System Charging Tariff Methodology Consultation Paper", AIP-SEM-07-262, 18 June 2007.

III NETWORK COSTINGS

Since the July 2007 decision document, the system operators have undertaken indicative calculations of all-island generator TUoS tariffs. These calculations have used network data and generation scenarios for 2008, and an assumed revenue recovery requirement of €57.5m. In contrast, the calculations for the actual tariffs to run from 1st October 2008 to 30th September 2009 will use: further updates to transmission system network data; updated generation scenarios; the finalised revenue requirement for the tariff period; any other changes as a result of this consultation. Other aspects of the indicative tariff calculations were as described in the June 2007 consultation paper, albeit that a number of variations were explored, as described in the following sections.

The indicative tariffs are shown graphically, together with the 2007 tariff for comparison, in the Appendix as Figure 1a.

It is immediately apparent from these results that:

- (i) the range of individual generator tariffs is significantly greater than in the 2007 tariff;
- (ii) some generators that have been subject to relatively low tariffs under EirGrid's ROI methodology, now see high tariffs under the indicative all-island approach; and
- (iii) tariffs for generators connected in NI which are relatively high compared to many generators connected in ROI.

As stated in the December 2007 Industry Update, these features principally are due, firstly, to a substantial increase in the network costings that the system operators have proposed and, secondly, scenarios other than the winter peak being used in the proposed, but not the existing, methodology. Network costings are discussed below, with generation scenarios discussed in Section IV, and other aspects of the methodology in Section V.

Figure 1b shows Figure 1a replotted such that the x-axis is scaled by each station's MEC (Maximum Export Capacity), and thus gives an indication of the MW of generation capacity to which the tariffs apply. This shows that a number of the stations that are subject to higher tariffs than the existing tariffs are smaller generating stations.

III.1 Network Costing Data

The reverse MW-mile calculation, which forms a key part of the EirGrid methodology that it has been decided to adopt for the all-island locational generator TUoS tariff, calculates for each circuit the MW flow which it is deemed is caused by each generator under a given scenario. These MW flows are multiplied by the corresponding cost of each circuit (expressed as a cost per MW of circuit rating) to calculate a cost attributable to that generator. Each generator's tariff is then derived by taking the aggregate costs attributable to that generator divided by the output of the generator in the scenario. It follows that locational differentials are directly related to the network costings.

EirGrid has reported network costings, as follow:

Table 1: Existing and Proposed Updated OHL Costings - EirGrid

Lines		Costings in current ROI-only tariffs (inc 35% "grossing up")	Proposed costings (inc 40% "grossing-up")
Types	MVA	2007 €/ circuit km	2007 €/ circuit km
110kV 200's ACSR SC	107 to 126	99,606	208,153
220kV 600's ACSR SC	431 to 518	285,826	742,313
400kV 2*600's ACSR SC	1424 to 1713	428,740	1,235,234

Table 2: Existing and Proposed Updated Cable Costings - EirGrid

Cables & Cable Ends		Costings in current ROI-only tariffs (inc 35% "grossing up")		Proposed costings (inc 40% "grossing-up")	
KV	MVA	Cable	Cable End	Cable	Cable End
		Year 2007 €/km	Year 2007 €	Year 2007 €/km	Year 2007 €
110	120	649,605	86,615	1,401,974	115,910
	250	1,082,676	108,267		
220	250	1,158,462	216,535	1,877,971	278,184
	500	2,154,523	259,843		

Table 2 shows that costings for underground cables, as opposed to overhead lines, have not increased significantly between:

- (a) the costings used in the 2007 ROI-only tariff, which are based on estimates in 2000, indexed up to allow for inflation; and
- (b) updated estimates, proposed to be used for the all- island tariff.

However, Table 1 shows substantial increases in costings for overhead lines between the values used in the 2007 ROI-only tariff and the updated estimates proposed for the all-island tariff. Specifically, for 110kV overhead lines the proposed costing of €208,153/km is over twice the existing costing of €99,606/km; for 220kV the proposed costing of €742,313/km is 2.6 times the existing figure of €285,826/km; whilst for 400kV overhead lines the proposed costing of €1,235,234/km is almost triple the existing costing of €428,740/km. It is these large increases in network costings that cause the greatly increased range of the individual generator tariffs.

The RAs asked the system operators to explain what has caused these increases. The system operators explained that the network costing used to calculate the existing ROI-only tariffs are based on costs derived in 2000, indexed up by the Consumer Prices Index. The system operators explained that the updated costings are based on costs calculated during the ROI transmission price control review for 2006 to 2010⁹. The system operators stated that the costs of transmission assets have increased far in excess of general inflation, and hence the figures as indexed by CPI had fallen significantly behind actual costs. The system operators suggested reasons for this were that:

- (i) metal prices had increased dramatically over the period and ‘general market tightness’ due to strong economic growth in China and the Far East;
- (ii) the “grossing up” factor, which the RAs understand is applied to account for various overheads, had increased from 35% for the 2001-2005 figures to 40% for the 2006-2010 figures.

In addition to these increases in the capital cost of overhead lines, the system operators explained that there had also been an increase in the factor used to

⁹ See Table 10.5 of “2006-2010 Transmission Price Control Review: Transmission Asset Owner (TAO) and Transmission System Operator (TSO). A Decision Paper”, CER/05/143, 9 September 2005. Note that the system operators have stated that the unit costs in Table 10.5 include overheads that have not been included in Table 1.

convert capital costs into annualised costs which are, in turn, used in the reverse MW-mile calculation to determine locational differentials (see Table 3).

Table 3 - Comparison of Previous and Proposed Annualising Factors

	Current ROI-only tariffs	Proposed
Rate of Return	4.35%	5.63%
Depreciation	2.5% (40 years)	2.0% (50 years)
Operation & Maintenance	1.2%	1.2%
Total	8.05%	8.83%

SONI described that it proposes to use a complex menu of costs provided to it by NIE, detailing circuits and the various components of line bay and station costs. The main elements are shown in Tables 4 and 5.

Table 4: Proposed OHL Costings - SONI

Lines		Proposed Costings
Types	MVA	2007 £ / circuit km
110kV Single Circuit, Wood Pole	As per SYS	206,630
110kV Single Circuit, Steel Tower	As per SYS	247,690
275kV, 2x400mm², Double Circuit	As per SYS	1,297,000

Table 5: Proposed Cable Costings - SONI

Cables & Cable Ends		Proposed Updated Costings Including "on-costs"	
KV	MVA	Cable	Cable End
		Year 2007 £ / circuit km	Year 2007 £
110	As per SYS	1,283,000	147,000
275	As per SYS	1,660,000	169,000

To these costs, line bay and station costs, including breakers, have to be added. For the purposes of the TUoS tariff calculation, SONI proposes to use an annualising factor of 7.55%. The ratings used for circuits are, the RAs understand, to be as per the ratings stated in the Seven Year Statement.

Not having had a locational TUoS tariff, SONI does not have previous network costings that are equivalent to those used in EirGrid's existing ROI-only tariff. Nevertheless, SONI's estimate was that recent increases in transmission costs have been in the region of 10% a year.

III.2 Discussion

Clearly the cost increases reported by the system operators for overhead lines (although not for cables) are substantial. Consequently, the RAs' concern is whether the new, higher costs represent a new long-term price for certain transmission plant or whether tightness in the market for such equipment is likely to be temporary, alleviated by a dropping off of demand or an expansion in manufacturing capacity.

The Regulatory Authorities note that the price control review for National Grid in GB has also noted increased costs in overhead line costs. Ofgem's consultants, KEMA¹⁰, reported that the outturn cost of overhead line schemes that outturned in excess of estimates suggested a 74% increase in costs over the course of the price control period. KEMA reported also that National Grid didn't supply comparable figures for schemes outturning *below* estimates, thereby making it difficult to draw a conclusion as to the average increase.

¹⁰ "Review of the Electricity Transmission Asset Management Policies and Processes as adopted by National Grid Electricity Transmission (NGET) within England & Wales and Assessment of Implications for Capex for 2007/8 - 2011/12", KEMA Ltd., 25 Sep 2006.

Similarly, a report for the Edison Foundation in the US by Brattle Group¹¹ also refers to increased demand by China as possible source of the increase in both raw material prices and finished products. In particular, Brattle states, “recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases”. The report refers to the Handy-Whitman Index ©, which the RAs understand is well recognised in the US for the purposes of ratemaking. Indices of a number of component categories are provided and, although the index for transmission costs shows rises significantly above inflation, the increase is of the order of 25% over the period 2000 to 2005, with further increases of around 17% in the following two years. When the fall in the value of the dollar is taken into account, increases denominated in either Euro or Sterling are lower.

III.3 Options for Network Costings

Various options exist for the network costings to be used in the reverse MW-mile methodology:

Option 1: Replacement costs as per system operators’ stated costs

Whilst the system operators maintain that this is the most appropriate basis for calculating the locational TUoS price signals to generators, the RAs are concerned at the possible volatility of this cost-driver. On the basis that the purpose of the locational price signals is to signal long-term differential costs imposed by generators at different locations, then the RAs would want to have assurance that the network costings are not reflecting what might be short-term variations due to transitory conditions in the market for transmission equipment.

Option 2: 20% forward-looking costs / 80% historic regulatory asset values

Under EU Directive 1228/2003¹², ERGEG published draft ITC Guidelines¹³ for a European inter TSO compensation mechanism, whereby system operators that host power flows across their systems are compensated by other system operators whose systems are determined to be the source or destination of

¹¹ “Rising Utility Construction Costs: Sources and Impacts”, The Brattle Group, September 2007.

¹² “Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity”.

¹³ “ERGEG Draft Proposal on Guidelines on Inter TSO Compensation”, E06-CBT-09-08, 10 April 2006

such flows. The Directive states that, “*The costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure*”. The ERGEG guidelines interpret this as the costs being 80% based on regulated values and 20% on the forward-looking “Long-Run Average Incremental Cost” (or “LRAIC”).

It could be argued that it would be inefficient for the cost of transiting power *across* a system and the cost of transferring power *within* a system to be calculated on different bases. This would suggest using the approach recommended in the ERGEG guidelines also as the basis for network costings for the all-island locational generation TUoS tariff methodology.

Figure 2a illustrates the effect on the indicative 2008 tariff of using this option, on the assumption that the resulting costs are 50% of the full updated network costing.

EirGrid has stated that it does not have the appropriate data available to implement this approach. The RAs believe that, in view of this, the EirGrid’s existing network costings, indexed by CPI, could be used as a reasonable proxy for the regulated values.

Notwithstanding that the ERGEG guidelines have not yet been fully implemented, this is the option the RAs are minded to adopt.

Option 3: Rolling average with previous costs

Recognising that there is some evidence that costs may have increased, one option would be to use a rolling average of the costs for the current year and the costings as used for a number of preceding years (inflated by CPI as appropriate). This approach would also help reduce tariff volatility by:

- (a) mitigating volatility in locational differentials arising directly from the network costings; whilst
- (b) the average level of tariffs is driven by the revenue requirement, which is inherently less volatile.

This option can be regarded as a variant of Option 2, in that the most recent costs are averaged with previous costs. In Option 2 the previous costs are the historic, regulatory asset values, whereas in Option 3 the previous costs are estimates of the replacement values in previous years.

The SOs have pointed out that no previous costs, equivalent to EirGrid’s, exist for SONI. However, a pragmatic solution would be to factor the proposed

SONI costs by the ratio, for comparable assets, of the rolling averaged to proposed replacement costs for EirGrid.

Figure 2b illustrates the effect on the indicative 2008 tariff of using a three-year rolling average, with the assumption that the resulting costs are, in the first year, 60% of the full updated network costings. Note, however, that if the full updated network costings were to remain at the same level in subsequent years then these rolling averaged costs would be 80% of the full costings in the second year and 100% thereafter. A rolling average over a longer period would result in costs which started off lower and which increased more slowly. In contrast, under Option 2, the average would not increase in this way.

Option 4: Maintain consistency with current tariffs

The existing costings used to calculate the current generator TUoS tariff in ROI could be retained, subject to further indexation by CPI. This would have the advantage of maintaining consistency with the existing approach and eliminating the change in tariffs as a result of the recent, large changes in network costings. This option might also have merit if it were considered that the recent, large cost increases were transitory, and that the old costings, further indexed by CPI, were a more reliable indicator of long-run transmission prices. The network costings would, however, be less representative of more recent estimates of replacement costs.

The RAs recognise that, as with the rolling average approach, this option presents the problem that historic network costings for SONI in the form required are not available. However, a pragmatic approach could be adopted of identifying the most comparable EirGrid assets and using the relevant existing EirGrid network costing.

IV NEW SCENARIOS

Further significant changes to generator TUoS tariffs stems from the use of new scenarios in the derivation of the all-island locational TUoS tariffs. As described in the July 2006 consultation paper, the existing ROI-only TUoS tariff methodology uses a winter peak demand forecast combined with a pro-rata scaling of all generation to meet that forecast demand. In contrast the proposed all-island tariff uses a set of scenarios, intended to reflect the range of scenarios that drive transmission system investment decisions.

After further consideration, the system operators recommended reducing the number of scenarios from those described in the June 2007 consultation paper. Specifically, they recommended dropping the scenarios involving maximum North-South and maximum South-North flows on the interconnecting circuits between the two jurisdictions and, instead, using only the scenarios in which the flows on the interconnecting circuits are purely derived from the all-island merit dispatch. Furthermore, following review as recommended in the July 2007 decision document, the summer peak high wind and summer minimum scenarios have been adjusted to use a load factor of 80%, rather than 100%, for wind generators. Where an 80% load factor results in a wind generator causing a flow that opposes the aggregate flow in a circuit, it is possible that a 100% load factor would cause the aggregate flow to reverse, thereby making the generator contribute to the flow. This effect will tend to reduce tariffs for wind generators under the 80% load factor.

In addition to the change in network costs, these new scenarios, not previously considered in the calculation of the TUoS tariff, also have a significant effect on the indicative 2008 all-island tariff. Figure 3 shows the individual tariffs for the winter peak ("WP"), summer peak no wind (SP0%), summer peak high wind ("SP80%") and summer night minimum ("SNV") (also having the 80% wind load factor). The figure shows that the summer peak high wind scenario and, even more so, the summer night minimum scenario (which also has wind operating at 80% load factor) dominate the tariffs for a number of stations which had low tariffs under the existing ROI-only tariff. Conversely, the tariffs for generators in Northern Ireland are dominated by the summer peak no wind condition. The winter peak condition dominates for a number of generators, particularly in the Dublin area, for which tariffs were high also under the existing ROI-only tariff.

The system operators have assured the RAs that, whilst a load factor for wind of 100% may be too high, a load factor of 80% is a realistic figure against which the transmission system is planned. It would thus appear that, to the extent that certain generators see high tariffs under these summer high wind

scenarios, but not under the winter peak condition, such generators may have been making significant use of the transmission system without, under the 2007 ROI-only tariffs, incurring correspondingly significant charges. To the extent that this is the case, the higher charges due to the additional scenarios under the proposed new approach better reflect the generators' usage of the transmission system, and the RAs are minded to continue with this approach.

V OTHER ISSUES

During the course of producing the draft 2008 all-island tariffs, the system operators have considered further additional aspects of the EirGrid methodology.

V.1 Lightly-Loaded Lines

Under the current EirGrid methodology, lines with a total loading of less than 20%, are excluded (i.e. costed at zero) from the calculation of total costs attributable to each generator in the reverse MW-mile calculation. This, the RAs understand, has been a feature of the EirGrid methodology since 2005 and was introduced, at least in part, to mitigate year-to-year volatility in tariffs for individual generators. The rationale is that the total flow on such lightly-load lines can easily reverse as a result of even small year-on-year differences in patterns of generation and demand. Under the reverse MW-mile methodology, the reversal of flow on a line will result in the attribution of the cost of that line to an individual generator using that line going from positive to negative or vice versa, which can cause significant step changes to the resulting tariffs.

However, the system operators have been considering whether the exclusion of the costs of lightly-loaded lines is inappropriate when applied on an all-island basis. In particular they have suggested that different planning standards in the two jurisdictions result, under some scenarios, in a greater proportion of the network in Northern Ireland having aggregate flows of less than 20%. This would have the potential to lower the differentials between generators in Northern Ireland, as in Northern Ireland a proportionately greater number of circuits would no longer contribute to the calculation of locational tariffs. They also expressed concern more generally about the proportion of circuits over the combined all-island system that can have their costs omitted, at least under some scenarios.

Figure 4 shows the effect of including and excluding lightly-loaded lines, and seems to bear out the above hypothesis. Including lightly-loaded lines in the tariff calculation would appear to increase the locational differentials across plant in Northern Ireland. However, it would appear that the effect of including lightly-loaded lines is also significant on the ROI system, with some high tariffs in ROI becoming higher still, and some low tariffs in ROI becoming lower.

The RAs recognise that, to a degree, the precise criterion for excluding the costs of lightly-loaded lines, i.e. that the aggregate flow is less than 20% of the capacity, may be somewhat arbitrary. Nevertheless, the exclusion of

lightly-loaded lines per se may be justified on the grounds that, where flows are low, the uncertainties inherent in any predicted scenario must lead to some uncertainty as to the direction of flow in the lightly-loaded line. Under the reverse MW-mile methodology there is thus uncertainty as to whether the cost should add to or subtract from the tariff of affected generators. Furthermore, it is the RAs' understanding that the planning standards in the two jurisdiction, whilst different, are not significantly different, and it is for this reason that harmonisation of planning standards was not considered a priority issue for the SEM. It would appear also to be borne out by the similar effects in both NI and ROI as shown in Figure 4.

Accordingly, the RAs are of the view that it is not inappropriate to apply this aspect of the EirGrid methodology on an all-island basis. Accordingly, the RAs propose that lightly-loaded lines continue to be excluded from the calculation of tariffs, as per the existing EirGrid methodology.

V.2 Normalisation

In the June and July 2007 papers, the RAs considered that, prior to the finding of the maximum tariff for each generator across all the scenarios, the individual tariffs from each of the scenarios should be "normalised" first to achieve the same revenue recovery. The rationale for this approach was that, whilst the locational differentials emanating from the reverse MW-mile calculation can be relied upon, the absolute values are of less significance. Indeed a feature of the EirGrid methodology (and of similar calculations of locational TUoS tariffs by other system operators) is that the tariffs for all generators are shifted by an equal amount - by the addition or subtraction of a "postage stamp tariff" - in order to get the correct revenue recovery. Unless the individual tariffs were normalised, it was argued that scenarios with a higher overall revenue recovery would be more likely to contribute the maximum values to the final tariff than scenarios with a lower revenue recovery.

In developing indicative 2008 all-island tariffs, the system operators have argued that, whilst the "raw" tariffs produced from each scenario have different revenue recoveries, the absolute values from each scenario are significant. Specifically, the system operators have argued that the patterns of demand used in each scenario are representative of the demand patterns that are used for transmission system investment planning, and hence that the flows calculated during the reverse MW-mile calculation represent a good measure of the usage of the transmission system being made under that scenario. Thus, for example, were a scenario to have generation and demand well balanced in all parts of the system, it might be expected that the

calculated flows, the attributed costs, and hence the raw tariffs would be low. The system operators argue that these low raw tariffs would be a correct measure of the low usage made of the system under that scenario, and that to normalise the tariff to compensate for the correspondingly low revenue recovery would risk distorting this measure.

Figure 5 shows the effect of normalising (“NMN(+)FI”) versus not normalising (“MN(+)FI”) tariffs for the individual scenarios prior to combining into the single tariff. Normalising has the effect of increasing the tariffs that are set by the summer night minimum, 80% wind condition, for which the raw tariff revenue recovery is the lowest of the conditions, whilst reducing the tariffs set by the other conditions, for which the raw tariff revenue recovery is the higher.

On the understanding that the patterns of demand in each of the scenarios is, like the pattern of generation, representative of the running conditions that might be used in investment planning analysis, the RAs accept the system operators’ recommendation that scenarios should *not* be normalised to achieve equal revenue recovery before the maximum value is taken for each generator over all the scenarios. Instead the maximum value should be taken for each generator over the raw tariffs for each scenario.

The final tariff would, of course, be shifted, as is the case with the current EirGrid methodology, to achieve the required revenue recovery.

V.2.1 Normalisation by shifting or multiplication

As explained in previous consultations, a component of the tariff calculation is, having calculated the locational differentials between generators, to adjust these ‘raw’ tariffs to achieve the required overall revenue recovery. It was suggested that a possible alternative to shifting the ‘raw’ tariffs by a uniform €/kW amount would be to multiply the raw tariffs by a factor chosen to achieve the required revenue recovery. Given that it is proposed to take the maximum value across a number of scenarios, the resulting raw tariffs tends to give a high revenue recovery and hence the factor is substantially less than one.

This approach deviates from the approach previously adopted by EirGrid. It is also inconsistent with the approach used in the similar methodology used in GB. Furthermore, the RAs consider that, with the multiplier approach, a number of factors would affect the locational differentials that it is not sensible should do so. For instance, a change in the split of costs recovered in aggregate from generation as against demand would change the required revenue recovery from the all-island locational generator TUoS tariffs, hence the multiplier, and hence the locational differentials. Whilst there is no proposal to change this split, the point is that there is no particular property of

the existing 25%-75% split that is used that implies that the particular multiplier that results from it is in some way “correct”. Accordingly, the RAs are not minded to revise this aspect of the methodology.

V.3 Harmonisation of Wires and Non-wires Costs

The July 2007 decision paper stated that the RAs awaited the system operators’ proposals for harmonising the categorisation of costs into wires - charged 75% on demand and 25% on generation - and non-wires costs - charged 100% on demand - as between the two jurisdictions.

In the assumed revenue recovery requirement of €57.5m for EirGrid and SONI combined, used in the indicative calculation, the RAs understand that assumed revenue requirement of €47m for EirGrid was derived by reclassifying certain EirGrid wires costs - previously recovered through TUoS “Network Capacity” charges - as non-wires costs, to be recovered from demand through system services charges.

V.4 Volatility Mitigation

It has been a common criticism of locational TUoS tariffs that generators may connect on the basis of a given tariff only for that tariff to change adversely after connection resulting in subsequent changes to the pattern of generation, the network and the pattern of demand. This has led to the suggestion that measures should be introduced to mitigate such volatility in the tariffs.

However, new entrants should be taking decisions, not on the tariff at the time of connection, but expectations of the Net Present Value of tariffs over the lifetime of the generation project. In this regard, TUoS tariffs are no different to energy prices. This also implies that individual year-on-year changes are less significant than the cumulative TUoS charges over the lifetime of the project. Whilst any means of mitigating year-on-year variations may have appeal, they may have little effect on the NPV of lifetime tariff charges.

Nevertheless, the RAs recognise that this issue, i.e. uncertainty as to future TUoS tariffs, is regarded as important by some users. Possible options for mitigating changes in tariffs from year to year could include:

- (i) a rolling average of the tariff for each generator, say over three years. Note that this is distinct from the rolling average for network costs, as discussed earlier;
- (ii) capping changes (either positive or negative) in tariffs from year to year to a maximum amount say 5 €/kW;

- (iii) not modifying the tariffs as such, but requiring the system operators, say as part of the Transmission Forecast Statement and Seven Year Statement, to provide indicative tariffs for the six years following the tariff year for which actual tariffs are published. These indicative tariffs would necessarily be based on forecasts of generation and demand patterns and anticipated, but not necessarily committed, network developments. However, providing the assumptions were stated, users could take a view as to the relevance of the indicative tariffs; and/or
- (iv) apply zoning, whereby generators within defined zones are subject to the same, 'zonal' tariff, as opposed to a tariff specific to each generator. This would reduce volatility in tariffs only to the extent that the volatility occurred in the nodal tariff relative to the zonal average, rather than in the differences between zones. Clearly, the definition of zones, and changes in the definition of zones, would have an effect on the tariffs seen by individual generators.

Mindful of the substantial change compared to previous tariffs, the RAs propose that, for the tariff year 1st October 2008 to 30th September 2009, changes relative to the existing tariffs should be capped at +/-€5/kW. The possible continuation of this cap for subsequent years (albeit with adjustments for changes in the total allowable revenue) is also under consideration.

V.5 Indicative Proposed Tariff

Combining the above proposals, Figure 6a shows an indicative proposed tariff. This is based on:

- (i) 50% of the replacement costs, being an estimate of the updated replacement costs combined 20%/80% with historic regulatory asset values, or, in the case of EirGrid, existing network costings as a proxy for this data, as per the draft ERGEG ITC guidelines;
- (ii) tariffs based on scenarios for: winter peak; summer peak, 0% wind; summer peak, 80% wind; and summer night valley;
- (iii) the costs of lightly-loaded lines, specifically those loaded below 20%, being omitted from the calculation;
- (iv) harmonisation of wires and non-wires costs as per the system operators' recommendation of reclassifying certain previous EirGrid wires costs as non-wires costs;

- (v) normalising tariffs for the correct revenue recovery (after maximisation) by shifting rather than multiplying the raw tariffs.

Figure 6b shows the additional effect of the proposal to cap the tariffs at +/- €5/kW relative to existing tariffs.

VI RECOMMENDATIONS AND VIEWS INVITED

Subject to the views of respondents, the RAs propose that they would approve all-island locational generator TUoS tariffs for 2008/9 calculated on the basis of:

- (1) for SONI, the new estimate of replacement costs combined in the ratio 20%/80% with historic regulatory asset values, as per the draft ERGEG guidelines. For EirGrid, the updated estimate of replacement costs combined 20%/80% with the previous estimates of replacement costs. The details of this approach will be kept under review in subsequent tariff years should better information become available;
- (2) the four scenarios, comprising: winter peak; summer peak with 0% wind load factor; summer peak with 80% wind load factor; summer minimum with 80% wind load factor;
- (3) excluding the costs of lightly-loaded lines, as per the existing EirGrid methodology;
- (4) for each generator, taking the maximum tariff across the four scenarios, i.e. not normalising first to achieve a common revenue requirement;
- (5) normalising (after taking the maximum) for the correct revenue recovery by shifting by a €/kW amount rather than multiplying each of the generator's tariff by a factor;
- (6) tariffs to be capped at +/-€5/kW relative to the existing tariffs for the tariff year 1st October 2008 to 30th September 2009. The RAs are also considering whether it is appropriate that the duration of this cap should be extended and views are sought on this issue. The RAs also seek views on capping tariffs for new generators at the maximum (capped) tariff of adjacent existing generators.

Comments to this consultation will be carefully considered with a decision to be published in July, and proposed tariffs to run from 1st October 2008 to 30th September 2009 will be consulted upon in August and finalised in September.

VI.1 Views Invited

The RAs welcome the views and comments of interested parties on the issues discussed in this consultation paper. The RAs intend to publish comments received. If any respondent wishes certain sections of its submission to remain confidential, these sections should be submitted as an

appendix marked as confidential, such that the body of the submission can still be published.

Comments, preferably in electronic form, should be forwarded not later than 5.00pm on 27 June 2008 to jlynch@cer.ie and sarah.friedel@niaur.gov.uk or by post to:

John Lynch
Commission for Energy
The Exchange
Belgard Square North
Tallaght
Dublin 24

or

Sarah Friedel
NIAUR
Queen's House
Queen's Street
Belfast BT1 6ER.

Appendix A

Figures

Key to the Figures

In the legends to the figures, the following convention applies:

- 'NMN' denotes normalisation for revenue recovery before and after maximisation (see Section V.2)
- '(+)' denotes the normalisation has been achieved by shifting rather than multiplication (see Section V.2.1)
- 'FI' denotes that negative tariffs for wind generators has been floored at zero
- '50' or '60' denotes that network costs have been used which are 50% or 60%, respectively, of the full replacement values
- 'Capped' denotes that a cap on the change relative to the existing tariffs of +/-€5/kW/yr has been applied;
- 'WP', 'SP0%', 'SP80%' and 'SNV' denote the individual scenarios, Winter Peak, Summer Peak 0% Wind, Summer Peak 80% Wind and Summer Night Valley, respectively.

Figure 1a: Tariffs for 2008 using Full Updated Network Cost Data and for 2007

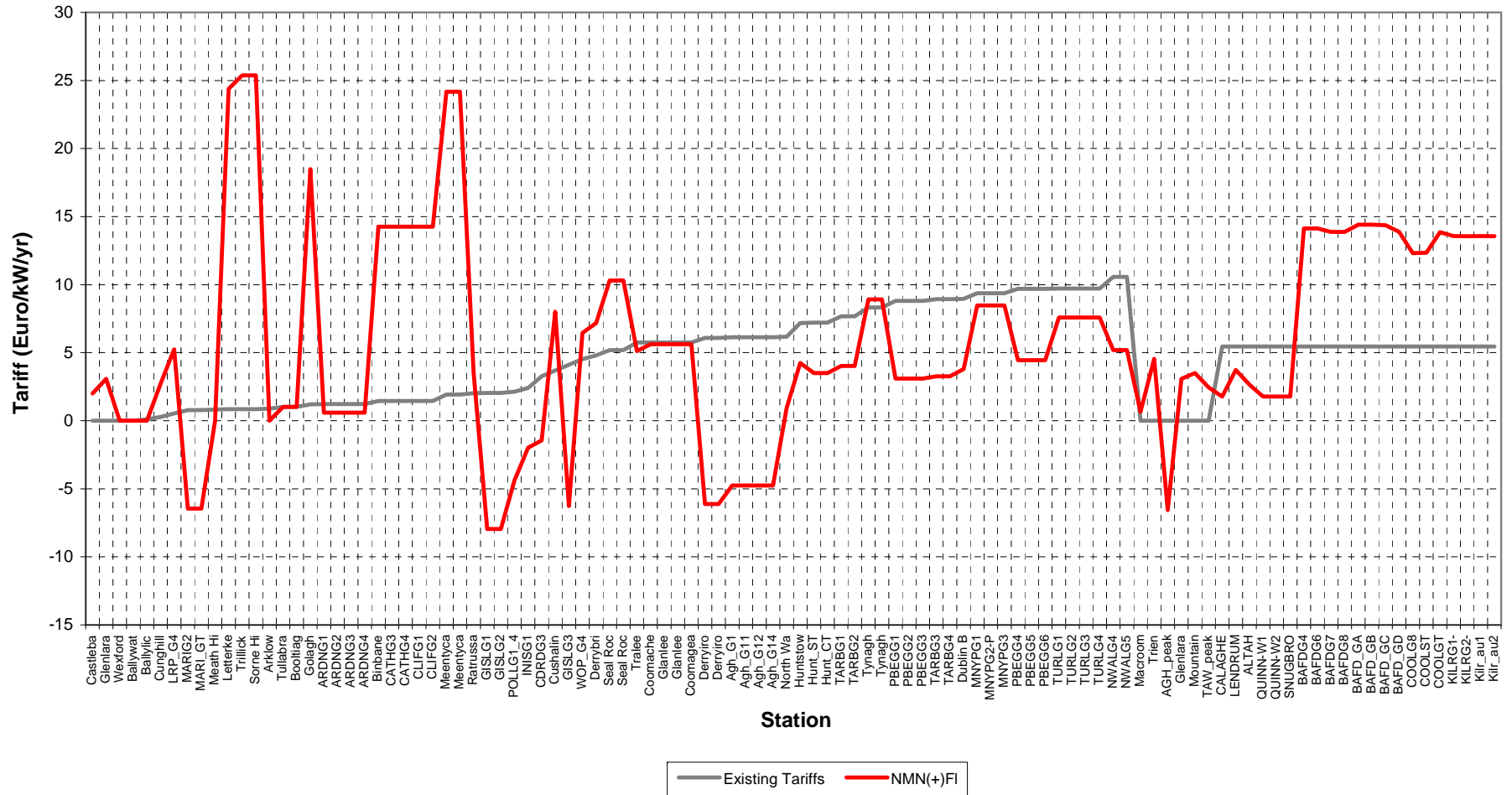


Figure 1b: Tariffs for 2008 using Full Updated Network Cost Data, X-Axis Scaled by MEC

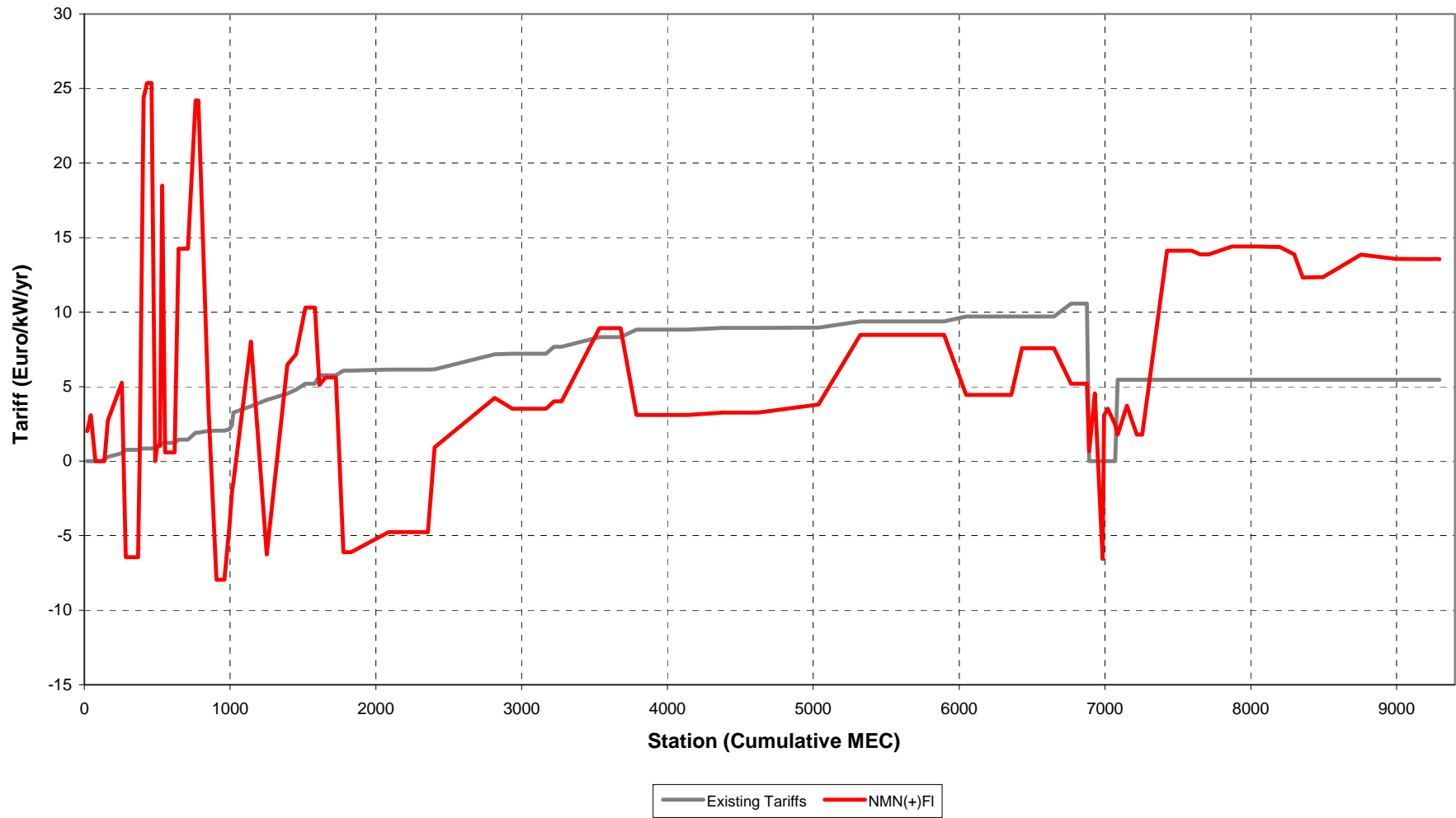


Figure 2a: Tariffs for 2008 using 50% of Updated Network Cost Data

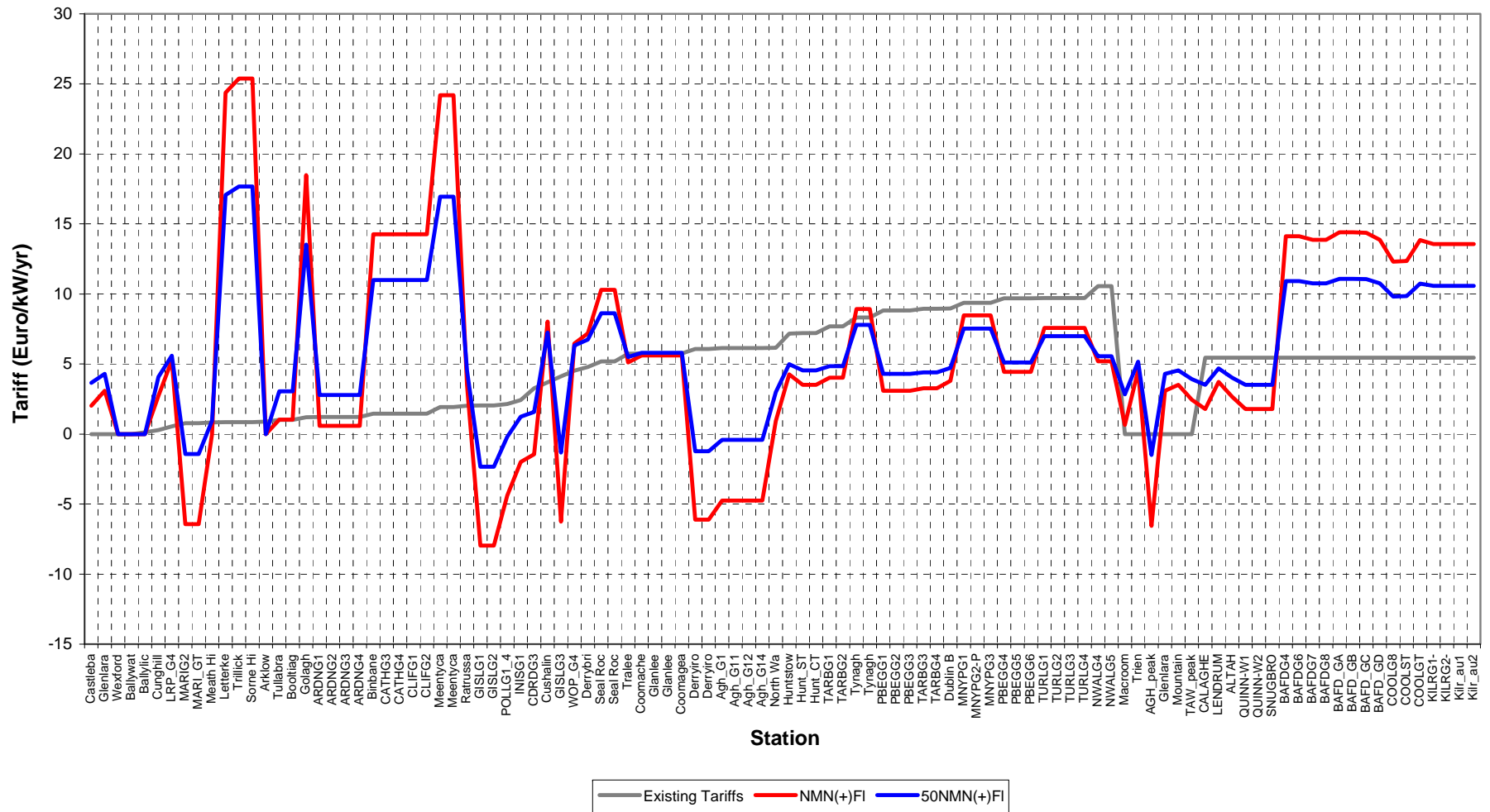


Figure 2b: Tariffs for 2008 using 60% of Updated Network Cost Data

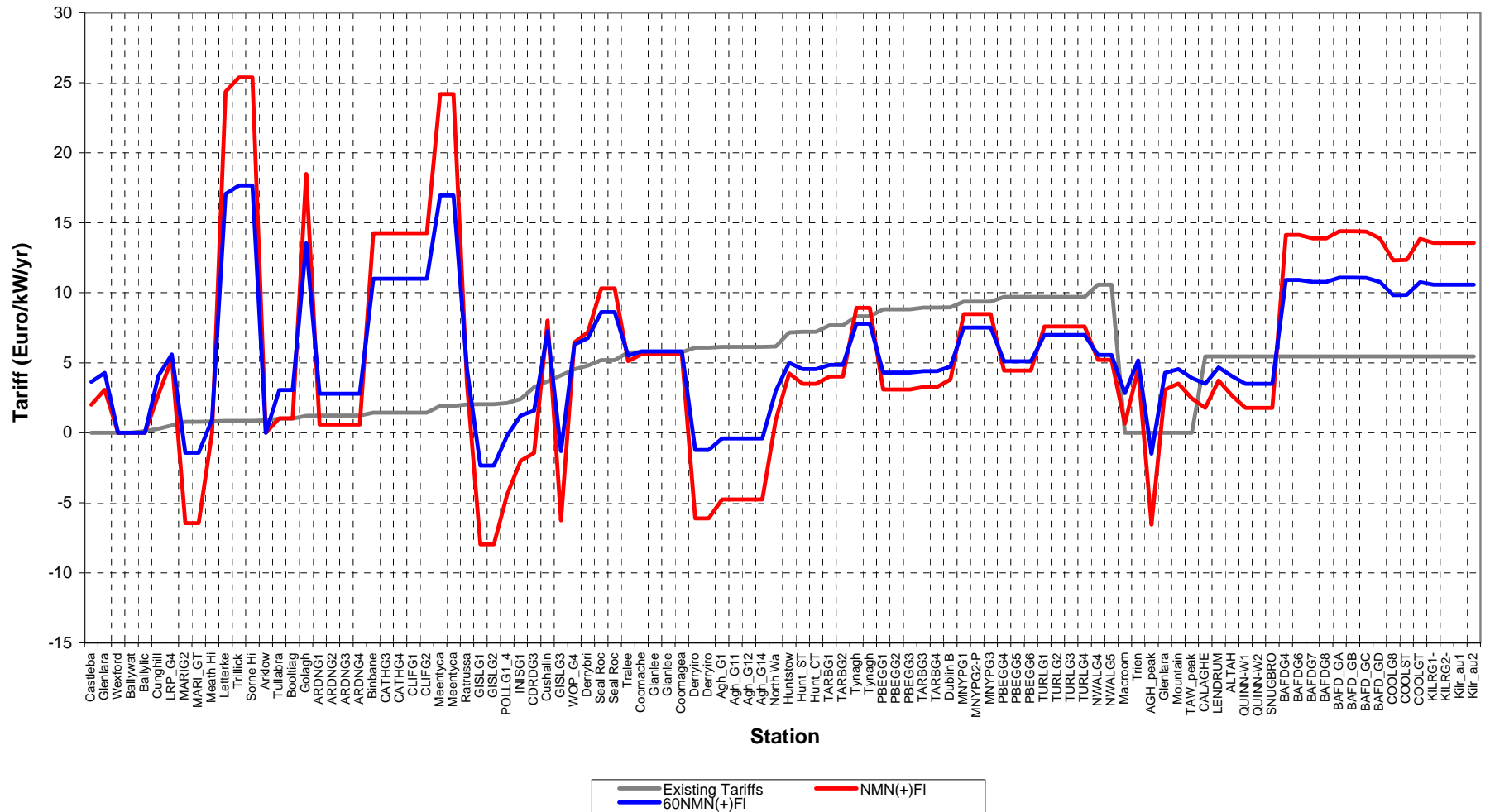


Figure 3: 'Raw' Tariffs from each Scenario

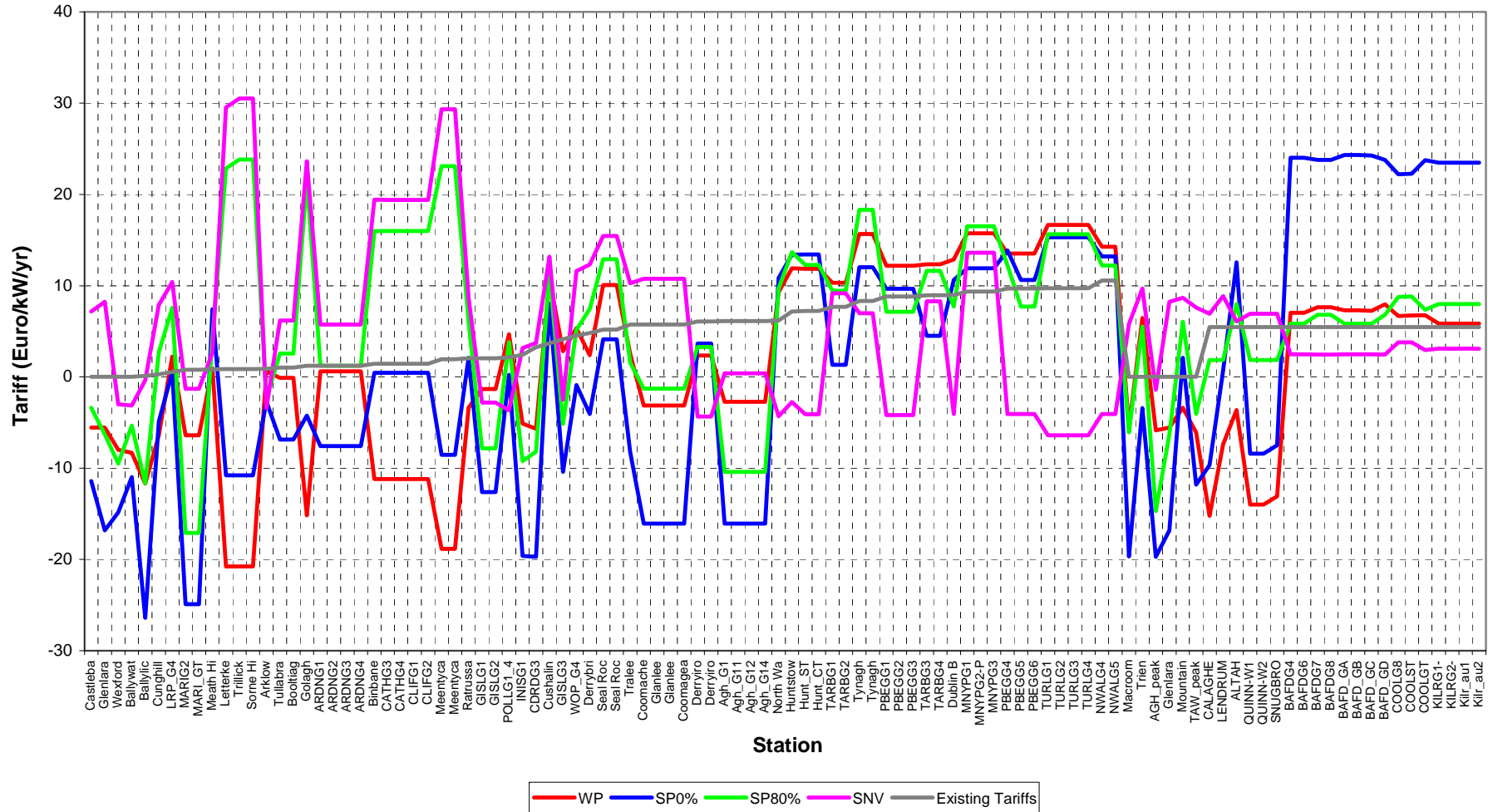


Figure 4: Effect of Including Lightly-Loaded Lines

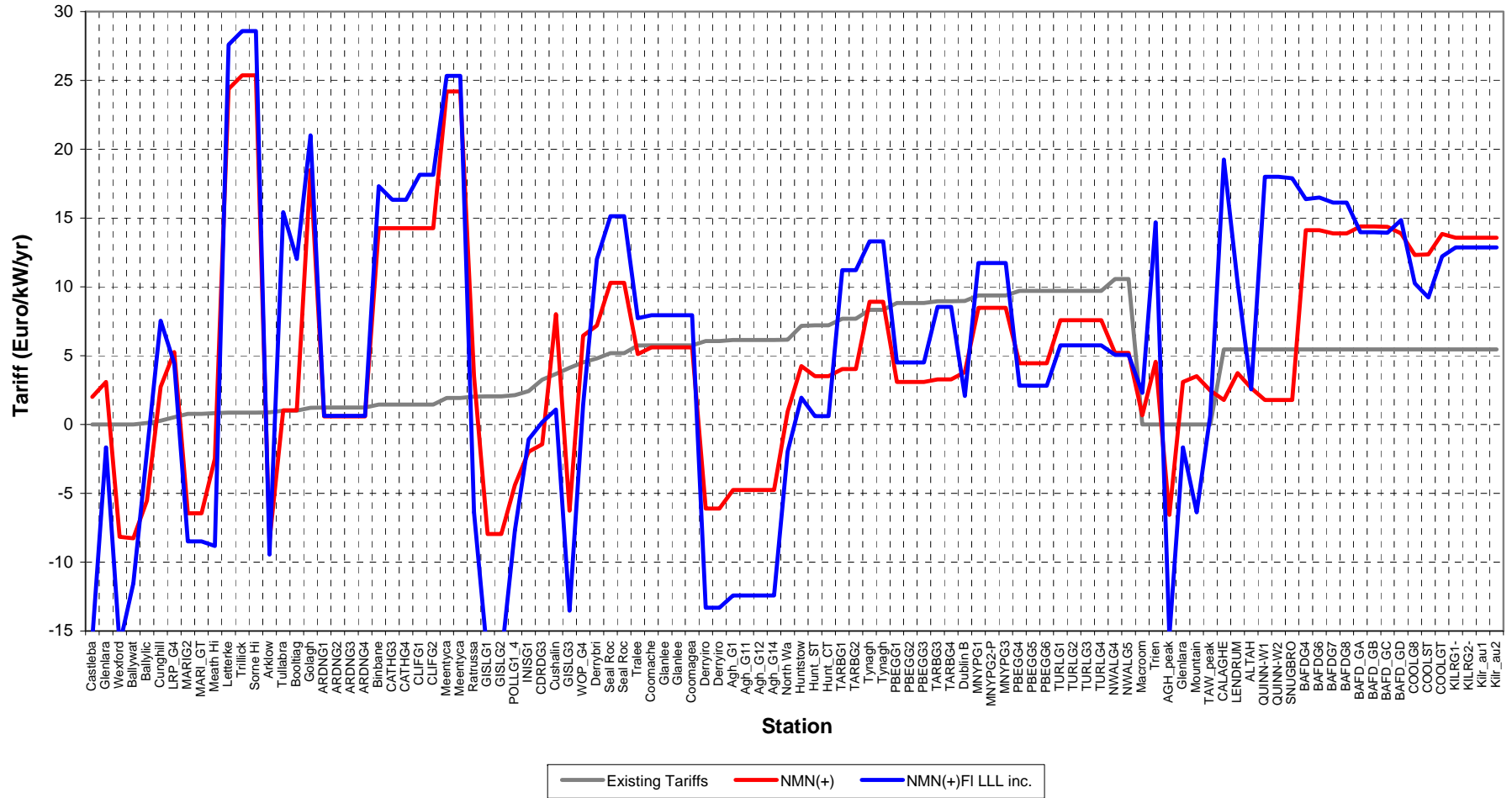


Figure 5: Effect of Normalising before taking the Maximum Value

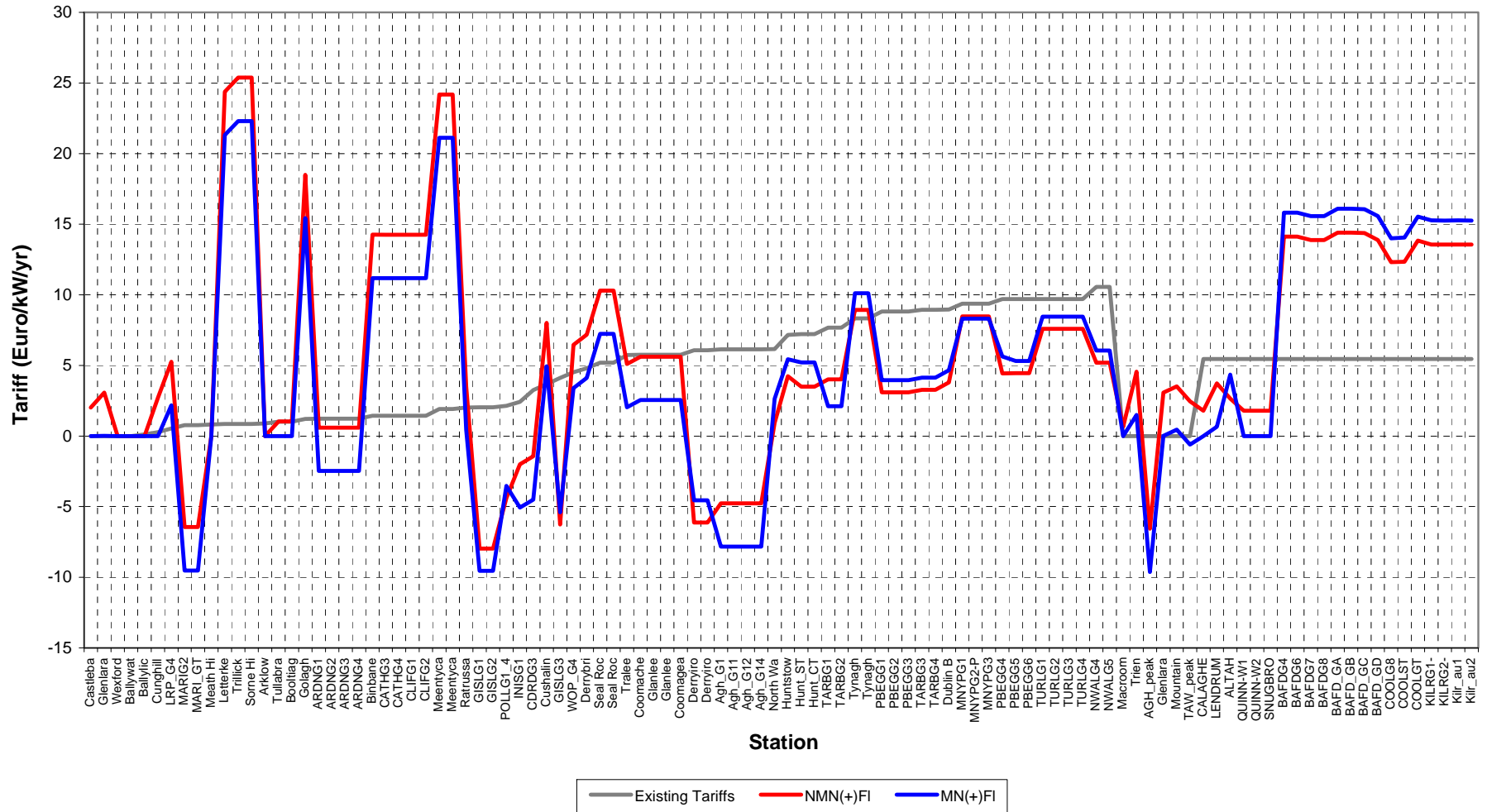


Figure 6a: Indicative Proposed Tariff and Existing Tariff

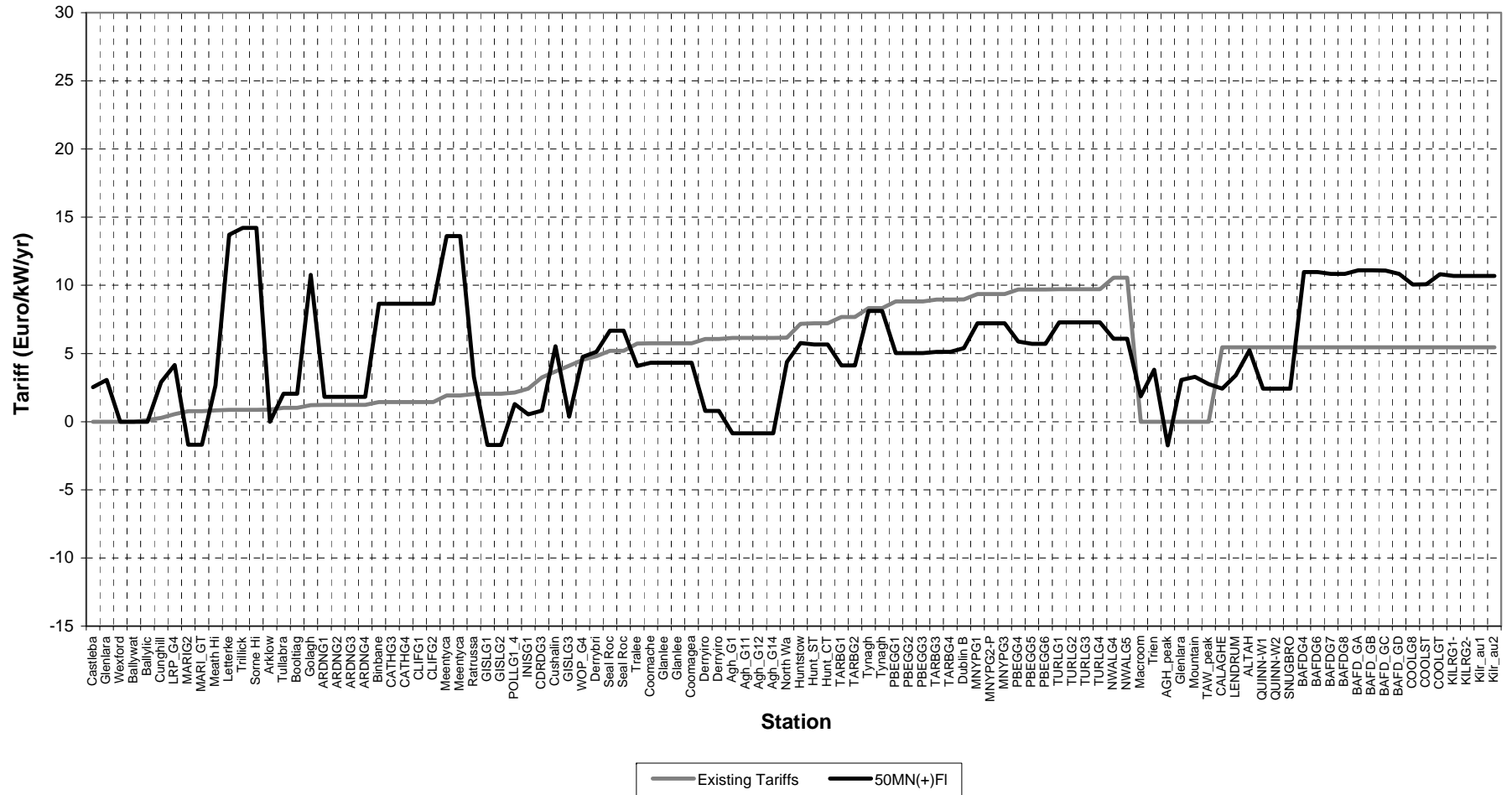


Figure 6b: Indicative Proposed Tariff (Uncapped and Capped) and Existing Tariff

