Preferred Options to be considered for the Implementation of Locational Signals on the Island of Ireland

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System Operator for Northern Ireland

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Executive Summary

Earlier this year the Regulatory Authorities (RAs) asked that the System Operators (SOs) carry out a review of the Locational Signals on the Island of Ireland as they apply to generation tariffs and losses. Feedback from the wider industry indicated that other factors such as the proximity to fuel sources tend to be more significant as locational influencers, however, TuoS and Losses may be determinant factors for marginal projects and hence require due consideration. The existing methodologies have been in place in both jurisdictions for a number of years. Since the losses methodology was first introduced in the Republic of Ireland both the generation mix and market have changed significantly. The connection of large amounts of wind to the system means that the effectiveness of ex-ante TLAFs may be somewhat different than that experienced when they were initially applied. Hence this changed environment indicates that a review is very appropriate at this time.

Demand tariffs were not considered as part of the project; however the impact of any changes to the generation tariff and losses methodologies on the demand side was taken into account. At present, there is no common approach for generation tariffs on the Island of Ireland. However, a common losses methodology has been applied since the SEM opened in 2007.

In an earlier phase of the project, the SOs carried out extensive consultation with the wider industry in the form of questionnaires and workshops. Based on feedback received and an extensive review of international best practice in tariff and losses methodology design, an Options paper was published in May. This paper outlined a total of 6 tariff and 4 losses options which were analysed over the last 3 months by the project team.

In order to identify preferred options the SOs identified objective criteria and a scoring methodology both of which are outlined in this document. In choosing preferred options the SOs have had to balance the respective requirements of the various stakeholders involved in the project. The SOs believe that overall social welfare is best supported through a methodology which drives the efficient use and development of the transmission system.

In considering the various tariff options and the long term developmental needs of the transmission systems, the SOs believe that locational signals are a necessity and have attempted to balance the cost reflectivity inherent in such models with the requirements of user stakeholders. Therefore, the preferred tariff option has both a socialised postage stamp element and a dynamic locational signal which balances the need for efficiency with the need for stability over time. The System Operators have considered the level of the TUoS threshold for units connected to the distribution system and believe it reasonable to amend this to a lower level of 5MW. The current 10MW threshold was selected historically when relatively few small[1] distribution generators were connected to the transmission network. The number of distribution generators has increased dramatically in the last years, which has an impact on the transmission system.

The identification of a single preferred losses option was a more complex matter. The project team carried out research into alternative methodologies within a tight timescale. A number of options were analysed all of which are included in this document. Given the feedback from the industry and the considerable quantitative analysis carried out by the team, the SOs believe that the best way forward is a three step strategy: In the short term the SOs believe that the shortcomings of the current methodology should be addressed by way of a compression factor to limit the degree of volatility risk. In the medium term the SOs believe that work should be completed to research and potentially develop a splitting approach whereby a uniform loss factor is applied in the market with measures taken by the SOs Operations groups to ensure efficient dispatch. There are a number of implementation options to be investigated including whether to use an alternative loss optimized dispatch scheduling aid or integrated Marginal TLAFs in the dispatch

[1]In this paper " Small" refers to a unit with Maximum export capacity of less than 10MW

scheduling engines, and how and when to apportion losses and additional constraint costs between users of the system. The move to such a methodology would involve considerable change in three main areas: policy, market and technology. The move away from the current arrangements may involve changes to overall policy with implications which are outside the scope of this project. This is mainly the responsibility of the RAs. The project team will continue to examine these implications during the next phase of the project. The impact on the market needs to be studied, while the technical developments required to implement the splitting concept and the consequences of such changes need to be investigated by the SOs. In the long term, the SOs believe that the option of Purchase of Losses should be examined as a means both of accurately measuring total losses and of incentivising the SOs to reduce losses over the longer period.

Finally, SOs believe that a locational signal should be maintained and that any changes to the current methodologies will result in winners and losers. As a consequence, it is important that a number of complex competing factors be considered when choosing a particular direction to go. In weighing up such matters, the decision will rest with the RAs as to whether the overall social welfare of society is best served by the use of a particular locational signal method or a move away from locational signals in either tariffs or losses.

1. Background

This paper is a follow up to the Locational Signals Options paper which was published in May 2009 (SEM/09/060). The Options paper outlined a number of different tariff and losses methodologies being considered for use on the Island of Ireland from Q4 2010 onwards in order to provide locational signals to generators. These signals are both long and short term. In the long term the generators should be located to allow the network to develop in as efficient a manner as possible. In the short term the portfolio should be used as efficiently as possible to reduce the total costs to the system including losses etc. The provision of a distinct signal to demand users is not part of the scope of this document. However, the impact on demand users from any of the methodologies outlined in this paper has been considered.

There are a number of important historical factors which apply to the review of TUoS and losses arrangements on the island of Ireland. Firstly, there are different TUoS methodologies being used in each jurisdiction while the current losses approach is used on an all-island basis. Secondly, there are a number of extrinsic factors which may be significant in affecting the design of any methodology. These factors relate to the two transmission networks, the generation portfolio and the context in which the methodologies are applied.

Despite the changed circumstances brought about by the commencement of SEM, there is still a need to maintain a rigid link between specific locations and strategic investments to ensure that these investments occur in as efficient a manner as possible.

2. Introduction

Over the last few months, the SOs have completed several studies to determine which methodologies best suits the implementation of locational signals on the island of Ireland. A preferred option for both TUoS and losses is described in this document.

In addition to the high-level description of the tariff and losses methodologies, this document includes indicative tariffs for each methodology. Step by step flow charts for the operation of the preferred methodologies are also included.

Section 3 contains a description of the decision criteria and weightings which have been used to evaluate each tariff and losses option. The choice of criteria and weighting reflects input from the RAs, SOs and wider industry which was given during two workshops, a questionnaire and a consultation process.

Section 4 introduces a number of additional consideration factors which have been taken into account when determining a preferred option.

Sections 5 and 6 give an overview of the losses and tariff options at a high level. This is supplied to enable the reader to put the evaluation in section 8 and the description of the preferred option in section 9 into context.

Section 7 gives an overview of the studies that were carried in order to support an evaluation process for each option.

A complete evaluation of the various options is included in section 8.

Section 9 describes the preferred options and outlines how they will be applied in an all-island context. This section addresses many of the implementation issues which were identified during the earlier phases of the project.

There are a number of steps (which are described in Section 10) that will have to be taken in order to implement the preferred options.

The appendices contain the indicative tariff and losses values which have been calculated for each option studied. Given the volume of work in preparing indicative numbers for six tariff options and four losses options, the project team used readily available network and cost files. Final tariffs under any of these approaches would of course be based on more up to date and accurate assumptions and input data. Notwithstanding this, the indicative values do give a fair representation of how tariffs and losses might appear if each methodology was applied. Note that there are no Supplier/Demand tariffs included in this paper. A decision was taken by the RAs which precluded the project team from producing Supplier/Demand tariffs. As an alternative, the project team monitored the implications of particular Generation Tariff methodologies for Supplier/Demand users.

3. Decision Criteria

A description of the methodologies' objectives is given below. Based on feedback from various stakeholders which requested that these objectives be ranked, the SOs are therefore proposing weightings to evaluate each option. These reflect the relative importance placed on each objective by a combination of industry, regulatory and SO input. A full evaluation of each option using the objective criteria below is included in Section 8.

3.1. Objectives

1. Efficiency: To encourage efficient use of the network and efficient investment in infrastructure in the long term. This means making decisions that take into account the total cost to the network and infrastructure. This is of interest to all stakeholders as it addresses the long term sustainability of the system;
2. Transparency: The provision of information and models to ensure full transparency of all methodologies. The publication of indicative tariffs and losses for a number of years;
3. Predictability: The methodologies should enable the prediction of tariffs and losses to within a reasonable level. This predictability should be for a number of years, however it would not extend to the full investment horizon;
4. Volatility: Where possible the methodologies should avoid dramatic year on year fluctuations, so as to give contradictory signals;
5. Short term efficient dispatch (applies to losses methodologies): Any losses method should ensure that the dispatch is as efficient as possible including efficient use of energy and minimization of unnecessary dispatches. In order to achieve this objective, it will be necessary to study the effectiveness of any proposal in line with suggestions from the wider industry; and
6. Cost Reflectivity: Any tariff methodology & losses methodology should be cost reflective in order to provide the correct economic signals and to facilitate competition.

In addition to the six objectives outlined above, all tariff and losses methodologies should seek to recover the allowed TUoS revenue and forecast quantity of losses. This is possible through the application of a scaling factor, which can either be additive or multiplicative, at the end of the tariff or loss calculation methodology. When allocating losses, it may be considered desirable in the short term to override this objective when allocating losses as the advantages of a particular approach which does not allocate forecast losses could be deemed to outweigh the disadvantages.

3.2. Objective Weightings

3.2.1. Weightings for tariffs

Objectives	**weighting factor**
Efficiency	0.30
Cost Reflectivity	0.30
Volatility	0.20
Predictability	0.15
Transparency	0.05

Table 1: criteria weightings for tariffs

In choosing an option the weightings above outline the relevant importance of each of the objectives for an effective tariff design. One of the key elements of a tariff option is that it should drive efficiency. This efficiency revolves around the use of the network by generators through their locational decision and thus supporting efficient investment solutions in the development of the network.

A cost reflective tariff will differentiate between participants' impact on the network. Therefore, participants will face the costs of their behaviour and decisions. This will assist them in making efficient decisions which is to the benefit of all. Cost reflective tariffs shall also include a fair allocation mechanism for common costs.

Both the volatility and predictability criteria are closely linked. It can be argued that the main purpose of these particular objectives is to reduce uncertainty. This reduction in uncertainty will again assist efficiency (over the long term in particular). It will be easier to devise efficient solutions if there are fewer uncertain variables under consideration.

If a tariff is predictable then the issue of it changing (i.e. volatility) becomes less relevant as long as you can predict the change. However, if something is volatile it may be harder to predict. A predictable tariff removes uncertainty. Similarly it can be argued that a low volatile tariff will also have low uncertainty. Even if a tariff is predictable it is important that the volatility of the tariff does not send contradictory signals from year to year.

It must be noted that some methodologies have the potential to be more transparent than others. Measures will be taken with any option chosen to make it transparent. See Section 9.3.

Overall, the project team believes that direct economic factors are more significant than the non-economic factors. As a result the split of the weightings, as shown in table 1 above, between direct economic and non-economic factors is 60/40.

3.2.2. Weightings for losses

Objectives	**Weighting**
Efficient Dispatch	.25
Efficiency	.20
Cost Reflectivity	.20
Volatility	.15
Predictability	.15
Transparency	.05

Table 2: criteria weighting for losses

The weightings for losses have a slightly different relevance than for tariffs. The allocation of a losses methodology should ultimately strive to obtain an efficient dispatch of generators in the network. It is important to emphasise the difference between Efficient Dispatch and Efficiency. A system which is efficiently designed but without an efficient dispatch is of little value. An efficient dispatch of generators will ultimately lead to the reduction of overall transmission losses on the system. Efficient dispatch is the most important objective in relation to losses and is weighted accordingly.

It is vital that a losses methodology also drives efficiency – both in terms of running an efficient transmission network and in terms of sending a strong locational signal to prospective investors to ensure that they locate future generators in well reinforced areas of the grid. Some generators are responsible for proportionally more transmission losses than others depending on their point of connection to the grid. For this reason, TLAFs are site specific. TLAFs therefore not only support efficient real-time dispatch of the system but also help to promote the efficient location of generating plant. Efficiency will lead to the long term minimisation of transmission losses, the best possible use of the transmission network and therefore the lowest costs, and this is beneficial to society as a whole.

A losses methodology should be cost reflective. Cost reflectivity is another one of the key principles associated with the treatment of losses. Cost reflectivity and Efficiency are weighted equally in relation to their importance. With a cost reflective methodology the costs of losses are allocated to the individual market participants who cause them. If a generator is incurring losses then it should be penalised for those losses and this penalty should be reasonable and in proportion to the costs involved. If a generator is producing electricity against the dominant flow and thereby offsetting losses, then it should benefit. Cross-subsidisation is important also under the cost reflectivity criterion – a generator offsetting losses should not be penalised because a number of other generators are incurring losses. Similarly a generator incurring losses should not be benefiting from other generators offsetting losses. If the losses methodology is cost reflective, it will accurately differentiate between participant’s effects on the system. Participants will make efficient decisions based on these effects and this should ultimately benefit the All-Island Transmission System.

Similar to tariffs, the volatility and predictability criteria are closely linked in relation to a losses methodology. A losses methodology that is driven by a locational signal, by nature, may be volatile. It may be sensitive to the amount and type of generation in a given location. However, this sensitivity is desirable in terms of an efficient short term dispatch. If a location is seen as desirable for development of generation in one particular year but then experiences an influx of generation, it may no longer send a positive locational signal. It is now contributing to the system losses as opposed to off-setting them. To ensure short term efficient dispatch and cost reflectivity, it is intuitive that the losses methodology should be responsive and sensitive to new generation developments. On the other hand the trade-off between volatility and encouragement of future investment in the network is important to recognise. A losses methodology should be responsive while still encouraging investment and development. A methodology which is too volatile could increase the cost of capital for a potential investor and deflect efficient grid development.

Predictability was mentioned in the responses to the May Consultation and it has been decided to include it as a criterion in the assessment of a potential losses methodology. A predictable methodology may negate the negative aspects of the above volatility and contribute to encouraging efficient investment. The predictability reduces the uncertainty surrounding the volatility. There are 2 types of predictability accounted for in this paper. Extrinsic predictability looks at how factors outside the methodology itself affect it. Intrinsic predictability examines how predictable the components of the calculation of the losses methodology are.

Transparency is an important objective in relation to a losses methodology. It is beneficial to industry participants to be able to see that the losses are calculated accurately and are non-discriminatory. Participants may also wish to generate future projections of the loss factors. If the methodology is transparent, it will lend itself to facilitating future indicative calculations.

Finally, the split between direct economic and non-economic factors (65/35) reflects the relative significance placed on each group of factors by the project team.

4. Consideration Factors

In addition to the objectives outlined in the last section there are a number of major consideration factors which apply to **all** methodologies examined during the project.

4.1. Context

There are a number of boundary conditions or limiting factors, which have a significant impact on whether a particular approach would work on the Island of Ireland context including the following:

1. It is assumed that in general the Market Design Parameters will not radically change;
2. It is also assumed that the High-Level Design Paper from 2005 which references locational charges is still relevant. Note that certain options were considered even though their implementation would require changes to the SEM High-Level Design in the long term;
3. There will be a shallow connection charging policy;
4. Any arrangement will comply with national and EU legislation;
5. The arrangements will allow for changes in revenue size;
6. It must be feasible to implement all proposals in both jurisdictions; and
7. The arrangements must be consistent with other polices and practices within the market and within both jurisdictions, (e.g. connection charging policy, firm/non-firm access arrangements, etc…)

4.2. Economic Considerations: Treatment of Losses

This section discusses the economic theory supporting the choice of options for the treatment of losses, as presented in Section 5 of this paper. As previously mentioned, one of the primary objectives of the treatment of losses is that the methodology should promote short-term economic efficiency in the operation of the transmission system. This short-term efficiency should lead to the situation whereby dispatch is modified to reflect the cost of losses to the system.

The modified dispatch of units should ultimately result in a reduction in fuel costs, given that in cases where two economically equal generators located on different sites can both serve a particular node, the one whose location incurs a lower volume of losses, will be the unit dispatched. When fewer losses are incurred on the system, less energy has to be produced to satisfy demand. This, in theory, should provide a signal for generation to site closer to demand and depending on whether losses are allocated to suppliers also, a signal for demand to locate closer to generation. It is possible that the allocation of losses could provide a longer-term signal for units in their choice of location.

The question arises as to how losses on the system are best reflected. Understandably, losses change depending on the operating conditions at any time on the system. There is a need to balance the stability and predictability of the losses signal with the need for the losses to be cost reflective. The SOs are also conscious that the benefits of any losses allocation mechanism should outweigh the cost of implementing and applying the mechanism. A number of alternative treatments of losses are discussed later in this document.

4.3. Economic Considerations: Treatment of TUoS

Given that one of the principal objectives of network pricing is to send signals to users of the network regarding the costs they impose on network development, it is important that network planning and network pricing are consistent. This can be achieved by identifying key drivers associated with network development and corresponding investment costs. Through an efficient pricing method, users of the network need to be informed about their impact on network development costs which are the outcome of network planning exercises, hence the close link between network planning and pricing. When analyzing alternative options, consideration was given to the extent by which a particular network pricing methodology is consistent with network planning and that it captures the impact of key network planning principles on network cost (such as peak security and economic efficiency based planning).

4.4. Revenue Reconciliation

An economically optimal transmission network pricing methodology may not meet revenue adequacy constraints and some level of revenue reconciliation may be an important and inescapable aspect of transmission pricing. The main reasons which make it difficult to optimize networks are: lumpiness of transmission investment, economies of scale, standardization of overhead line and cable conductor sizes, uncertainties in generation and the need to recover certain cost elements associated with the operation and management of transmission systems, independent of network capacity. When conducting revenue reconciliation, the target is generally to achieve approved revenue targets with as little impact as possible on economic signals. Some general methodologies for solving this problem, such as Ramsey pricing[2], are discussed in economic literature[3].One of the issues associated with such methods is the tendency to increase charges to those users who are least sensitive to price, in order to achieve revenue targets. Another approach is to use scaling factors (multiplicative or additive) to adjust the charges to meet revenue requirements. In order to maintain the locational price differential, evaluated through marginal investment costs, the shortfall (residual) is recovered through imposing additional non-locational charges (which can be energy or peak

[2] For any monopoly, the price markup should be inverse to the price elasticity of demand: the more elastic demand for the product, the smaller the price markup.

[3] F. Ramsey, "A Contribution to the Theory of Taxation", Economic Journal, 37, March 1927, 47-61.
R.B. Wilson, "Nonlinear Pricing", Oxford University Press, 1993.
S. Stoft, "Power System Economics, Designing Markets for Electricity", The Institute of Electrical and Electronics Engineers, 2002.

based). Revenue adjustment techniques are discussed later in section 6.1.4 of this document.

4.5. Legacy Issues

There are a number of legacy issues that exist in both jurisdictions, which, while not boundary conditions, still need to be taken into account and possibly reviewed when devising new arrangements. Examples of these include:

1. The transition from deep connection charging policy to shallow connection charging in Northern Ireland. Users that connected in NI prior to the establishment of the SEM paid for deep reinforcements however users in ROI paid only for shallow connection charges while the additional deep reinforcement costs are recovered via TUoS revenue;
2. All embedded generators connected in ROI before 19th of February 2000 have a TLAF of 1 as directed by CER;
3. Wind generators and any temporary generator connected to the system have a lower tariff limit of zero which means that these units cannot have a negative tariff and hence cannot receive TUoS payments; and
4. The tariff methodology adopted must allow for any arrangements that exist to facilitate non-firm access to the system;

4.6. Feedback from Industry

There were 15 responses to the Options paper which was published in May 2009. While some of the comments focused exclusively on individual positions, there were a number of common themes that were expressed in the feedback:

1. Other locational signals apart from TUoS and TLAF are important such as Firm/non-firm access.

   a. There are a number of locational signals including shallow charges which were outside of the scope of this document which were described by participants as being significantly important;
2. The existing TLAF signals can be volatile and therefore a number of respondents believe that the signals can be misleading.
   a. As part of the review the SOs carried out a number of studies in which it was evident that TLAFs have changed considerably in a number of locations. This is generally related to the amount of generation concentrated in a particular location;
   b. Volatility has been ranked as an important objective of the proposed new approach for the treatment of losses.
3. The threshold for paying TUoS needs to be reviewed.
   a. Section 6.1.8 outlines proposed changes to the threshold for distribution connected generators.
4. The location of wind projects away from areas of demand and the appropriateness of continued use of the current losses methodology to discriminate against them.
   a. The current losses methodology reflects the underlying losses associated with particular locations;
5. Given the scale of the current connection queue in the Republic of Ireland alone, many of the wider industry believe that the Gate approach (Gate 2 and 3) should be taken into consideration when designing tariffs.
   a. It is important to note that any methodology for tariffs will apply equally to all generators which include those generators not covered by the Gated process ;
6. A number of respondents from the generation industry believe that losses should be paid by the demand participants as losses are passed through by generators in any event
   a. See the comment below in point 7;
7. Demand respondents believe that as generators are better placed to position themselves with favourable losses in mind, they should pay 100% of losses

   a. The participants' comments in this section and in section above are from opposing viewpoints. Therefore the SOs approached the issue in a manner which is fair to all parties;

8. A number of respondents stated that load-flow based methodologies lack transparency.
   a. The number of measures to ensure that there is adequate transparency are outlined in Section 8.3 as part of the description of the preferred option; and
9. A number of respondents indicated their concerns that locational tariffs and losses are not predictable by industry groups.
   a. In response to this the SOs are committed to producing indicative tariffs and losses for future years to improve the predictability of these;
10. In relation to the treatment of TUoS tariffs a considerable number of respondents indicated their preference for the Postage Stamp plus incentive discount.
    a. The SOs directed much time and effort to investigating this option with a view to implementation but unfortunately it was not feasible, the reasons are discussed in more detail in section 6.7.2.
11. A number of respondents believed the SOs should be incentivised to reduce losses and that the purchase of losses approach should be implemented.
    a. The SOs have given considerable thought to this and a long-term option involving the purchase of losses has been proposed by the SOs as outlined in section 9.2.3.

5. Losses Options

This section presents four alternative losses methodologies which were evaluated for use on the island of Ireland. The four options are as follows:

1. Loss Adjustment Factors (6.1)[4]
2. Uniform Loss Adjustment Factors (6.2)
3. Zonal Loss Adjustment factors (6.3)
4. Purchase of Losses (6.4)

5.1. Overview

Each of these 4 options has individual effects on the Single Electricity Market in relation to:

- Impact on SMP
- Changes in Marginal Plant
- Changes to In-Merit Plant in the Market Schedule
- Changes in Volume of Losses Incurred
- Changes to Bid Prices and Infra-Marginal Rent
- Changes in Constraints Payments
- Changes in Capacity Payments
- Changes in Imperfections Charges faced by suppliers
- Changes in Reserve

The consequences of any of the above options are difficult to quantify – cause and effect are difficult to determine. There are a number of other more substantial variables than Loss Factors involved, which impact the above, including:

- Fuel Prices
- Carbon Prices
- Seasonal Variations

[4] Please note that the referenced number refers to identification of the options as outlined in SEM/09/060.

- Changes in Demand Profile
- Generation Availability

For instance, it is difficult to say what effect alternative losses methodologies have on the SMP. The majority of higher prices occur during periods of high demand and the majority of lower prices occur during periods of low demand. However, while the Average Demand Weighted SMP for Q4 2008 was €77.07/MWh the Shadow Price (which is a component of the SMP) was reduced to €0/MWh at one point in this quarter due to high amount of wind on the system and all conventional generators being ramped back to their Minimum Stable Generation. Furthermore, in the same quarter in 2008, the Uplift component brought the SMP to its maximum value of the year (€690/MWh) when a time-constrained generator fell out of the merit order and had to recover all its un-recouped start-up costs in a short period of time.[5] Add on the variability of Gas and Carbon prices to these examples and it is clear that it is very difficult to quantify the effect of one variable on the SMP at any given trading period. Changes in other variables may obscure the impact from one specific variable.

5.2. Loss Adjustment Factors

Transmission Loss Adjustment Factors, which are calculated using Marginal Loss Factors (MLFs), are derived for each generator, taking account of forecast assumptions of average system demand, average generation dispatch, time of the year (month) and day (daytime and night-time). This approach is used in both jurisdictions on the Island of Ireland. For a particular load and generation dispatch scenario, the MLF of a generator can be defined as the ratio of the change in system demand to the change in generation of the generator.

EirGrid and SONI's current approach to TLAF derivation involves the use of power flow modelling software for marginal loss studies for each generator in the Single

[5] For further information see SEM Market Monitoring Unit – Public Report 2009 (SEM/09/039)

Electricity Market (SEM) accessing the market. EirGrid and SONI develop a number of study cases that represent real system conditions and dispatch.

The losses allocated by MLFs are higher than base-case (or average) losses. This results in a requirement for scaling of marginal loss factors to ensure that only the base-case losses, as determined by separate studies in our power flow modelling software, are allocated to users. The MLFs derived for each generator are scaled uniformly using a shift [delta], or subtractive, approach so that the apportionment (generator output multiplied by the loss factor) meets the base-case losses. This is performed for each applicable case (i.e. day and night for each month). The overall loss allocation for each representative case (losses multiplied by case hours) is summed to determine whether the total allocated losses meet the forecast of overall system losses for the year. These factors are then scaled again using the shift method; to ensure the final apportionment (forecast generator output multiplied by the TLAFs) exactly recovers the annual forecast of transmission system losses.

It has been highlighted by industry participants that TLAFs are too volatile resulting in large revenue swings year on year which has an impact on the finance of new generation. The project team therefore examined ways to improve the current methodology to dampen the volatility without eliminating an efficiency signal.

The following options dampen both the volatility and the short term efficient dispatch of the current losses methodology. If the methodology becomes more inefficient, increased costs will be incurred on the system. It is likely that the demand side will pick up the costs of the inefficiency.

5.2.1. Update on TLAFs - Rolling Average

The first measure considered to reduce volatility was a simple rolling average. By averaging over 3 years it is possible to smooth some of the larger TLAF fluctuations which have been observed in the past. The study in Appendix A describes the implementation, study method, criteria addressed and issues that arise due to the method.

To simply illustrate the Rolling Average Methodology take an arbitrary Thermal Plant called Thermal 1. Thermal 1's Actual TLAFs for the 3-year period 07-09 alongside the 2009 3-Year Rolling Average are shown below:

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sept		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
2007	0.98	0.991	0.98	0.991	0.97	0.984	0.97	0.984	0.97	0.984	0.98	0.992	0.98	0.992	0.98	0.992	0.97	0.985	0.97	0.985	0.978	1.001	0.977	0.998
2008	0.984	0.995	0.981	0.994	0.981	0.992	0.980	0.988	0.981	0.990	0.974	0.987	0.974	0.987	0.978	0.988	0.978	0.989	0.983	0.995	0.985	0.995	0.984	0.997
2009	0.980	0.988	0.977	0.987	0.980	0.988	0.980	0.987	0.991	0.997	0.981	0.991	0.984	0.991	0.983	0.989	0.987	0.993	0.997	1.009	0.993	1.003	0.993	0.999
							Rolling Average 2009																	
	0.981	**0.991**	**0.979**	**0.991**	**0.978**	**0.988**	**0.977**	**0.986**	**0.981**	**0.990**	**0.977**	**0.990**	**0.978**	**0.990**	**0.979**	**0.990**	**0.978**	**0.989**	**0.983**	**0.996**	**0.985**	**1.000**	**0.985**	**0.998**

Table 3: Rolling average TLAFs for "Thermal 1"

- 07-9 TLAF data for Thermal 1 displays the following data:
  Max – 1.009
  Min – 0.969

- 2009 Rolling Average Data for Thermal 1:
  Max – 1.000
  Min – 0.977

The main advantage of the method is the reduction in the effects of volatility, its simplicity and transparency. Its principle disadvantages are the impact on efficiency, cost reflectivity and the fact that new and legacy participants would be treated differently. The full study is included in Appendix A.

5.2.2. Update on TLAFs - Banding

The second option explored by the Project team to improve on the current methodology was the use of fixed bands. With this approach the TLAF was calculated as before however a further step was added. Each value is normalised to fall into one of 5 different bands (0.96, 0.98, 1.0, 1.02 and 1.04). The bands were arbitrarily selected and could be changed pending further consultation. A full outline of the actual study is included in Appendix B. The main advantage of the approach is that it reduces volatility and increases predictability. The concept is relatively straight-forward to implement.

There are a number of disadvantages with the approach: it reduces the efficiency of the dispatch in the short term. It also reduces the cost reflectivity of the losses methodology. The relative ranking between participants is removed in many cases. It is possible that the losses are not fully recovered. Generators incurring losses on the system are not fully penalised and generators offsetting losses do not receive full benefits. The Banded TLAF method does not have a huge impact on multiple year TLAF variability as this is ultimately affected by the introduction and removal of generation and demand. However, it does reduce the negative or positive effects of such changes.

An edging effect is created using this method. A slight change in a participant's underlying TLAF may lead them to jumping from one band to another. For example, in year 1 a generator has a TLAF of 0.967 and therefore is allocated a Banding TLAF of 0.98. In year 2 their underlying TLAF changes to 0.958 and the generator is allocated a Banding TLAF of 0.96. One can see that a minor change can lead to a large divergence in what Banding TLAF is applied.

To illustrate the methodology a random wind generator was chosen from the All-Island list of participants, 'Wind 1'. The tables below show 09 TLAF data compared against the new Banded TLAF and 08 TLAF data compared against the new Banded TLAF.

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sept		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
2009	1.026	1.018	1.026	1.023	1.021	1.021	1.033	1.021	1.014	1.007	1.025	1.001	1.013	0.992	1.012	0.993	0.992	0.973	0.976	0.947	0.973	0.953	0.976	0.963
Banded	**1.02**	**1**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1**	**1**	**1.02**	**1**	**1**	**1**	**1**	**1**	**1**	**0.98**	**0.98**	**0.96**	**0.98**	**0.96**	**0.98**	**0.98**
2008	0.998	1.008	1.002	1.012	1.011	1.020	1.021	1.032	1.040	1.038	1.052	1.033	1.048	1.028	1.031	1.029	1.032	1.024	1.015	1.004	1.004	1.008	1.008	1.023
Banded	**1**	**1**	**1**	**1**	**1**	**1.02**	**1.02**	**1.02**	**1.04**	**1.02**	**1.04**	**1.02**	**1.04**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1**	**1**	**1**	**1**	**1**	**1.02**

Table 4: Banded TLAFs for "Wind 1"

09 TLAF for 'Wind 1':
Max: 1.033
Min: 0.947

09 Banded TLAF:
Max: 1.02
Min: 0.96

08 TLAF for 'Wind 1':
Max: 1.052
Min: 0.998

08 Banded TLAF:
Max: 1.04
Min: 1

The TLAF for this particular Wind Generator is very volatile moving from 1.052 to 0.947 over 2 years. The banding reduces the effect of that volatility somewhat. However, there is still considerable jumping between bands and cost reflectivity and efficient dispatch is obviously reduced.

Implementation of the Banding Methodology will be beneficial for market participants currently being allocated low TLAFs. However, participants with high TLAFs currently and potentially low generation outputs will see a reduction in profits as a result of their loss adjustment factor being banded at a maximum of 1.04.

As stated previously, the full outline of the study is included in Appendix B.

5.2.3. Update on TLAFs - Compression

The third option for reducing the impact of volatility in TLAFs involves the use of an algorithm to compress the TLAF. Assuming that the initial TLAF falls within the range of 0.90 and 1.10, then the compression factor works to retain the relative order, while ensuring that limits are applied to minimum and maximum factors allocated.

The approach has a number of advantages. The algorithm is self – limiting. It naturally selects its minimum and maximum limits based on 2 factors:

- an initial TLAF range of between 0.9 and 1.1[6].
- the algorithm normalisation number (see Appendix C for more details). Assuming the algorithm is normalised around 1[7] the minimum and maximum limits will become 0.95 and 1.05.

The final figure retains a locational signal and is still cost reflective albeit at a reduced level. The TLAF becomes more predictable and consistent and the effects of volatility on the TLAF are reduced by approximately 50%. These limits applied by the algorithm should increase overall efficiency by reducing investment risks and, as a result, reduce the cost of capital for a generator. The Compression Factor would provide an encouraging signal to future generation to locate in efficient areas of the network and thereby ensure long-term security of supply.

The approach also has a number of negatives. There is a reduction in efficient short term dispatch under this methodology. The algorithm is arbitrary but the fraction chosen is reasonable based on the study of alternatives which yield lower overall limits and the need for more rounding of figures. It is possible that the losses are not fully recovered. Generators incurring losses on the system are not fully penalised and generators offsetting losses do not receive full benefits e.g. a generator allocated a TLAF of 0.90 could be increased to 0.95[8]. The generator would still be ranked appropriately in the merit order, however, it would not be fully charged for the losses being incurred on the system as a result of its location. Market participants with low TLAFs currently will benefit from this methodology. However, there would be negative implications for generators with very high TLAFs

[6] As per historical published data TLAFs have not fallen outside of this range.
[7] Subject to change pending further consultation.
[8] Note that these figures are based on the algorithm being normalized around 1, it's possible that the algorithm could be normalized around another figure.

who may only export on an occasional basis. Further study is required to determine the full effects of this methodology on the Market and Dispatch Schedules and also on the full recovery of losses.

To illustrate this example a random wind generator was chosen from the All-Island list of participants, 'Wind 2'. The tables below show 09 TLAF data compared against the new Compression Factor[9] and 08 TLAF data compared against the new Compression Factor.

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sept		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
2009	1.026	1.018	1.026	1.023	1.021	1.021	1.033	1.021	1.014	1.007	1.025	1.001	1.013	0.992	1.012	0.993	0.992	0.973	0.976	0.947	0.973	0.953	0.976	0.963
Compression	1.013	1.009	1.013	1.012	1.011	1.011	1.017	1.011	1.007	1.004	1.013	1.001	1.007	0.996	1.006	0.997	0.996	0.987	0.988	0.974	0.987	0.977	0.988	0.982
2008	0.998	1.008	1.002	1.012	1.011	1.020	1.021	1.032	1.040	1.038	1.052	1.033	1.048	1.028	1.031	1.029	1.032	1.024	1.015	1.004	1.004	1.008	1.008	1.023
Compression	0.999	1.004	1.001	1.006	1.006	1.010	1.011	1.016	1.020	1.019	1.026	1.017	1.024	1.014	1.016	1.015	1.016	1.012	1.008	1.002	1.002	1.004	1.004	1.012

Table 5: Compression Factors for "Wind 2"

09 TLAF for 'Wind 2':
Max: 1.033
Min: 0.947

09 Compression Factor:
Max: 1.017
Min: 0.974

08 TLAF for 'Wind 2':
Max: 1.052
Min: 0.998

08 Compression Factor:
Max: 1.026
Min: 0.999

Under the regular TLAF the range between Min and Max is 0.105 (1.052 – 0.947). Under the Compression Factor the range between Min and Max is 0.052 (1.026 – 0.974). The range is reduced here by approximately 50%. This equates to a reduction in the effects of volatility by approximately 50%.

[9] Note again that all these figures are based on the algorithm being normalized around 1 – it is possible that the algorithm will be normalized around another figure.

5.2.4. Update on TLAFs – 4 Methodology Comparison

Selecting a random generator, "Wind 3" – based on the 2009 and 2008 TLAF there is a comparison below of the actual TLAF against the 3 TLAF Updates – Banding, Compression and Rolling Average:

	Month																										
	January		February		March		April		May		June		July		August		September		October		November		December				
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Min	Max	Range
2009																											
Regular TLAF	0.975	0.953	0.989	0.957	0.982	0.957	0.972	0.958	0.959	0.930	0.959	0.934	0.976	0.942	0.978	0.940	0.983	0.947	0.974	0.941	0.978	0.945	0.975	0.957	0.930	0.989	0.059
Rolling Average	0.985	0.939	0.992	0.949	0.975	0.947	0.973	0.953	0.972	0.940	0.968	0.935	0.972	0.938	0.975	0.938	0.975	0.938	0.968	0.936	0.975	0.947	0.970	0.945	0.935	0.992	0.047
Banding	0.98	0.96	1	0.96	1	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.960	1.000	0.04
Compression	0.988	0.977	0.995	0.979	0.991	0.979	0.986	0.979	0.980	0.965	0.980	0.967	0.988	0.971	0.989	0.970	0.992	0.974	0.987	0.971	0.989	0.973	0.988	0.979	0.965	0.995	0.03
2008																											
Regular TLAF	0.971	0.922	0.976	0.949	0.956	0.932	0.958	0.949	0.970	0.938	0.970	0.932	0.967	0.932	0.974	0.933	0.970	0.932	0.959	0.933	0.967	0.940	0.957	0.924	0.922	0.976	0.054
Rolling Average	1.006	0.945	1.007	0.954	0.979	0.948	0.980	0.953	0.984	0.950	0.982	0.939	0.981	0.939	0.984	0.940	0.976	0.938	0.972	0.939	0.978	0.949	0.974	0.943	0.938	1.007	0.069
Banding	0.98	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.98	0.96	0.96	0.96	0.960	0.980	0.020
Compression	0.9855	0.961	0.988	0.9745	0.978	0.966	0.979	0.9745	0.985	0.969	0.985	0.966	0.9835	0.966	0.987	0.9665	0.985	0.966	0.9795	0.9665	0.9835	0.97	0.9785	0.962	0.961	0.988	0.027

Table 6: Comparison of TLAF methodologies

Selecting a random thermal generator, based on the 2009 and 2008 TLAF there is a comparison below of the actual TLAF against the 3 TLAF Updates – Banding, Compression and Rolling Average:

	Month																										
	January		February		March		April		May		June		July		August		September		October		November		December				
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Min	Max	Range
2009																											
Regular TLAF	0.986	0.994	0.984	0.994	0.986	0.995	0.985	0.992	0.996	1.002	0.986	0.995	0.988	0.994	0.988	0.994	0.990	0.996	0.998	1.008	0.996	1.005	0.997	1.001	0.984	1.008	0.024
Rolling Average	0.983	0.994	0.982	0.993	0.980	0.991	0.979	0.989	0.983	0.993	0.981	0.993	0.982	0.993	0.983	0.994	0.983	0.993	0.987	0.999	0.990	1.003	0.990	1.001	0.979	1.003	0.024
Banding	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000
Compression	0.993	0.997	0.992	0.997	0.993	0.998	0.993	0.996	0.998	1.001	0.993	0.998	0.994	0.997	0.994	0.997	0.995	0.998	0.999	1.004	0.998	1.003	0.9985	1.001	0.992	1.004	0.012
2008																											
Regular TLAF	0.984	0.996	0.982	0.995	0.982	0.993	0.980	0.989	0.981	0.991	0.982	0.992	0.982	0.993	0.986	0.996	0.985	0.995	0.990	1.001	0.992	1.000	0.990	1.001	0.980	1.001	0.021
Rolling Average	0.993	0.997	0.992	0.997	0.993	0.998	0.993	0.996	0.998	1.001	0.993	0.998	0.994	0.997	0.994	0.997	0.995	0.998	0.999	1.004	0.998	1.003	0.999	1.001	0.992	1.004	0.012
Banding	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1.000	1.000	0.000
Compression	0.992	0.998	0.991	0.9975	0.991	0.997	0.99	0.9945	0.991	0.996	0.991	0.996	0.991	0.997	0.993	0.998	0.993	0.998	0.995	1.0005	0.996	1	0.995	1.001	0.990	1.001	0.011

Table 7: Comparison of TLAF methodologies on Thermal Generator near a large demand centre

5.3. Uniform Loss Adjustment Factors

An alternative to providing a nodal loss factor is to use uniform loss adjustment factors. Using uniform loss adjustment factors results in one TLAF being allocated to every participant. This methodology has a number of advantages. The TLAF would be non-volatile, predictable and transparent.

The strongest disadvantage associated with this method is the locational signal is removed from both the market and short term dispatch. Dispatch is now less efficient and the consumer potentially covers the costs of these inefficiencies. Individual participant's specific impact on losses is not reflected and so the method is not cost reflective. Therefore, uniform losses send a lacklustre signal in terms of the impact that participants have on the system. There is also the issue that cross subsidisation occurs in that a generator off-setting losses could find itself paying extra for a generating unit increasing the overall losses on the system. A uniform loss adjustment approach would not be compatible with the June 2005 SEM High-Level Design.
Finally, the ramifications of this method will significantly impact a number of key areas;

- SMP
- Infra-marginal rent
- Error Supplier Unit
- Economic Signals

Please refer to section 9.2.2. for further details of these implications.

The two options for the implementation of Uniform Loss Adjustment Factors are described below:

5.3.1. Pure Uniform Loss Adjustment Factors

Under this method the transmission losses that exist in the network system are allocated on a socialised basis. Individual participant's specific impact on losses is not reflected and so the method is not cost reflective. Rather it is the aggregate impact of all participants that is reflected. Therefore, uniform losses send a lacklustre signal in terms of the impact that participants have on the system. Furthermore, considering dispatch, the use of one TLAF for every participant will not lead to an efficient dispatch in terms of losses. Uniform losses essentially remove the variable impact that TLAFs can be considered to introduce for individual participants and between participants. The changes in the total network losses would be reflected in the uniform TLAF. With the aggregate nature of the uniform TLAF the variability would be expected to be minimal. The TLAF would be consistent, predictable and transparent. A uniform loss factor does not send either a short term or long term transmission locational signal to participants regarding the losses associated with their location. There is also the issue that cross subsidisation could occur in that a generator off-setting losses could find itself paying extra for a generating unit increasing the overall losses on the system. The lack of signal regarding losses may result in reducing the efficiency of the short term dispatch. This reduction will increase the overall losses on the system. As a result the uniform loss factor will deteriorate. Finally, a uniform loss adjustment approach would not be compatible with the June 2005 SEM High-Level Design.

5.3.2. Splitting methodology

During the analysis of the Uniform Loss Adjustment Factor option an additional concept was devised that would complement and reduce the negative aspects of the introduction of a uniform loss factor. This concept has been characterised as 'splitting'. The splitting concept involves separating the locational signal and cost recovery for losses from the market and developing a new method to try and achieve a short term efficient dispatch in the physical dispatch software. In other words, removing the locational signal for losses from the market, introducing a uniform loss factor and modifying the systems which run the physical dispatch. Alternative means, which are not incorporated in the market, should be devised to charge locationally for the losses e.g. through an additional component in the TUoS charge. This option is appropriate to implement in the medium term.

For further detail please refer to the preferred loss option section 9.2.2.

5.4. Zonal Losses Adjustment Factors

A further option is to allocate losses on a zonal basis. Zonal transmission loss factors are derived from dispatch and system modelling, similar to the current TLAF approach. Participants within the same zone receive the same loss factor. The intention of zonal transmission losses is to attempt to send long-term transmission locational signals regarding losses. It has the potential to send significant information to users regarding the implications associated with locating in a certain area and to support a reduction in the total amount of electricity transmitted and therefore increase the efficient use of energy. Its signal has the possible potential to be relatively consistent over time because it is incorporating an aggregate number of nodal loss factors into one loss factor.

While a zonal loss factor does not reflect the losses from specific nodal locations it is more reflective than uniform losses. In terms of efficient dispatch and other considerations (see objectives), there is a trade-off to be made between the costs and benefits of nodal loss factors and uniform losses which needs to be managed. It is in the management of this trade-off where zonal losses may prove to be an appropriate solution. A further important decision that needs to be considered regarding zonal losses is determining the area that the zones cover. This requires extensive and comprehensive analysis. The areas selected and the impact of such a selection will feed into the management of the above mentioned trade-off.

5.4.1. Update on Zonal Loss Factors

A study was carried out on Zonal Losses Adjustment Factors which is outlined in Appendix D. While there are a number of advantages with the approach the study identified a number of issues, which the project team believe preclude its further development as a viable option.

Firstly, it is very difficult to provide rationale for defining different zones. For the current study the zones used were pre-defined by internal planning software. The criteria for zone selection could be very subjective. Time constraints really dictated the selection of the zones – as the island was already divided into zones for internal planning analyses, it was agreed to use the same zones for the purposes of the current study. Again, the zones could be subject to change pending consultation, but it is important to use the current zones in order to illustrate the principle of the methodology. Secondly, as the zones cover large areas, the process itself of averaging, reduces the locational signal. Lastly, as the zonal TLAF is the average of a group of generators in a zone, efficiency of the dispatch would be reduced, cost reflectivity would be reduced and the losses may not be fully recovered.

To illustrate this methodology, a random wind generator was chosen from Area 4. Area 4 consists of a number of generators as defined by internal planning software. It is possible for the zone selection to change with further consultation but applying the principle of Zonal Adjustment Factors to the defined Area 4 on a random Wind Generator, 'Wind 4', the figures are as follows:

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sept		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
2009	1.032	1.023	1.034	1.029	1.028	1.027	1.040	1.027	1.023	1.014	1.029	1.009	1.029	1.007	1.029	1.007	1.017	0.993	1.002	0.977	1.001	0.981	1.003	0.988
Zonal Average	**0.999**	**1.001**	**0.998**	**1.005**	**0.994**	**1.002**	**1.006**	**1.003**	**0.996**	**0.996**	**0.999**	**0.993**	**1.002**	**0.994**	**1.002**	**0.993**	**0.994**	**0.985**	**0.983**	**0.975**	**0.982**	**0.977**	**0.982**	**0.979**

Table 8: Zonal TLAFs for "Area 4 Wind 4"

09 TLAF for 'Wind 4':
Max: 1.040
Min: 0.977

09 Zonal:
Max: 1.006
Min: 0.975

As is illustrated here, there is only a slight reduction in volatility and the Min allocated TLAF has been reduced for the particular Wind Generator studied. As mentioned above the zone average is being selected for 'Wind 4' and so the locational signal and hence efficient short term dispatch and cost reflectivity is being reduced greatly.

5.5. Purchase of Losses

Losses result in a misalignment in the market between what has been produced by generators and what is being consumed by demand. One method of overcoming this misalignment is for the TSO to purchase these losses. In other words, the TSO buys at the system marginal price the unit (MW) gap between what has been produced and consumed. This is a long term option and due to the infrastructural changes required cannot be implemented in the short term. Refer to Section 9.2.3 for a more detailed explanation of Purchase of Losses.

6. Tariff Options

This section presents the six alternative potential tariff methodologies which were presented in section 7 of the Options paper. The RA's felt it more appropriate at this stage to focus on potential generator tariffs under each of these models therefore supplier tariffs are not contained in this paper. A review of Supplier TUOS tariffs shall be undertaken as a separate process. Details and timeframes for the current review of the NI Supplier TUoS tariff methodology can be found on NIAUR website. Each option is accompanied by a discussion regarding the analysis undertaken since the May 2009 Option Consultation paper (SEM/09/060).

The six options as outlined in the May 2009 paper are as follows:

- Option 1: Pure transmission locational signaling Static Model (7.1.1)[10];
- Option 2: Pure transmission locational signaling Dynamic Model (7.1.2);
- Option 3: Transmission locational signalling Static Model with Postage Stamp("delta") (7.2.1);
- Option 4: Transmission locational signalling Dynamic Model with Postage Stamp ("delta")(7.2.2);
- Option 5: Postage Stamp model (7.3.1);
- Option 6: Postage Stamp with Incentive Discount model (7.3.2)

Going forward in this document the SOs shall refer to each of the tariff models as Option 1 to Option 6 to correspond with the numbers shown above, for example the Pure transmission locational signaling static model which is referred to as model 7.1.1 in the May 09 options paper will be called "Option 1" and the Postage stamp model 7.3.1 shall be referred to as "Option 5".

6.1. Overview

There are number of common elements that relate to the TUoS options. These are outlined below. The primary features of each of the locational tariff models are summarised in the table below.

[10] Please note that the referenced number refers to identification of the options as outlined in SEM/09/060.

Option	Reference Number	Locational	Network studied	Asset Costs applied	Adjustment method (residual)
1	7.1.1	Yes	Static	Average	Multiplier
2	7.1.2	Yes	Dynamic	Average	Multiplier
3	7.2.1	Yes	Static	Marginal	Delta
4	7.2.2	Yes	Dynamic	Average	Delta
5	7.3.1	No	N/A	N/A	N/A
6	7.3.2	No	N/A	N/A	N/A

Table 9: primary features of each tariff option

Glossary of features for tariff model options	
Static Network	A network based on the existing all-island network in place today
Dynamic Network	A network in the future which includes planned network reinforcement required to meet expected forecasts of generation and demand. Costs are only associated with future assets, and from 2010 onwards, assets less than 7 years old.
Average costs	Actual modern equivalent asset values
Marginal costs	Cost associated only with lines and cable
Multiplier	A scaling mechanism which multiplies each tariff value by the same proportion to ensure correct revenue recovery
Delta	A scaling mechanism that adds or subtracts an uniform absolute value from each tariff value to ensure correct revenue recovery. Sometimes referred to as "Postage stamp"

Table 10: Glossary of main TUoS model features

6.1.1. Load Flow Analysis

Options 1 to 4 above are locational tariff methodologies and therefore require load flow analysis to be performed to assess the use of the network by each generator unit. Various methods can be used to conduct the load flow analysis, for the purposes of the indicative tariffs presented in this document the Reverse MW Mile methodology has been adopted for models 1 to 4 above. Further details on this methodology can be found in the Options paper published in May 2009.

In order to conduct any load flow, assumptions are required with regard to the level and location of generation and demand. For the purposes of the indicative tariffs, input files depicting the network which had been prepared in 2008 for both 2008/2009 tariff year and 2013/2014 tariff year were applied. The demand and generation assumptions in these models are consistent with the most recent estimates contained in SONI's NI Seven year Transmission statement and EirGrid's Transmission Forecast statement. The 2013/2014 input files take account of new investments which are expected to be complete by this time. It also accounts for any units which are expected to connect to or retire from the network. Obviously any extreme deviations from these assumption may cause a significant impact on the resulting tariffs, however the SOs believe the demand and generation assumptions applied for both periods are appropriate for deriving indicative tariffs.

6.1.2. Scenarios

It is very important that network pricing and network planning policies are consistent. Therefore, locational tariff methodologies should consider all potential scenarios which give rise to network investment planning. For this reason the indicative tariffs for the locational models (Options 1 to 4 above) have been based on four network development scenarios which are commonly used by those responsible for planning the network. The four scenarios are: Winter Peak with zero wind generation assumed, Summer Peak with zero wind generation assumed, Summer Peak with wind generators dispatched at 80% of their installed capacity and Summer Minimum with wind generators also dispatched at 80% of installed capacity.

The choice of these dispatch scenarios has been based on previous experience of the actual scenarios that have driven network investment. If tariffs were based on only one possible scenario such as Winter peak, then units who drive investment of the network at Winter peak would have higher costs and other units, who might drive investment at other times, such as Summer Peak, would not be charged for their contribution towards additional network investment requirements. Only by examining all the various possible situations that drive network investment will the resulting tariffs be cost reflective of actual network planning. Appendix O sets outs further details and examples of recent investments under each of the scenarios. In time, as more and more wind generation connects to the system the scenarios may need to be modified to account for the increased wind and to ensure that the scenarios are still relevant and remain consistent with Planning criteria. The SOs intend to review the four scenarios periodically to ensure these remain consistent with network planning policy in NI and ROI. In future any proposed changes to the scenarios would of course be communicated to industry groups beforehand.

For each of the four scenarios generation is dispatched to meet the forecast level of demand using a merit-order dispatch derived from Plexos[11]. A tariff is derived for every unit under each of the four scenarios, to assess the use of the network that each unit makes in each scenario. Obviously not every unit would normally be dispatched in each scenario therefore in the situation that a particular unit is not expected to be dispatched in a scenario then a tariff is calculated by dispatching each of these units one-by-one at 1MW in order to determine a tariff for the unit. Once a tariff has been calculated for each unit in each of the four scenarios then the maximum tariff is identified for each generator unit. If this maximum tariff was applied the model would not recover exactly the required revenue hence the maximum tariff is scaled for each unit to produce a final tariff. The scaling approach used is either a multiplier or a “Delta” as appropriate - this is discussed in more detail in section **Error! Reference source not found.**. Two units connected to

[11] Plexos is the model used to forecast market outcomes in the SEM

the same node would both have the same TUoS tariff applied, no account is taken of generation type.

An alternative to the above approach would be to use software which would enable the maximum flow on each individual circuit from the four scenarios to be identified. The cost for each circuit would then be charged to only those units using it in the scenario with the highest flow i.e. the scenario that drives investment for that circuit. For the purposes of these indicative tariffs it was not feasible to implement this software, so the maximum tariff was applied as this is deemed to be a reasonable proxy for such an approach. However it would be possible to employ this specialised software, if deemed appropriate, once the final tariff methodology is selected.

6.1.3. Average costs and Marginal costs

As outlined later in the detailed description of each tariff option some models incorporate average or actual costs of assets and some models are based on the marginal costs.

For clarity, average costs are based on costs associated with recent builds and therefore are assumed to be estimates of actual costs. Both SOs apply standard average costs, such as the cost for a typical km of 110 Overhead line, as opposed to specific costs for every individual circuit, which would be labour intensive to implement. Average costs are the total costs including station costs. The average cost values applied in the indicative tariffs are the standard assets costs that have approved by each RA for that jurisdiction.

Marginal costs are applied in England, Scotland & Wales for transmission tariffs (TNUoS). Marginal costs are primarily concerned with identifying the cost that an additional 1MW of generation imposes on the network and hence relate only to the additional length of cable of overhead line that would be required to facilitate the additional MW. In the marginal cost model examined in Option 3, marginal costs include the standard costs of overhead line and cable only, no station costs are included. Both marginal costs and average costs are based on the MEAV (Modern Equivalent Asset Value).

A Static model has been used with both average and marginal costs. Research indicates that the Dynamic model is more compatible with average costs and therefore both models incorporating a Dynamic network (options 2 and 4) employ average costs.

Once the average or marginal capital cost for each circuit has been determined the costs are converted into annualised costs. These annualised costs account for the approved rate of return on the assets as well as depreciation and operation and maintenance.

6.1.4. Delta and Multiplier (Scaling techniques)

In each of the models the exact required revenue will not be recovered therefore an adjustment must be made. In previous years the RAs and SOs have discussed the merits of using either a multiplier adjustment, which scales each tariff by the same percentage, or an absolute adjustment, known as a "Delta." A multiplier adjustment maintains the locational signals provided by the model by scaling each final tariff by the same relative proportion. The "Delta" adjustment is an additive or subtractive and does not allocate the over or under recovery on a locational basis. In the tariff model options currently examined the SOs have used both methods of adjustment in order to fully assess the implications of each. As shown in table 8 above, two static models are examined, Option 1 with multiplier and Option 3 with delta and similarly two dynamic models, one with each type of adjustment, Option 2 with multiplier and Option 4 with delta As illustrated in the indicative tariffs in Appendix K, the effect of using a multiplier rather than a delta can be significant to an individual generator. As the criteria weightings illustrate, it is not simply a question of whether a multiplier is better than a delta or vice versa, it is a question of which works best with the chosen model to deliver the overall objectives of the tariff methodology. Each of the models using multiplier and delta have been weighted against the criteria so that the combined model, including the adjustment method, that more fully delivers the overall objectives of the tariff methodology can be identified.

6.1.5. Treatment of Wind

As outlined in Section 4.5 of this document, currently wind generators are not attributed a negative tariff. Wind generators and any temporary generator connected to the system have a lower tariff limit of zero which means that these units cannot have a negative tariff and hence cannot receive TUoS payments. The SOs felt however that it would be more worthwhile to publish the indicative tariff calculated under each methodology without adjusting the necessary tariffs so as to provide wind generators with an indication of the final tariffs under each methodology for comparative purposes. Final tariff in October 2010 shall be adjusted so as to maintain a lower tariff threshold of zero for wind generators and temporary generators.

All tariffs options examined as part of this process have been done so in a manner that does not differentiate between type of generation. Conventional and non-conventional generation are examined to assess their impact on the existing network or future network, as relevant. Other than the application of a lower threshold for wind generators no further differentiation is made. The transmission network is designed and must be built to deliver the required capacity for each new unit with firm capacity, irrespective of the characteristics of that unit. As mentioned in section **Error! Reference source not found.**, charging for units with non-firm access to the transmission system shall be addressed separately, once the charging methodology for firm access is chosen.

6.1.6. TUoS Revenue Requirement from Generator Charges

For the purposes of all indicative tariffs an annual revenue requirement of €57m was assumed. This amount is comparable with the actual all island revenue requirement for 2008/2009 as approved by NIAUR and CER for each jurisdiction.

6.1.7. Capacity based Charges

The indicative tariffs which have been calculated under all of the tariff methodologies above have been done on the basis of capacity based charging. This was done because capacity is a key driver for designing the network when a connection is being analysed. It is envisaged that each unit would pay the relevant TUoS charge based on its contracted Maximum Export Capacity (MEC) as set out in the relevant Connection Agreement or TUoS Agreement.

6.1.8. Charging Threshold for Distribution connected generators

Currently, both in ROI and NI, generators which are connected to the distribution system and have a contracted export capacity of less than 10MW have been charged a zero rate of TUoS. As part of the current review process a number of industry groups have requested that the System Operators reduce this threshold.

The System Operators have considered the level of the TUoS threshold for units connected to the distribution system and believe it reasonable to amend this to a lower level of 5MW. The current 10MW threshold was selected historically when relatively few small[12] distribution generators were connected to networks. The combined impact of these small generators on exporting power onto the transmission system was minimal then. These small generators were mainly supplying local distribution system load and hence were not required to contribute towards transmission costs.

Government policies to reduce CO_2 emissions have lead to UK and Irish government renewable energy targets of 15% and 16% respectively by 2020. In recent years many new connections have been provided for small generators to connect to the distribution system, in particular wind farms. The aggregate effect of these small generators exporting onto the transmission system is believed to have a significant impact and one which is growing year on year. The transmission system has to be designed and built to facilitate the increased generation exported from the distribution connected generators onto the transmission system from distribution nodes that are often located in remote western areas. It seems reasonable to amend the threshold for TUoS charges to 5MW to account for the changes in topology and use of the NI and ROI transmission networks. All units with contracted maximum export capacity (MEC) of 5MW and above should be charged the appropriate rate of TUoS as approved by NIAUR and CER and published by SONI and EirGrid.

In addition to lowering the TUoS charging threshold, a further amendment is suggested in relation to how the threshold shall be applied. This change has been made in response to

[12]In this paper “ Small” refers to a unit with Maximum export capacity of less than 10MW

industry feedback[13]. Currently generators with MEC equal to or above the threshold pay TUoS on the full amount of their MEC. This creates a level of capacity where the generator can see a substantial step increase if it was to increases it export capacity, say from 9MW to 10MW. In order to address this issue and avoid a level of contracted capacity with a substantial step increase in TUoS charges, the System Operators propose to only apply TUoS charges to distribution connected generators for capacity in excess of the 5MW threshold. So, for example, a unit with a contracted capacity of 6 MW will only pay TUoS based on 1MW and a unit with a contracted capacity of 10MW will only pay TUoS based on 5MW, whereas before the 10MW unit would have been charged TUoS for the full 10MW of capacity.

The rationale for not charging distribution connected for the first 5 MW of their capacity (i.e. 5MW less than their contracted MEC) is that it is assumed up to 5MW of the output from each unit will be absorbed by demand connected to the local distribution system and that the remainder of the output will be exported on to the transmission system and use transmission assets.

All generators connected to the transmission system will continue to pay TUoS based on the full amount of their contracted export capacity. This reflects the use these units make of the transmission system given that transmission connected units output all generation directly onto the transmission system.

6.1.9. Charging arrangements for non-firm transmission system access

It should be noted that this document does not address the issue of charging for units with non-firm access to the transmission system. It is important that the charging methodology chosen can facilitate charging for non-firm access to the system. It is envisaged that once a decision has been made on the tariff model to be implemented the SOs will give consideration to the non-firm charging issue.

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[13] IWEA response in July 2008 consultation "The current proposal charges generators over 10MW for all of their capacity while distribution connected generators under 10MW are exempt. Thus creates a significant step effect in charges for generators just over 10MW. The IWEA recommends that generators should be charged on the basis of capacity above 10MW only".

6.1.10. Indicative tariffs

Indicative tariffs have been calculated for options 1 to 5 above and these are set out in the appendices. It should be noted that these tariffs are indicative only and have been derived using existing data files for 2008/2009 and 2013/2014 that had previously been prepared by both SOs. In the timeframe it was not possible to derive updated input files to be used for each tariff methodology. The indicative 2008/2009 tariffs should not be used as an estimate of 2010/2011 tariffs. Actual tariffs to be implemented in 2010/2011 under the chosen methodology will be derived using updated input data, including updated forecasts of demand and generation, updated estimates of merit order dispatch and updated values for asset costs.

In the following section each potential tariff option shall be described and analysed. An assessment of the positive and negative factors associated with each option shall be outlined along with the SOs recommendation for an option to be implemented from October 2010.

6.2. Option 1: Pure transmission locational signalling Static Model(7.1.1[14]*)*

6.2.1. Description

Two options were suggested for undertaking a locational signal methodology using a Static model, this option and Option 3, a Static Model with Postage Stamp. Both Static models require the development of a fixed network. A Static model examines the cost of the entire network that all network users in aggregate will require. For the purposes of deriving the indicative tariffs the Static network is based on today's existing network and uses the Modern Equivalent Asset Value (MEAV) technique to value the network.

Normally when locational tariffs are derived these will not always match the revenue requirements in any particular tariff period, therefore some form of a residual element must be applied to scale tariffs up or down as relevant. There are two main types of

[14] Reference from May 29th Options Paper

residual adjustments that can be applied, one is a multiplier, whereby each units tariff is multiplied up or down by the same factor to achieve the required revenue. The second type of residual is a postage stamp or "delta" residual. The delta can be described as a uniform €/kW/year amount that is added or subtracted to each tariff to ensure adequate revenue recovery in the tariff period. Option 1 uses a multiplier adjustment to correct the revenue recovery.

In addition Option 1 also applies average asset costs in the recovery calculation, similar to the current locational methodology applied in ROI. The Static model is centred on a fixed development setting for the network. Participants are charged for the cost of this network based on their long term requirement for network capacity. This is approximately reflected through the user's contribution to the critical power flows.

6.2.2. Indicative tariffs & Analysis

Please refer to Appendices J and K for details of generator's individual indicative tariffs for 2008/2009 and 2103/2014 using option 1 approach. The indicative tariffs illustrated have been adjusted to ensure the collection of only the revenue requirement.

Indicative tariffs for 2013/2014 have also been calculated using Option 1. Volatility analysis for both option 1 and option 3 (Static models) are outlined in Appendix N.

6.2.3. Assessment

The Static model approach signals cost-reflectivity regarding the use of the current network. Participants are charged in direct proportion to their use of the existing network assets. As a result participants that use lines that are expensive will contribute towards this higher cost. The participants are receiving the benefits of the more expensive lines and both this option and option 3 ensure that they contribute more for these benefits. This model however does not signal the cost of future reinforcements nor does it provide any incentive to reduce the need for future investment in the network. One drawback of this methodology is that it will charge a generator for using assets which are already built and which have available capacity in the same way as it would charge for a similar new asset which has to be built specifically for that new generator, to this extent the model can lead to some inefficiencies. As outlined in "Transmission pricing methodology"[15] published by Fronstep economics "With respect to the existing network increased usages involves little additional cost, as most costs are sunk, therefore static efficiency requires that prices for the existing network should seek to recover the regulated revenue in a manner that does not discourage network usage. However, where investment in the transmission system is required the incremental costs of additional usage are much higher." In the Static model no differentiation is made between sunk assets and new assets therefore the model does not achieve the static efficiency that is desirable.

In addition, this option has the potential to prove rather volatile for individual participants. Network developments and changes in the generation and demand patterns change how power flows circulate across the network which means that tariffs can vary significantly from year to year for participants. This potential volatility may make it more difficult to predict the value of future tariffs. As illustrate in Appendix K the indicative tariffs for this model in 2008/2009 have a substantially higher range of values than that produced when the Dynamic model option 2 is applied. Figure 10 in Appendix N outlines the indicative tariffs in 2008/2009 and 2013/2014 derived using this model; it is evident that for a number of units the tariff can be particularly volatile under this approach.

In deriving 2014 indicative tariff the same revenue requirement as 2008/2009 was assumed to allow comparison of the two sets of tariffs on a like for like basis.

6.2.4. Conclusions

In conclusion, Option 1, given that it is a locational tariff methodology based on estimated usage of network assets, has the ability to provide cost reflective tariffs. This model however, does not promote maximum efficient investment in the network. In addition, the potential for volatility may negate the benefits of having this type of locational signal.

[15] Transmission pricing methodology, Options and guidelines, Published June 2004 by Fronstep economics

6.3 Option 2: Pure transmission locational signalling Dynamic Model (7.1.2[16])

6.3.1 Description

Presently a locational tariff methodology is applied to generator TUoS charges in ROI which incorporates a Static model, such as that described above in section **Error! Reference source not found.**. In previous years proposed all island locational tariff models were also based on a similar Static network. As part of the current review process the System Operators have examined two tariff options which are based on what is known as a "Dynamic" network model. This Dynamic model is concerned with applying costs to those who drive the need for future investment on the transmission network. The rationale for using a Dynamic network model as opposed to a Static model is that we cannot change decisions that have been already taken, we can only influence future decision, therefore the model applied should be forward looking and attempt to signal efficient future network developments rather than apportioning costs based on usage of existing assets.

This type of Dynamic model has been applied elsewhere and is due to be implemented in 2010 in England, Scotland & Wales for distribution network charges.

In the Dynamic model we examine the future network and how it shall be used by existing generation to satisfy existing levels of demand based on a merit-order dispatch of existing generation. The Dynamic model provides both an entry and exit signal to generators. The aggregate effect of all generation is examined; therefore an existing unit which combined with a new unit brings about the need for future reinforcement will pay for these future costs. In the case that the new unit did not connect then the future investment may not be required but similarly if the existing unit was to leave the network, the new unit may be able to connect without the reinforcements. The two units combined bring about the need for new investment and hence both shall contribute to these costs. The existing unit however, contributes earlier given that the new unit cannot be charged until it has

[16] Reference from May 29th Options Paper

connected to the network. Continuing to charge for assets for a period after these have been built will ensure that the new unit does contribute once it has connected.

The May 2009 Options paper (SEM/09/060) outlined two locational tariff options that incorporate the Dynamic model concept. Under these options the locational charges reflect the Net Present Value (NPV) of costs associated with future network reinforcements required as a consequence of a forecasted generation and demand load growth during a chosen time horizon. The Dynamic model utilises standard asset costs of the network assets. Participants are sent a signal today regarding their contribution in driving the need for future network developments. Cost as allocated in a dynamic model as follows:

1. Future network requirements are identified;
2. The year when these are required is calculated;
3. The cost of the assets in that year is determined;
4. The costs are converted in to today's value (net present value) using the appropriate discount rate;
5. Generators who are deemed from load flow analysis to use the future assets are charged for these, based on their usage. For example a unit that uses 50% of the total capacity of a new circuit would pay 50% of the annuitised valued of this asset (assuming that the unit is not reversing flows);
6. Spare capacity on any asset is not charged to a specific unit – it is recovered in the residual component of the charge; and
7. Assets built from 2010 onwards which are less than seven years will also have costs associated with them.

The NPV of a future asset is higher as we come closer to the year it is required, so for example a 10 Km length of overhead line required in 5 years time will have a lower NPV than a similar 10km of over head line required in one year's time (assuming that there is inflation).

It is anticipated that from Oct 2010 charging for future network developments will continue for a period of seven years after the asset has been built[17]. This avoids a free-rider problem whereby if assets are costed at zero from when they are built participants could connect after the asset has been built in order to avoid contributing towards the cost of the asset. So any assets that are complete and added to the regulated asset base on Jan 2011 will be included in the dynamic model with a MEAV cost until 2018.

The amount recovered by this approach is dependent on the level of future network developments. Unlike the static models the dynamic model will have a tendency to under-recover and hence require tariffs to be scaled upwards using a residual element. Again, either a multiplier or delta will be used to adjust the individual tariffs to ensure revenue reconciliation. The type of the residual applied is the only aspect which separates the two Dynamic model options. For clarity, this option uses a multiplier while option 4 uses a "delta" or postage stamp residual.

In the May 09 Consultation Options paper (SEM/09/060) it was suggested that an explicit head room concept would determine when future network needs would be identified. However, in order to ensure consistency with Grid 25 it is now proposed that the Grid 25 plans will be used to determine the timing of future network developments as well as the NI seven year transmission statement. This assists in ensuring that participants will be charged for developments that are planned to be actually built.

The main requirement for the Dynamic model is to have forecasted future generation and evolving demand growth, this then determines what will be built in the years to come under the chosen time horizon. These required assets can then be valued at their NPV. It is crucial that there is consistency in what the model includes for network development and what is determined by the network planners e.g. Grid 25. This will be ensured through the model's use of the same data sources regarding the future developments. The model will be consistent with and will reflect actual future network plans.

[17] The SOs shall keep this asset recovery period under review and if appropriate shall recommend modification

6.3.2 Indicative tariffs & Analysis

Please refer to the appendix J for details of generator's individual indicative tariffs for 2008/2009. The time horizon for the Dynamic model was 5 years i.e. up to and including 2014. In these indicative tariffs, all assets built by 2008 have been allocated a zero cost and only costs of future assets are considered. As explained above it would be the SOs intention to continue to recover the cost of new assets for a number of years after these are built to ensure that new units also pay towards these assets. It was not possible to calculate the indicative tariffs on this basis in the timeframe. If this particular approach was adapted, the time horizon could be subject to change if deemed appropriate. This new time horizon would then be used in the application of the model. The Dynamic models use standard asset costs and both recovered approximately 35% of the required revenue before any adjustments were undertaken to ensure revenue reconciliation. In this instance, the use of Multiplier leads to this option having a much broader range of divergence between participants.

6.3.3 Assessment

As this approach charges participants for future network investments it can be considered efficient in sending appropriate signals regarding future network investments. It is focused on actual forward looking costs and not sunk costs which cannot be altered. Participants that are driving the need for these developments and that will benefit from them are contributing towards the cost of the developments. Therefore, it is also cost reflective. The model encourages efficient use of the network, a unit which uses an existing asset already paid for will not pay for doing so whereas a users that brings about the need for new assets to be built will pay higher TUoS charges to contribute towards the cost of these.

Network developments are lumpy in nature and therefore some years will have more developments than others. This may increase the yearly volatility in tariffs for participants. However, this potential difficulty may be partially negated by the fact that the assets will be included for seven years after they are built. This may well assist in levelling out any volatility. The tariffs should be more predictable than with a Static model because there will be details published of what will be built in the forthcoming years e.g. Forecast Statement/ Transmission Seven Year Statement. This will indicate how the tariffs could change over the years. The issue of changes in the power flows, as mentioned in the static model, still exists but given that this model only applies costs to generators using future assets and those built in the previous seven years the impact of changing patterns of flows might be less than with the Static models

The current indicative tariff for generators is based on the period up to 2014. However, with a different time horizon the tariff may change. Significant network developments are planned over the coming years and therefore the timing of the horizon can have a large impact on the tariffs. The ramp up in investment will lead to the dynamic model collecting more of the revenue requirement and this may magnify the impact of this potential volatility.

Using a Dynamic model with a multiplier adjustment to recover required revenue can have considerable drawbacks, for example, if a diminutive level of future investments is required in the specific timeframe the burden of transmission tariffs can fall on a very small number of generators who are driving the future investment. In the extreme case this could result in zero tariffs for almost all generators and extremely large tariffs for other units. The range of tariff values from this revenue reconciliation approach can be significantly higher than with other options.

6.3.4 Conclusion

This dynamic model derives tariffs that promote efficient use of the network and efficient investment in the network. Resulting tariffs are also cost-reflective.

As mentioned above however, there is the risk of volatility with this methodology and the extent of this depends on the specific timeframe and planned investments. Of all four locational tariff methodologies this has the risk of being the most volatile as well as producing an extremely large variation in tariffs for each unit. For these reasons the SOs are not recommending that this option 2 model is implemented in Q4 2010.

6.4 Option 3: Transmission locational signalling marginal cost Static Model with Postage Stamp (7.2.1[18])

6.4.1 Description

Like option 1 described above this model is based on the current all-island network and using the same four scenarios to derive a tariff for each generator. Again applying the maximum tariff from the four scenarios to each unit will not match the revenue requirements in any particular tariff period, therefore a residual element must be applied to scale tariffs up or down as relevant. In this model the "delta" which can be described as a uniform €/kW/year amount that is added or subtracted to each tariff to ensure adequate revenue recovery in the tariff period.

One further difference between this option and option 1 is that this model, similar to model applied in England Scotland & Wales, is based on marginal costs.

6.4.2 Indicative tariffs & Analysis

Please refer to Appendices J and K for details of generator's individual indicative tariffs for 2008/9 and 2013/2014 using this model approach. As expected this model also results in an over recovery of the revenue requirement and therefore the tariffs have been adjusted to ensure the collection of only the revenue requirement.

From the statistics illustrated in Appendix K it is clear that this option 3 leads to more extreme results. The use of a considerable delta adjustment in this model results in a significant divergence in tariffs between participants which the high range illustrates. The high standard deviation of calculated tariffs indicates that there is a large spread of tariff values from the mean. Volatility analysis for this model is also outlined in Appendix N, Figure 11 shows the change in tariff for each unit which is present on the system in both years. While the volatility might look somewhat similar to that in option 1 it is worth noting the scale of the axis for the two charts are not identical, the axis for this model are illustrating a much larger range of tariff values.

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[18] Reference from May 29th Options Paper

6.4.3 Assessment

As with option 1, this static model approach also signals cost-reflectivity regarding the use of the current network. Participants are charged in direct proportion to their use of the existing network assets. However as discussed in section **Error! Reference source not found.** above, the Static model given neither differentiates between new and existing assets nor incentivises efficient investment in the network in the way that a model such as the Dynamic model can.

This model approach with a large non locational residual element has the potential to prove volatile for individual participants and probably more volatile than option 1 given the large "Delta" adjustment which is applied. Network developments and changes in the generation and demand patterns change how power flows circulate across the network which means that tariffs could vary from year to year for participants. Again this potential volatility may make it more difficult to predict the value of future tariffs.

Finally, the magnitude of the large adjustment required in this type of model is also capable of significantly distorting the locational signals that the methodology attempts to send.

6.4.4 Conclusions

In conclusion, this model, given that it is a locational tariff methodology based on estimated usage of network assets, has the ability to provide cost reflective tariffs. However, the large non-locational residual element that needs to be applied to ensure correct revenue recovery dilutes the cost-reflectivity and hence the locational signals. Again this model does not promote maximum efficient investment in the network. In addition, the application of the non-locational residual to scale the revenue recovery to match exact revenue requirements has the potential to create an extremely large range of tariffs, the highest of all four locational options examined, which are spread very far from the mean tariff value. This large adjustment can also distort the intended locational signal. The potential for volatility is again a serious consideration in relation to this model. For all of these reasons the SOs do not recommend this tariff option for implementation.

6.5 Option 4: Pure transmission locational signalling Dynamic Model with Postage Stamp(7.2.2[19])

6.5.1 Description

As we can see from table 3 above this option has the same model features as Option 2 except for the adjustment method applied to ensure adequate revenue recovery. For clarity, Option 2 described in section **Error! Reference source not found.** above utilises a multiplier while this model applies a "delta" or postage stamp residual.

As outlined above the Dynamic model reflects the Net Present Value (NPV) of costs associated with future network reinforcements required as a consequence of a forecasted generation background and evolving demand load growth during a chosen time horizon. This model considers the aggregate effect that existing and new users have on the network. This Dynamic model also utilises actual costing of the network assets. Participants are sent a signal today regarding their contribution in driving the need for future network developments.

6.5.2 Indicative tariffs & Analysis

Please refer to the Appendix J for details of generator's individual indicative tariffs for 2008/2009. The time horizon for the Dynamic model was 5 years i.e. up to and including 2014. In these indicative tariffs all assets built by 2008 have been allocated a zero cost and only costs of future assets are considered. As explained above it is the SO's intention to continue to recover the cost of new assets for a period of 7 years after these are built to ensure that new units also pay towards these assets. It was not possible to calculate the indicative tariffs on this basis as we started at year 1. The adjustment using the delta results in this option having a lower standard deviation than option 2, hence the tariffs lie closer to the mean tariff value. The range of tariff values produced by this methodology is the lowest of all the methods examined and the spread of tariff values is closest to the mean value. Units located in areas where new investment is required have a higher tariff than units not driving any investment in the timeframe under examination. Closer analysis shows the different trends produced from this methodology to the one in **Error!**

[19] Reference from May 29th Options Paper

Reference source not found. whereby no Delta or postage stamp element is applied. Every unit in this methodology has a positive tariff because every unit contributes a fixed amount, which can be attributed to recovering the cost of sunk assets.

6.5.3 Assessment

Again, as this approach charges participants for future network investments, it can be considered efficient in sending appropriate signals regarding future network investments. It is focused on actual forward looking costs and not sunk costs which cannot be altered. Participants that are driving the need for these developments and that will benefit from them are contributing towards the cost of the developments. Therefore, it is also cost reflective. The model encourages efficient use of the network; a unit which uses an existing asset already paid for will not pay for doing so whereas a user that brings about the need for new assets to be built will pay higher TUoS charges to contribute towards the cost of these.

Network developments are lumpy in nature and therefore some years will have more developments than others. This may increase the yearly volatility in tariffs for participants. However, this potential difficulty may be partially negated by the fact that the assets will be included for seven years after they are built. This may well assist in levelling out any volatility. The tariffs are more predictable than those produced with a Static model because there will be details published of what will be built in the forthcoming years e.g. Forecast Statement/ Transmission Seven Year Statement. This will indicate how the tariffs could change over the years.

In addition, the SOs feel that it is appropriate to introduce a limitation in this model which will negate and reduce any potential volatility in tariffs from year to year. Significant network developments are planned over the coming years and therefore the timing of the horizon can have a large impact on the tariffs. The ramp up in investment will lead to the Dynamic locational element collecting more of the revenue requirement and this may magnify the impact of the potential volatility. In order to address any potential volatility concerns, the SOs recommend applying a limit to the locational element of the tariff. The locational element of the tariff would be limited to 60% of the overall revenue recovery which means than in any year a postage stamp tariffs will contribute a minimum of 40%

of the overall revenue recovery. This 60/40 split is consistent with the breakdown in criteria weightings of the tariff model and with the fact that it is appropriate to allocate a higher proportion on the need to incentivise the minimisation of future costs. As illustrated in table 1, the two economic factors contribute to 60% of the overall ranking of the model. 40% of the overall ranking is attributed to factors that are non-economic but that are nonetheless extremely important, particularly to industry groups. The locational element of the overall tariff will deliver the economic objectives such as efficiency and cost-reflectivity while the postage stamp component of the tariff will deliver the non-economic objectives such as volatility and predictability. In any year where the locational element of the tariffs recovers less than 60% of the revenue requirement, the postage stamp component will be in excess of 40%. This large postage stamp component should reduce volatility and improve predictability of this tariff methodology.

It was not necessary to introduce this limitation to the locational element of the tariff in the indicative tariffs given that the locational element only recovered approximately 35% of the total all-island generator revenue requirement. Establishing that the 60% limitation on the level of locational charges shall exist in future however, should allow all generators some degree of assurance that the tariff will not be capable of the type of fluctuations such as those associated with option 2.

6.5.4 Conclusions

This methodology delivers tariffs which meet the economic principles of efficiency and cost-reflectivity. The model is forward looking which is consistent with providing future siting signals. The method allows reasonable predictability given that high costs are associated with future investments and these are published by the SOs. There is potential for volatility due to the lumpy nature of network developments however as mentioned above, this should be significantly reduced by including a fixed postage stamp element. The range of tariff values and deviation of these is lowest of all four locational tariff model options. The SOs believe that this option best delivers the objectives of a tariff methodology. It addresses all the main concerns which have been raised by all stakeholders. This methodology allows the SOs to develop transmission tariffs that will facilitate competition in the all-island market.

6.6 Option 5: Postage Stamping Methodologies for Generator TUoS (7.3.1[20])

6.6.1 Description

The postage stamping methodology charges the same rate to every participant. Therefore, participants are charged a certain rate per MW of contracted export capacity on the same basis. It does not provide a transmission locational signal. In order to calculate the rate, the TUoS tariff revenue requirement is determined first. This is then divided by the total chargeable capacity of all units that are eligible for TUoS charges.

Furthermore, the rate charged to participants will directly increase or decrease with the revenue requirement and changes in forecast contracted export capacity values. The use of postage stamping technique results in smoothing out of changes in the revenue requirement across all participants. Every participant is affected in the same manner i.e. through the tariff rate.

The use of a Pure Postage Stamp approach would not be compatible or consistent with the June 2005 SEM High Level design as it stands now.

[20] Reference from May 29th Options Paper

6.6.2 Indicative tariffs

It was decided that the Postage Stamp option, like the locational methodologies would be based solely on capacity. The 2008/9 indicative tariffs are included in the Appendix J. As consistent with the methodology every participant receives the same charge per MW of MEC. Therefore, it is a very stable and consistent tariff. No further adjustments are required to ensure revenue reconciliation.

6.6.3 Assessment

Implementation of this option is non-complex. The revenue requirement is simply divided by the total contracted capacity of all units that are eligible for charges. The postage stamp option caters for concerns of volatility because the key factor is the revenue requirement. Furthermore, this leads it to being a more predictable TUoS option. However, it does not signal efficient use of the network or efficient investment in the network. This is because it does not differentiate between units. A unit that brings about the need for very large network reinforcements will pay the same TUoS charges as a unit which connected to the network with no additional costs to transmission users. Therefore, this lack of differentiation means that the option is not cost reflective. Other users which have had little or no impact on network costs will pay a proportion of the increased network costs that have been driven by other users.

6.6.4 Conclusion

This option is the most simple of all options to implement however it fails to send any locational signal to network users. The lack of cost reflectivity leads to cross-subsidising between participants, generators who drive no additional costs on the network will still pay higher TUoS charges to pay for the actions of other users who inflict additional transmission costs. The use of a Pure Postage Stamp approach would not be compatible or consistent with the June 2005 SEM High Level design as it stands now. Most importantly this option does not encourage efficient use of the network or efficient investment in the network. For these reasons the SOs are not recommending that this model is implemented in 2010.

6.7 Option 6: Postage Stamp Model with Discount (7.3.2[21])

6.7.1 Description

This option makes adjustments to the "Postage Stamp" option. While it is broadly similar it introduces an important concept. It offers the system operators the flexibility to provide a discount on the TUoS tariff to participants that locate in an area that is considered favourable to the performance of the transmission network. Therefore, this discount is in effect providing a transmission locational signal.

The postage stamp element is not providing a locational signal. It is allocating a set rate to every participant. This set rate can then be applied to participants on a capacity (MW), energy usage (MWh) or a combination basis.

Essentially the system operator selects a number of areas where the introduction of a generator or demand participant will improve performance of the network. This is done on an annual basis. The theory was that in order to determine favourable areas the SO would run studies for a given area that compares the introduction of a generator/demand participant to developing the network in terms of reliability standards and economic value. If the analysis determines that the introduction of a participant would bring net benefits (i.e. provides better value than developing the network) then an appropriate figure would be determined for the discount to incentivise the introduction of the participant. The upper boundary of this discount would be the value placed on the benefits that the participant would deliver. The availability of the discount would be limited to a certain capacity or energy level for a given area.

The participant will not know exactly what his charge will be going forward but it will have certainty that its charge will be lower compared to other units who have not chosen a "favourable" location.

[21] Reference from May 29th Options Paper

If, say, in another three years a second participant comes along and wishes to connect to that same location, the location may no longer be deemed as a "favourable" location, therefore no discount would be offered to the new generator. The new unit may however still decide to locate on the site, but he has the advance knowledge that his TUoS costs will be higher than if it was to select a different site which the TSO deems as favourable. The connection of an additional unit has no impact on the TUoS costs of the original unit who chose the location when it was a favourable location. The original unit will have a lower TUoS tariff than the new unit who has sited close by.

It was not possible to derive indicative tariff using this methodology given the difficulties discussed below.

6.7.2 Assessment

Considerable analysis was undertaken to determine the most effective incentive method. A number of different methods were evaluated and assessed. This included introducing a penalty incentive along side the discount. One approach was singled out as a possible means to determine favourable/unfavourable areas that the incentive could apply to, a valuation technique and a means to allocate the incentive to particular participants However, it was determined that this specific approach or the other approaches would not result in a effective executable incentive mechanism. The option has been rejected due to practical limitations. Some of the key difficulties are outlined below.

1. The incentive valuation technique would require extensive involvement from the Planning Departments. The additional analysis required to determine the favourable/unfavourable areas would introduce questions of consistency with other planning initiatives and analysis. Ensuring consistency in the analysis could be a particularly complicated and time consuming process.
2. The process to allocate the incentive to participants that would be connecting in favourable/unfavourable areas may not be practical to implement. The process was designed to be reasonable and clearly defined. However, real life events may raise dilemmas in the process that have the potential to be difficult to overcome.
3. The incentive may not be that effective and beneficial in the long term. Favourable/unfavourable areas are identified at the end of the time horizon when

generators are typically expected to connect. The incentive would apply for a period after the connection date e.g. seven years. However, the area may not remain favourable/unfavourable after the connection date. Therefore, the incentive may not be appropriate to apply. This is an inherent risk involved in basing an incentive on the expectation of what will occur in the future.

4. Under this approach cross-subsidisation would occur between participants.
5. In other countries extensive studies are carried out to determine the quantum or scale of saving involved with the location of generations at certain nodes. Despite the use of such studies the experience of other TSOs is that the discounted tariffs tend to be set using an arbitrary figure.
6. This method treats new and existing generators differently which industry groups did not express support for.
7. This methods increases risk for existing generators, as more new units connect in a deemed favourable area and receive a long-term discount, more revenue must be collected from existing generators to pay for the incentive discount given.

6.7.3 Conclusion

Unfortunately, this model at first seemed to be a suitable model to address the combined objectives of the all island tariff methodology. All stakeholders felt it potentially could satisfy the given objectives by delivering a cost-reflective signal in a manner that was not overly volatile. The SOs spent considerable time to define a mechanism that could be used to identify favourable areas in a transparent non-discriminatory way that would give industry sufficient time to react to the signal. It was also required that the model could facilitate a number of units seeking to connect to the network around the same time and take account of Gate 3 applications which are already submitted but not connected. Unfortunately, for the reasons discussed above, in practice this approach is difficult to implement without exposing current generators to an undesirable level of risk. The SOs do not feel it is appropriate to recommend this approach for implementation in Q4 2010.

7. Studies

Each option described in Sections 4 and 5 was applied to the all-island context in order to determine its suitability for application in 2010 and beyond. In all cases, a study or number of different studies were used to develop and analyse the relevant option.

For most methodologies the quantitative analysis involved the production of indicative numbers for one or more years. The tables below describe the work done on each methodology. The qualitative analysis involved attributing a score against the criteria which was described in Section 2.

Method	Indicative 2007/8/9	Special Study	Criteria Score
TLAF-Rolling Average	Appendix F	Appendix A	Section 8
TLAF-Banding	Appendix H	Appendix B	Section 8
TLAF-Compression	Appendix I	Appendix C	Section 8
Uniform	NA	NA	Section 8
Uniform + Splitting	NA	NA	Section 8
Zonal	Appendix G[22]	Appendix D	Section 8
Purchase of losses	NA	NA	Section 8

Table 11: table of losses studies

Method	Indicative 2008/9	Indicative 2013/2014	Criteria Score
Option 1	Appendix J	Appendix L	Section 8
Option 2	Appendix J	NA	Section 8
Option 3	Appendix J	Appendix L	Section 8
Option 4	Appendix J	NA	Section 8
Option 5	Appendix J	NA	Section 8
Option 6	NA	NA	Section 8

Table 12: table of tariff studies

[22] As there were relatively few generators in certain zones it was not viable to produce 2007 indicatives

8. Evaluation Options

8.1. Comparison of tariff Options

The table below outlines how the different tariff options were evaluated based on the criteria weighting as expressed in section 2.2.1.

		Tariff Option					
Objective	**Weighting**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**	**Option 6**
Efficiency	0.30	3	3	5	4	1	Na
Cost Reflectivity	0.30	3	2	5	5	1	Na
Volatility	0.20	2	2	1	3	5	Na
Predictability	0.15	2	2	3	4	5	Na
Transparency	0.05	1	1	1	3	5	Na
Total Score	**1.0**	**2.6**	**2.3**	**3.70**	**4.05**	**2.4**	**Na**

Table 13: comparison of TUoS options

8.1.1. Explanation of Scoring

In the table above each model has been scored against how it meets the objectives. A score of 1 is the lowest score and indicates that it is expected that this model option would not satisfy the given objective. A score of 5 is the maximum score and indicates that it is expected that this model would most likely satisfy the objective to a high degree. For example, option 5 is the simple postage stamp model, this scores 5, the maximum score for volatility, predictability and transparency as it is believed that this model more than any other would be least volatile, most predictable, to the extent that the tariffs can be predicted, and most transparent. This option scores 1, the lowest score possible, in terms of meeting the objectives of efficiency and cost-reflectivity as there is no mechanism in the model that would encourage any efficiency or cost-reflectivity.

The rationale for the weightings has been discussed in section 2 of this document.

8.1.2. Conclusions

From the above we can observe that Option 4 which is the Dynamic Model with Postage Stamp has the highest score. As discussed above this model is a locational model which uses a postage stamp adjustment to ensure revenue adequacy. The SOs have further modified this option to include a limitation that the locational element of the model shall be limited to a certain preset percentage of the overall revenue requirement. By ensuring that there will always be a significant proportion of the annual revenue requirement recovered by a uniform postage stamp charge this decreases the potential volatility and increases predictability and transparency of this model. It can be said to incorporate the best elements of the Option 3, the Dynamic model together with Option 5, the Postage Stamp option. It combines both approaches without losing its integrity. Option 3 model also scored highly but it was determined that it did not account for volatility or transparency adequately. It did however score the highest of all the options regarding efficiency and cost reflectivity.

No scores were applied to Option 6. This was because this particular option was found to be impractical. No satisfactory operational model was conceived for it.

8.2. Comparison of Losses Options

The table below outlines how the different losses options were evaluated based on the criteria weighting as expressed in section 3.

Objective	**Weighting**	**Losses Options**							
		Short Term						**Medium/Long Term**	
		TLAF	**Rolling Av**	**Banding**	**Compression**	**Zonal**	**Uniform**	**Splitting**	**Purchase**
Efficient Dispatch	0.25	4	2	2	3	2	1	5	5
Efficiency	0.20	2	3	4	4	2	3	3 - 5[23]	3 - 5
Cost Reflectivity	0.20	4	2	2	3	1	1	1 - 5	1 - 5
Volatility	0.15	1	3	3	3	3	5	1 - 5	1 - 5
Predictability	0.15	1	3	3	2	3	5	1 - 5	1 - 5
Transparency	0.05	3	3	3	3	2	4	1 - 5	1 - 5
Total		**2.65**	**2.55**	**2.75**	**3.05**	**2.1**	**2.75**	**2.4 - 5**	**2.4 – 5**

Table 14: comparison of losses options

[23] This is in order to clarify that under these options there is scope to undertake a number of different approaches.

The different losses options were scored, in relation to the objectives, with a score between 1 and 5. The scoring was allocated based on the extremes i.e. 1-5. The table is divided into 2 sections – Short Term Options and Medium/Long Term Options.

8.2.1. Short term losses options scoring

Under the Short Term Options the current TLAF methodology, 3 TLAF based methodologies, the Zonal and the Uniform options were included. The current TLAF Methodology was seen as driving the most efficient short term dispatch of all short term options. It was allocated a 4 to reflect the fact that a more real time loss factor would be the most effective solution to ensure the most efficient short term dispatch. The Compression TLAF received a scoring of 3 as it is a dampening of the current TLAF methodology. The Uniform losses option was given a scoring of 1 highlighting the lack of differentiation between participants under a socialised system in terms of losses.

The Compression Factor Option and the Banding option scored highest in the Short Term Options under the Efficiency criterion. These options deliver a well-balanced solution between encouraging generators to locate in appropriate locations while also reducing the overall cost of investment for potential projects by limiting the extremes of the TLAFs. The Zonal Option scored lowest under the efficiency criterion as there is not a strong enough signal to locate in well reinforced areas and neither does it really reduce the overall cost of investment for potential projects.

The current TLAF Methodology scores highest under the cost reflectivity criterion with a score of 4. Under this methodology generators pay for the losses they incur and benefit from the losses they offset – again it is recognised that a more cost reflective system would be real-time loss factors. The Compression method still penalises generators for incurring losses while offering benefits to generators for off-setting losses, albeit at a reduced level compared to the current methodology. The Uniform Losses Option scores the lowest here given that the overall cost of losses are socialised among all market participants. Cross-subsidisation also occurs as a result of generators not being penalised or benefiting from their respective locations.

Under the last 3 criteria (Volatility, Predictability and Transparency), the Uniform Losses Option scores highest in each instance. Under a socialised system of apportionment of losses the cost of losses will be fully non-volatile, predictable and transparent. The Transparency is slightly reduced as a methodology would have to be introduced to calculate the Uniform Loss Factor to be allocated. The current TLAF methodology scores worst under these criteria given the inherent volatility and unpredictability of this methodology. The other 4 options are more or less equal in terms of these 3 criteria and are scored accordingly.

8.2.2. Medium & Long term losses options scoring

Under the Medium & Long Term Options both Splitting and Purchase of Losses were scored equally. They both lead to the most efficient short term dispatch. The efficient dispatch can be derived from the tools at the disposal of the Transmission System Operators at any given time.

Under the next 5 criteria the Medium & Long Term Options have scores ranging from 1 to 5. This is in order to clarify that under these options there is scope to undertake a number of different approaches. For example, depending on the method chosen to allocate the cost of losses to participants, a socialised allocation method or a fully locational one can be chosen. Therefore, under cost reflectivity, as under the other criteria, this will lead to a range in scores from 1 to 5 respectively. Both methods are scored equally because purchase of losses could simply be a development of the concept of splitting and therefore not fundamentally different.

Overall efficiency is scored between 3 and 5 under these 2 medium/long-term options. The TSO will ensure the most effective method possible is implemented to support efficient generation investments and encourage long term investments in well reinforced areas. A Uniform Loss Factor could be used under the splitting and purchasing concepts – providing a lower boundary efficiency score of 3. Alternative means may lead to more efficient solution being achieved and therefore potentially a score of 5.

From the potential short term options the Compression model has the highest overall score value. It does not compromise, to a large degree, on efficient dispatch and efficiency. In addition it addresses some of the concerns expressed by the wider industry in that the volatility, the predictability and the transparency are all improved using this methodology. Under the Medium and Long Term Options, both splitting and purchases of losses have the potential to promote maximum advantages in terms of the 6 criteria.

9. Preferred Options and Rationale

9.1. TUoS Preferred Option: Option 4: Dynamic Location Signals model with Postage Stamp [24]

The aim of a location signal in the TUoS tariff is to differentiate between the impact that participants have on the transmission network. Participants who drive transmission investment or make more use of the system than others will pay higher TUoS tariffs, hence costs are attributed, to some degree, to those responsible for causing them.

After careful consideration of all the TUoS option outlined it was determined that Option 4 which is the Dynamic Model with Postage Stamp was best placed to meet the project's objectives to the best extent possible. This is seen in the scoring achieved by this option in section 8.1. To reiterate – this model sends a signal to participants regarding their contribution in driving the need for future network developments. The locational charges reflect the Net Present Value (NPV) of the recovery rate cost of these future developments.

9.1.1. Summary of preferred TuoS Option 4: Dynamic Location Signals model with Postage Stamp

It was recognised that rather than allowing the locational element of the tariff to recover the whole annual revenue requirement, should that situation ever occur in future, that Option 4 would consist of a maximum of 60% of the locational element of the tariff while the remainder would be collected on a postage stamp basis. In some years when the locational element of the tariff collects less than the 60% of the annual revenue requirement the postage stamp component of the charge shall be more than 40%. Restricting the level of locational charges was done in order to maximise predictability and to attempt to lower volatility of resulting tariffs. Nevertheless, it is envisaged that the tariff would still send an important location signal to participants.

[24] Previously known as Dynamic Model with residual

An important economic concept is that only future costs can be minimised and not sunk costs. Therefore, a tariff model should be framed around driving the minimisation of future costs. This is in order to provide efficient solutions that will benefit society. In other words, to minimise the tariff revenue requirement and ensure costs are incurred effectively. However, one must acknowledge that while the assets are sunk, these assets still have future payments attributed to them. These charges are unavoidable (although the rates may change) and therefore it is reasonable to socialise a proportion of these costs.

In order to respect the economic concept of being only able to minimise future costs, the SOs believe it is reasonable that the greater allocation of 60% (maximum level) in the TUoS tariff is attributed to the Dynamic locational signal. Furthermore, the 40% (minimum level) for the postage stamp element represents an appropriate allocation of costs that cannot be avoided.

The limit of 60% would mean that the lumpy nature of investments will not distort the overall tariff and introduce unnecessary volatility for participants. The locational element of the indicative tariffs calculated for this tariff option collected approximately 35% of the revenue requirement. However, with the planned increase in network developments the Dynamic model (locational element) will be collecting more of the revenue requirement. Therefore, the potential volatility could become an ever increasing issue. The introduction of a limit will constrain this impact.

The indicative tariffs that were calculated for the Option 4 do not reflect an important component of this option. While the model is primarily focused on future investments it stills charges for these future assets after they have been built for a period of seven years. This avoids a free-rider problem whereby participants could connect after the asset has been built in order to avoid contributing towards the cost of the asset. However, as the indicative tariff would be the first year of such a tariff option there are no previous future assets which need to be charged for. Over the forthcoming years assets will remain in the tariff until the seven year period is completed and therefore this increases the amount of the tariff that the dynamic element recovers. The tariff's consistency with future network plans will also add to the predictability as knowledge of the plans will be communicated. Furthermore, this will contribute to the transparency of the option as the TSOs would be in a position to publish indicative tariffs for a number of years ahead.

Given that, this option will at least collect 40% of the tariff revenue requirement through a postage stamp element it can be better described as a Dynamic Location Signals plus postage stamp tariff. Henceforth, the preferred TUoS model will be referred to by this name.

Overall, this option successfully accommodates and meets a number of the objective criteria set out in the May Consultation Options paper. The composition of the methodology means that it creates a forward investment looking location signal. This will support efficient network investment. Such a signal reflects a key principle of economic theory i.e. marginal cost pricing. Only future costs can be minimised not sunk costs, effective tariffs should be shaped around this important principle. Participants that create a need and utilise future network developments will specifically contribute towards the cost of the development. This cost reflectivity assists in supporting efficient grid development.

9.1.2. Implementation in Detail

Below is an outline of the steps involved in devising the Dynamic model with postage stamp.

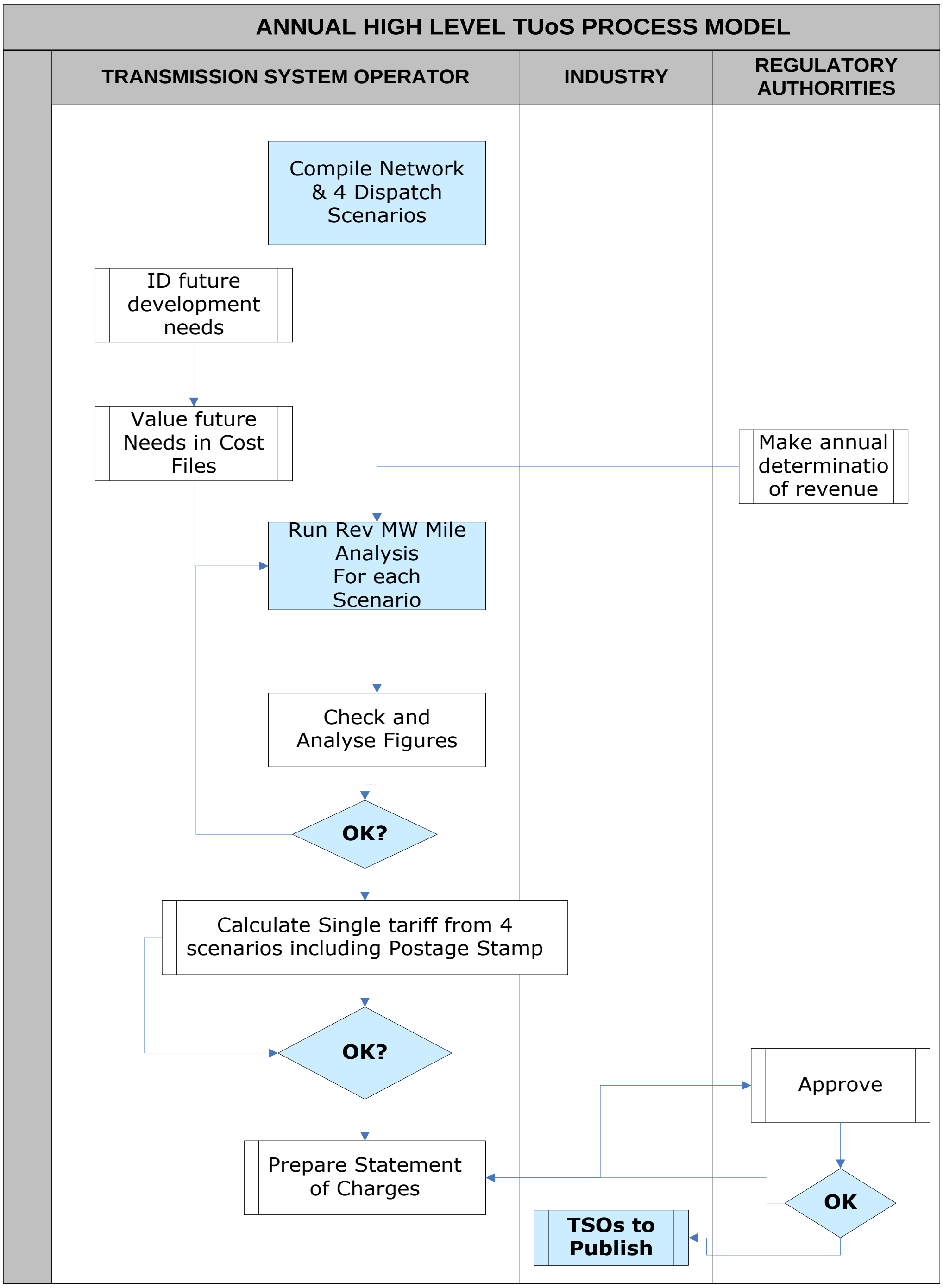


Figure 1: process for deriving dynamic model with postage stamp

9.1.3. Steps in preparing tariffs using Option 4 (Dynamic Location Signals model with Postage Stamp)

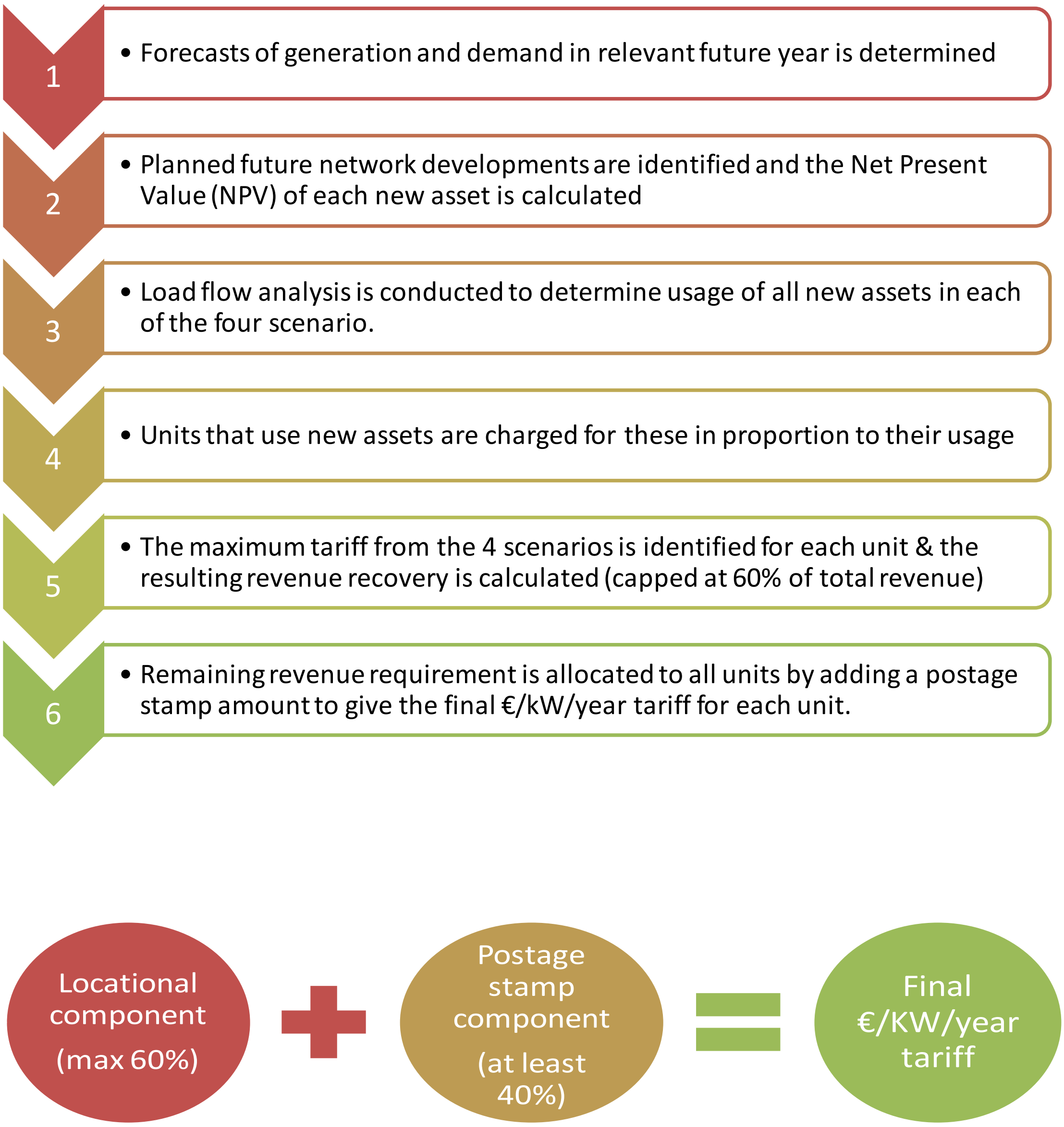


Figure 2: Implementation for Dynamic Location Signals model with Postage Stamp

9.1.4. Identify future developments

Firstly, a time horizon is selected. The indicative tariffs utilised a 5 year time horizon. However, a 7 year time horizon may be more appropriate as it would be consistent with the horizon provided by the Forecast Statement/ Transmission Seven Year Statement. The planned developments within this time frame are identified. They will be sourced from the projects that are included in the Incremental Transfer Capability (ITC) studies. This will be consistent with the Grid 25 network development plans and is representative of what is planned to occur.

9.1.5. Value of future developments

The second step involves valuing these identified developments. It is only these future developments that are included in the Dynamic (locational) element of the tariff. The assets are valued at the Modern Equivalent Asset Value (MEAV) but are inflated to reflect the time value of money using an expected inflation rate. It is important to note that the full cost of an asset is not included rather it is the annuitised recovery rate.

A simple example will illustrate this valuation process.

Say the below diagram is today's network.

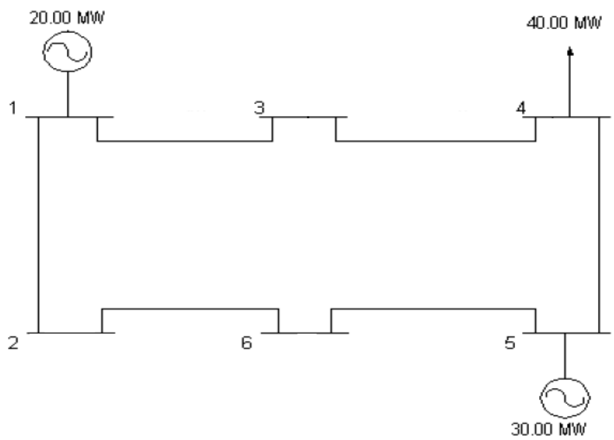


Figure 3: diagram for contemporary network

We then see in year 2 that the following network developments are planned to be undertaken due to the additional generation and demand. We get the NPV of the recovery rate value of the asset.

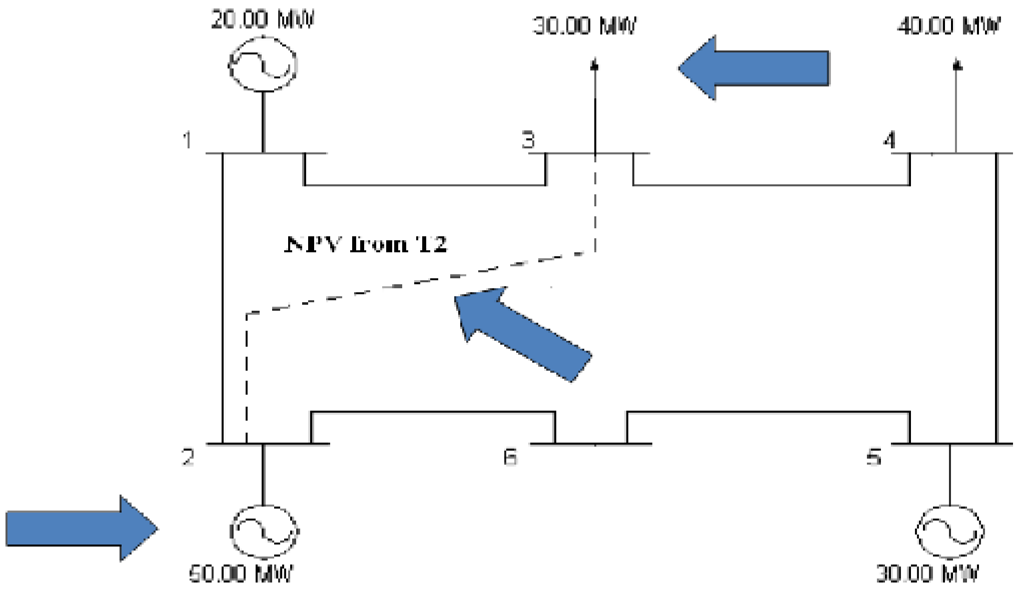


Figure 4: diagram for future network at time T2

Following on from this, we see in year 3 that further reinforcement is required for the additional demand on the system. Again, we get the NPV of the recovery rate value of the asset.

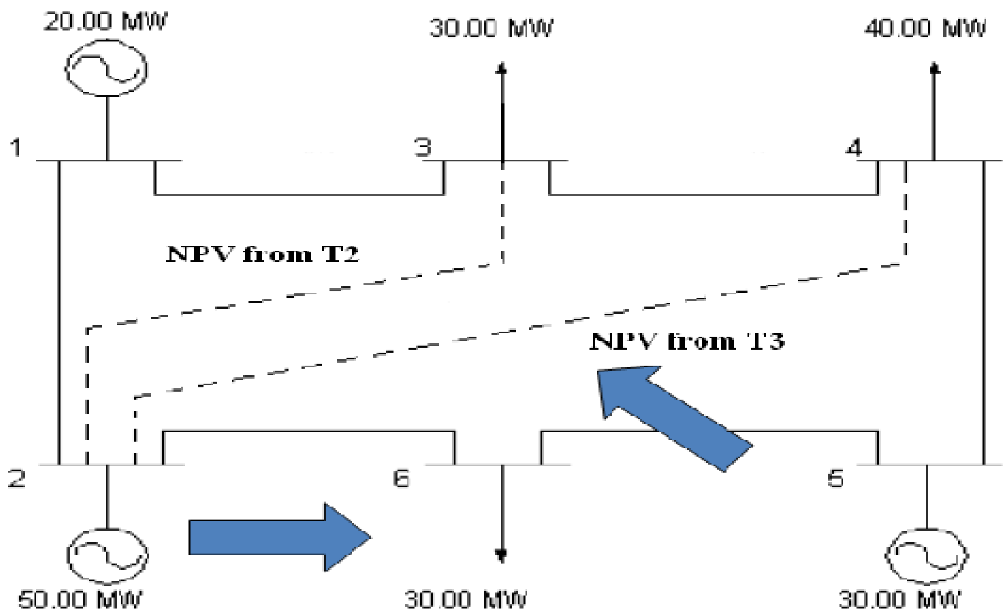


Figure 5: diagram for future network at time T3

This simple example highlights the fact that only future network developments are allocated to generators. In inflationary times the assets that are to be built further away will have cost the generators less. The closer one gets to when they are to be built the more expensive the lines become.

9.1.6. Allocate costs to participants

The utilisation of the Reverse MW Load Flow methodology ensures that network costs are allocated using a proportion ratio between power flow and network capacity. It offers a reward for off setting flows and does not recover the cost of spare capacity. The methodology would use a combination of four dispatch scenarios as explained in Appendix O. For the purposes of calculating indicative tariffs each generator's highest tariff from across the scenarios is selected because it is assumed that under that scenario the generator is driving the need for investment (See Section 5.1.2). This value is then charged to participants.

9.1.7. Ensure revenue reconciliation

A maximum of 60% of tariff will be allocated using the dynamic element. In practice a significant amount (at least 40% of the revenue requirement) will be allocated using a postage stamp method. The charge shall be levied on a capacity basis. If the locational charge element of the dynamic model recovers less than 60% of required revenue, then a postage element will be greater than 40%. It is important to note that the locational element of the tariff will never be greater than 60%.

9.1.8. Indicative Tariffs

The indicative tariffs as calculated for Dynamic model with Postage Stamp reflect the fact that the locational element was not beyond 60% of the tariff. That particular element collected approximately 35%. This illustrates that the postage stamp element may form the majority of the tariff. Please refer to Appendix K for the indicative tariffs.

9.2. Preferred Losses Option: 3-Step Strategy

Arising from the fact that no short-term option provided a maximum score from each criteria, the locational signals team have selected a 3-Step Strategy comprising of options for the Short Term, Medium Term and Long Term.

- In the Short Term there is 1 Preferred Option – the Compression Factor. (Oct 2010 or sooner if deemed appropriate)
- In the Medium Term the Splitting Option is put forward as a preferred option. (2-5 years)
- Finally, in the long term, the TSO will continue to evaluate the option to Purchase all Losses directly. (5 years +)

A losses methodology needs to reduce uncertainty and volatility for generators while also providing for efficient dispatch and 'reasonable' SMP for end-customers. This strategy is being recommended as it has the potential to be the most beneficial to the generators, the system and society as a whole, particularly in the context of changes that will take place in the coming decade, e.g. accommodation of wind and roll-out of the transmission grid across the island.

The short term preferred option involves a dampening of the volatility of the current TLAF methodology. This requires only a minor change of the calculation methodology. (See Section 8.2.1)
The medium term preferred option will, at the very least, require a minor change to the system dispatch software. Given that this software is intertwined with the market systems software, even a minor change could take 24 months and upwards to implement. (See Section 8.2.2)
The long term preferred option will require the addition of physical assets to the network and a possible major system dispatch software modification. (See Section 8.2.3)

This strategy was devised in order to satisfactorily meet the objectives (see section 3.1) in a practical manner. The medium term Splitting option (and consequently the Purchase of Losses option) has the potential to achieve the objectives more effectively than the short term option of the Compression Factor. Nevertheless, the Compression Factor is seen as a practical means that can be implemented in the near term and which addresses and meets the stated objectives.

Under the Splitting Concept a location signal for losses will not determine the ranking of participants in the market schedule. This will increase the certainty to be found in the market. Nonetheless, this does not rule out charging locationally for losses through another means outside of the market e.g. incorporated through an additional component in the TUoS charge. The use of an optimisation for losses in the dispatch will ensure that there is an efficient dispatch. Therefore, losses on the system will be actively managed and not neglected.

A number of issues remain regarding the introduction of either step of this strategy. The issues surrounding the Compression Factor can be overcome with relative ease. However, the Splitting option has a number of important hurdles to consider and decide upon. The Purchase of Losses also has issues regarding its implementation. These specific issues can be dealt with in the longer term. Whereas the issues associated with the Compression Factor and Splitting option require more immediate action. The flow chart below (figure 5) outlines the key issues and inputs required for each step of this strategy which have not been decided upon to date.

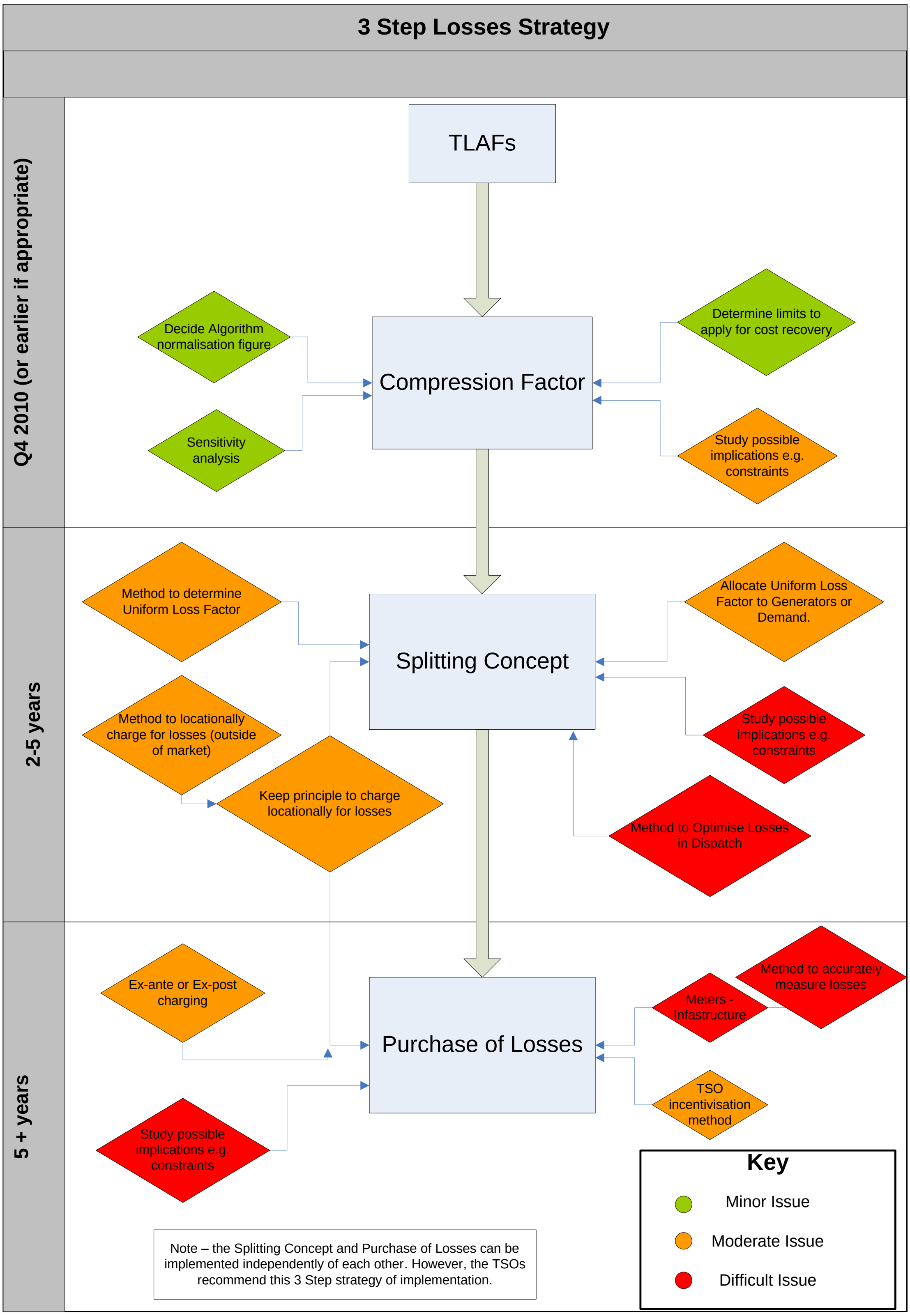


Figure 6: 3 Step Losses Strategy - Issues Remaining

9.2.1. Short Term: Description of Compression Factor

The purpose of a location signal in a losses methodology is to drive short-term efficient dispatch. This short-term efficiency should lead to the situation whereby dispatch is modified to reflect the cost of losses to the system. Overall costs will ultimately be minimised with such an approach and a signal should be provided for generation and demand to be located in close proximity to each other (as practical). This paper has analysed a number of options which utilised TLAFs or which involved a different approach.

After the analysis it was determined that the Compression Factor method was the most successful at meeting the desired objectives i.e. non-volatile, efficient, cost reflective, transparent, predictable and encourages efficient dispatch. This method is implementable in Q4 2010 (or sooner if deemed appropriate) and is being recommended in the short term as the preferred losses option. This method is considered to be a dampening of the regular TLAF method in an effort to reduce the effects of the volatility of the loss factors by 50%, hence improving efficiency, consistency and predictability. Essentially, limits are applied to the best and worst case TLAFs allocated. However, the methodology still ensures that generators incurring losses on the network are penalised and generators off-setting losses on the system are benefiting.

This methodology has many benefits in terms of the objectives mentioned above. The methodology reduces the effects of the volatility of the TLAFs by approximately 50%, is consistent, transparent and moderately predictable. The TLAFs do not drop out of a specified range so a generator can predict it's lowest / highest possible TLAF more accurately. The Compression Factor methodology also aids the efficiency of the TLAF while maintaining the locational signal. Generation is encouraged on to system in 'loss off-setting' locations knowing that if their location was to become 'loss incurring' then there is a limit on the lowest TLAF possible to be allocated. These limits thereby reduce investment risk and hence the cost of capital which should continue to encourage new generation on to the system and ensure the long-term security of supply.

The methodology reduces the cost-reflectivity of TLAFs to an extent as a generator incurring losses is not being penalised fully for them and similarly a generator off-setting losses is not benefited fully for that effect. However, the ranking is maintained, so the generator located in an area incurring the most losses will still be allocated the lowest TLAF and the generator located in an area off-setting the least losses will still be allocated the highest TLAF. The short term dispatch efficiency is reduced slightly under this methodology as the TLAFs have been manipulated to reduce the data spread. Market participants currently allocated very high TLAFs who may only export on an occasional basis will be impacted negatively by this methodology. The certainty associated with the limits may however, balance out this negative impact.

9.2.1.1. Implementation in Detail: TLAF Calculation Process

The process map below gives a High Level Overview of the TLAF process. It also includes the extra step required to apply the Compression Factor methodology.

1. A Market Model (Unconstrained Model) is created initially through Plexos using Network Model Inputs e.g. Recent Windfarm Connection Dates, Generation Outage Schedules, Hourly Demand.
2. From this model a Dispatch Model (Constrained Model) is generated through Plexos using additional inputs e.g. Fuel costs/constraints, System Constraints, Reserve Constraints.
3. From the 'Constrained Model', files are extracted and aggregated and used to generate Marginal Loss Factors in PSSE.
4. The Marginal Loss Factors, are then scaled and adjusted to meet system forecast losses.
5. Once these loss factors are computed the Compression Factor Algorithm will be applied.
6. The resulting Compression Factors will be submitted to the RAs for consultation and approval.

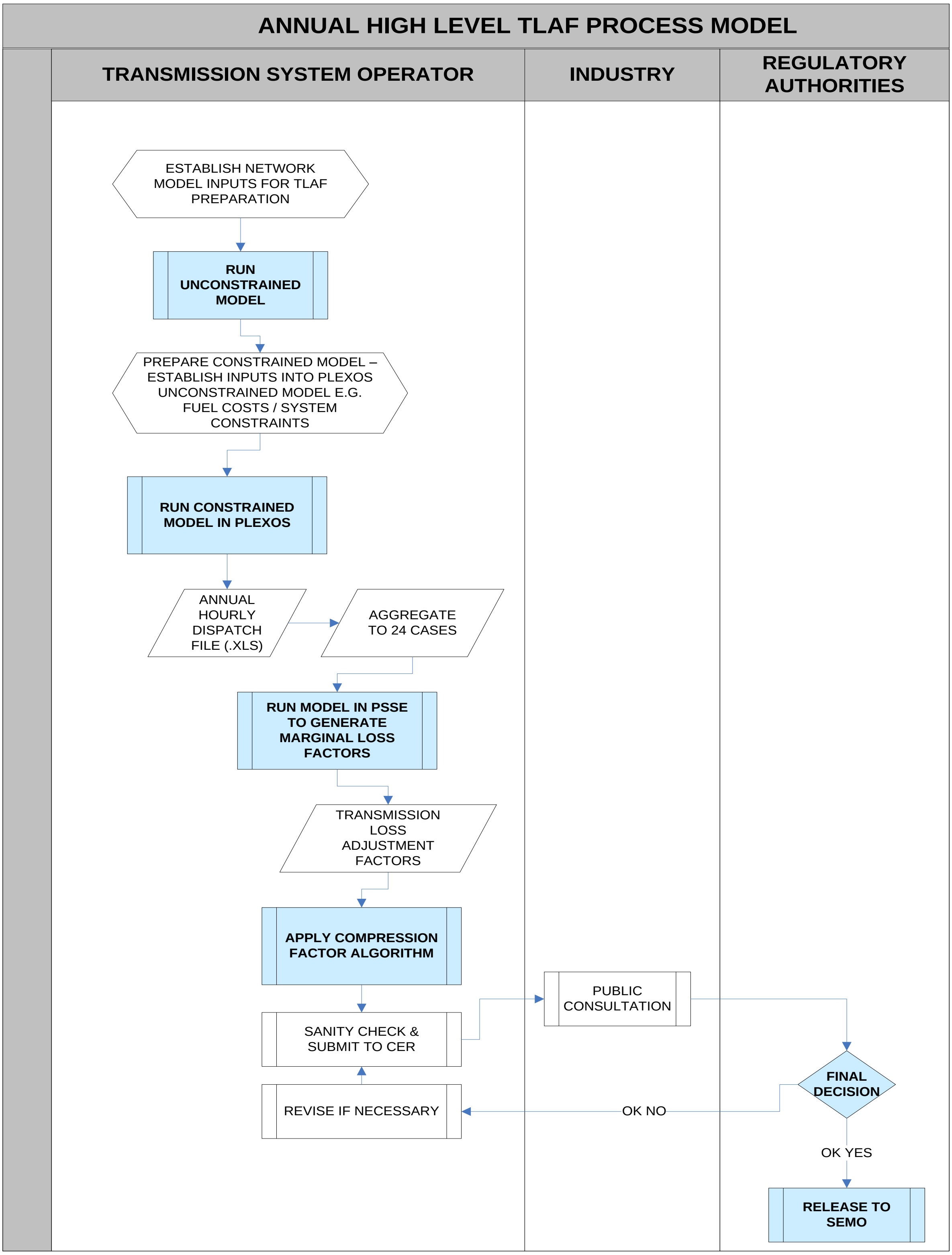


Figure 7: high level TLAF calculation process model[25]

[25] At present TLAF are produced for both day and night but this may be reviewed before implementation of any preferred methodology

9.2.1.2. Compression Factor Algorithm

The Compression Factor Algorithm is described in depth in Appendix C. The algorithm is a simple equation which is self-limiting. The algorithm can be normalised around any number. For the purpose of explaining the methodology the algorithm is normalised around 1. For a data set where X = TLAF and:

0.9 <= X <= 1.1[26]

If $X < 1$, $\frac{1-X}{2}+X$

If $X > 1$, $X-\frac{X-1}{2}$

Equation 1: Compression algorithm

The divisor in the algorithm is arbitrary and could be selected from any range of numbers. However, after some analysis it was decided to recommend '2' as the divisor due to the limited rounding off required and the retention of reasonable limits.

Under the above conditions, each generator TLAF in the range 0.9 to 1.1 (which encompasses all TLAFs) is 'squeezed' towards 1, essentially using an interpolation technique. Interpolation is a simple method of constructing a new set of data points within the range of a discrete set of known data points. Using this method, all generators keep their ranking i.e. the highest and lowest TLAFs will still be applied to the same generators. However, the range of data is reduced, the standard deviation is reduced, the mean is shifted towards 1 and hence the effects of the TLAF volatility are reduced. This is graphically illustrated in the 2 graphs showing statistical distributions below. The reduction in the data spread is highlighted as well as the slight increase in mean TLAF value.

[26] Taking historical published TLAF data, the TLAF has never been outside this range

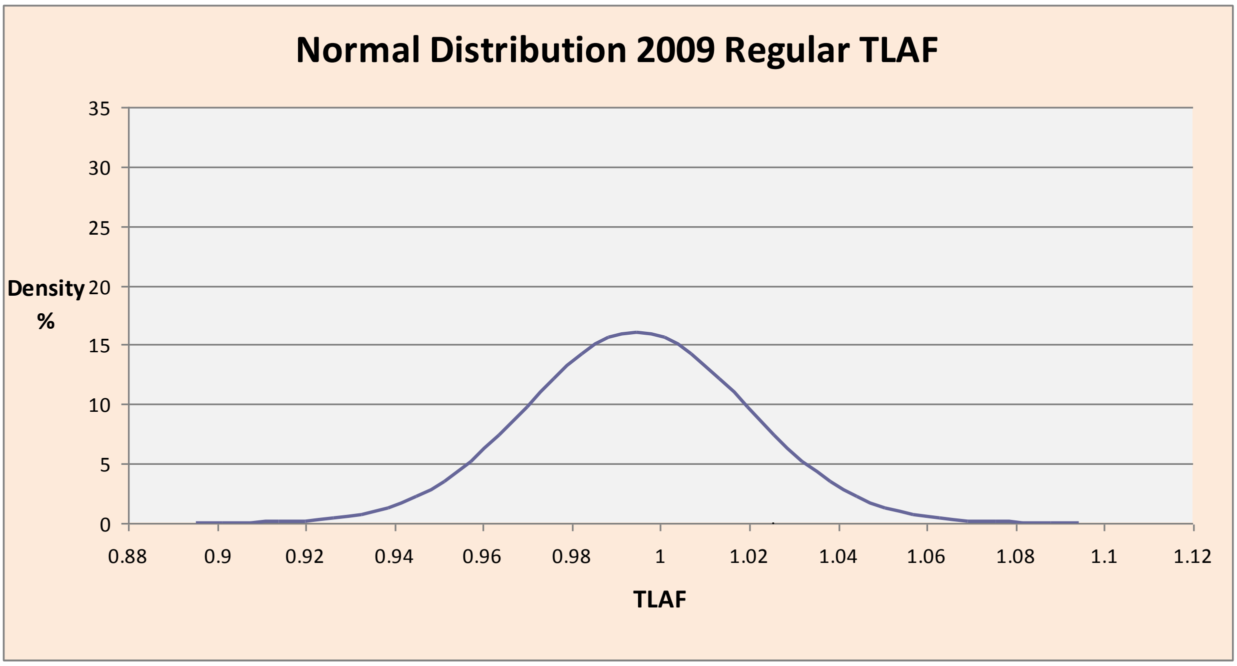


Figure 8 graph 1 – 2009 normal TLAF unweighted mean 0.995, statistical model estimating 16% of TLAFs on the average

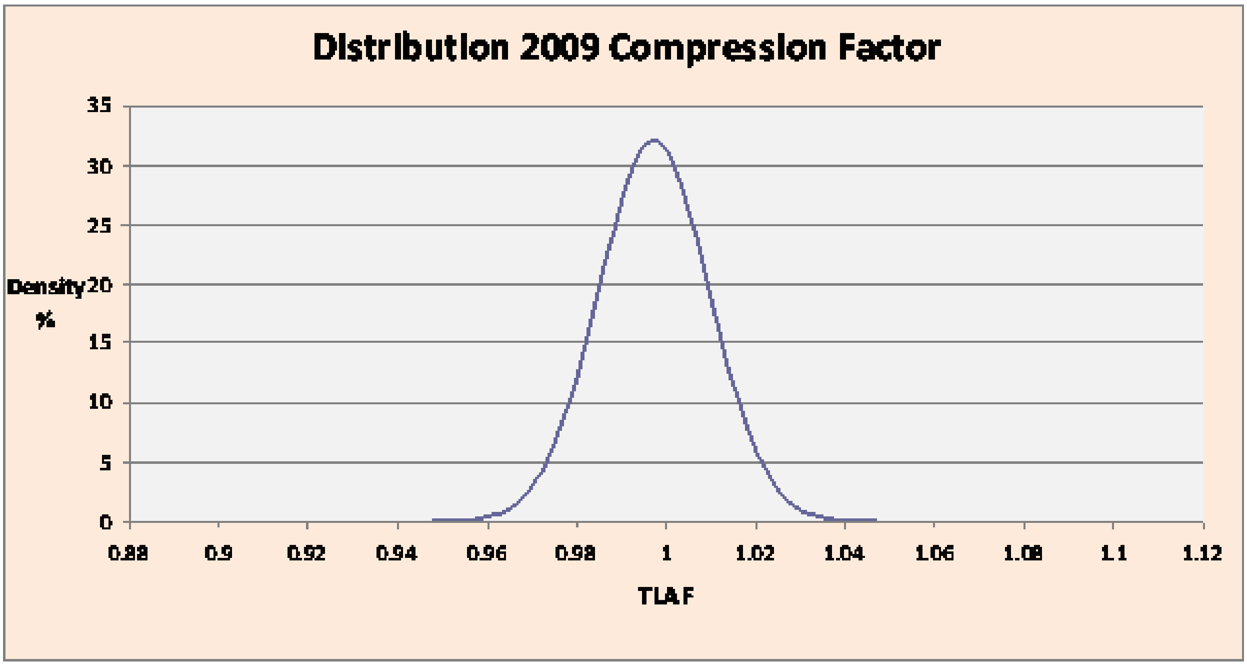


Figure 9: graph 2 - 2009 compression factored TLAF, unweighted mean 0.997, statistical model estimating 32% of TLAFs on the average, reduced data spread

9.2.1.3. Indicative Compression Factors

Comprehensive indicative Compression Factor TLAFs have been produced for 4 years – 2007, 2008 and 2009. These Compression Factor Indicatives are based on an algorithm normalised around 1. The Compression Indicative TLAFs can be found in Appendix I.

Three all-island maps are also included in Appendix E. Map 1 illustrates a representative sample of the All-Island TLAFs for 2009. Map 2 illustrates a representative sample of All-Island Indicative TLAFs for 2011. Finally, Map 3 displays an indicative sample of All-Island Indicative Compressed Factor TLAFs for 2011. A sample of the generators are chosen for this study in order to convey the volatility of the TLAFs between 2009 and 2011 and the resulting effects of the Compressed Factor TLAFs in 2011. An average annual TLAF is calculated for each generator. Generator TLAFs are highlighted clearly using a colour scale.

9.2.2. Medium-Term: Description of Splitting

A new concept was raised as a possible option during the analysis of the second phase of the project. This concept is essentially a medium term, 2-5 years, strategy to try and design the most effective way to drive efficient dispatch. This is very important considering the significant changes the electricity system will face in the coming years. For instance, there will be large diversification of the generation portfolio e.g. wind projects. Any methodology designed to drive efficient dispatch in terms of losses needs to be able to effectively manage such a portfolio. While the current TLAF approach can be considered appropriate for the current generation portfolio and system it may come under strain with the unprecedented forthcoming developments. A number of concerns regarding the current TLAF approach have been raised by industry participants who question whether the benefits brought by TLAFs in terms of efficient dispatch outweigh the potential uncertainty and associated cost. This issue needs to be considered in the context of what an alternative's, such as the splitting concept, implications will be.

Currently all market generation participants adjust their bids by their allocated TLAF to account for system losses. This adjusted bid is then fed into the physical dispatch calculation, which drives an efficient dispatch in the short term. The most accurate way to calculate the losses (and loss allocation) is to do the loss factor calculation in real time or as close to real time as possible. The current approach is an approximation to this.

The splitting concept involves separating the locational signal and cost recovery for losses from the market and developing a new method in the physical dispatch to try and achieve an efficient dispatch. In other words, removing the locational signal for losses from the market, introducing a uniform loss factor and modifying the systems which run the physical dispatch. Alternative means, which are not incorporated in the market, can be devised to charge locationally for the losses e.g. through an additional individual component in the TUoS charge. This could include longer term signals rather then the short term focus of the current method. However, further extensive analysis is required to devise this alternative charge.

9.2.2.1. Economic Implications

Careful consideration is required of the implications of implementing a uniform loss factor into the market. Any such change could damage the competitive advantage of some generators while others would benefit. A number of key areas will be discussed in turn. It is important to note that an impact in one area may have ramifications in other areas. In other words there may be some inescapable circularity in the impact of any change. The main areas include: SMP, Infra-marginal rent; changes in Volume of Losses and Economic Signals.

9.2.2.1.1. SMP

The SMP is set by the marginal unit. Therefore, when considering how a uniform loss factor will effect the SMP, the main consideration is how the new approach will affect which generation unit sets the marginal price.

With the majority of generators having a TLAF of less than 1, one could assume that the SMP will fall when they are removed (if the TLAF is less than 1 then the bids are adjusted upwards). However, this may not always be the case as the marginal unit may in fact have a TLAF that is greater than 1. Hence, at certain trading periods the SMP may be reduced while at others it may increase with any changes.

Therefore, one needs to be cautious in the interpretation of the impact a uniform loss factor would have on the SMP. Notwithstanding this, other factors (e.g. gas prices and carbon prices) will have larger effects on the SMP.

9.2.2.1.2. Infra-marginal rent

The introduction of the uniform loss factor could have an impact on how the merit order will be stacked. The most efficient plant in terms of generation cost will be selected in the merit order. It is unclear to what extent the merit order would be changed. However, any reordering will affect units' infra-marginal rent. The infra-marginal rent is the difference between a unit's bid price and the SMP times their loss adjusted market schedule quantity. Therefore, to determine the change to a unit's infra-marginal rent both the changes in the SMP and the market settlement quantity need to be examined and analysed. It is important to note that the merit order stack is dynamic and does change due to a number of different reasons. Therefore, this makes it difficult to pinpoint the impact that the introduction of a uniform loss factor would have.

9.2.2.1.3. Change in Volume of Losses

With the introduction of a uniform loss factor there is potential for the Error Supplier Unit (ESU) to be affected due to the resultant change in volume of losses. The uniform loss factor should be an estimate of the actual losses found on the system. Essentially if the actual losses found on the system differ from the estimated uniform loss factor then the difference will be accrued to the ESU. If the actual losses turn out be higher then the ESU will accrue more and visa versa. This is due to it picking up the non-metered energy.

This is similar to the current situation. If actual losses are different to what was measured by TLAFs then the ESU recovers the cost of the difference. It is unclear whether the change to uniform loss factors will increase the risk that a greater cost will accrue to the ESU.

9.2.2.1.4. Economic Signals

The inclusion of uniform loss factors will remove any economic locational signal in terms of losses from the market. The question arises whether this causes a distortion and will drive economically inefficient solutions.

From a pure principled approach it is clear that a distortion will occur, if there are no locational signals regarding losses. Generators will have no incentive to locate in areas that incur fewer losses than others. This may not be efficient for society as a whole. This is an important economic principle. Ideally a locational signal is required to ensure that all the costs associated with a location are evaluated before a decision to develop is undertaken. Otherwise, inefficient solutions which are value destroying to society could occur. The implications of having no signal for losses could have large negative implications for the development and sustainability of the electricity system. However, there may be a trade-off in terms of the distortion created by the removal of a location signal and the consequences of utilising a particular locational signal methodology. The benefits and negatives of each approach needs to be balanced to reach the most effective overall solution for society. Alternative charging methods, outside of the market, which require further analysis, can be devised to overcome inefficiencies of not having a location signal regarding losses in the market.

9.2.2.2. Implementation

The implementation can be separated into two stages. The first stage deals with the decisions regarding which approach to undertake regarding the charging for losses aspect of splitting. The second stage involves determining the technical requirements needed in the physical dispatch software to try and achieve an efficient dispatch.

9.2.2.2.1. Stage 1

A decision needs to be made whether the uniform loss factor should be allocated to the generation or supply side. The removal of generator loss factors could help solve some particular issues with the market design. For instance, there is currently analysis being undertaken by the SEM modifications committee regarding the Uplift calculation to ensure generators' cost recovery. The inclusion of a loss adjustment factor in the cost recovery calculation introduces some complexity which would be removed if generators did not have loss factors.

It can be argued that suppliers would not be adversely affected by having a TLAF (other than 1) attributed to them. Currently suppliers pay for the cost of losses through the SMP in the market. If however, a uniform loss factor was allocated to them the metered energy which they currently pay for would be adjusted by the loss factor. In effect they will be paying for the estimated quantity of losses on the system together with the metered demand. The cost of losses would be reallocated from the SMP to an increase in the amount of MWh bought.

With either approach there are two important elements that require further measured analysis before a decision can be made. These elements are applicable to whether generation or supply receives the uniform loss factor;

- The best method for estimating the losses found on the system needs to be chosen. A scope of all the estimation methods is required together with extensive evaluation and analysis of each potential method.
- Another important element that underpins the splitting concept is the requirement to devise an alternative means to send location

signals regarding the cost of losses in order not to lose this important economic signal. This underpinning is required if the principle of sending location signals for losses is desired. Again extensive analysis is necessary to devise an appropriate alternative location signals charging method for utilisation outside of the market.

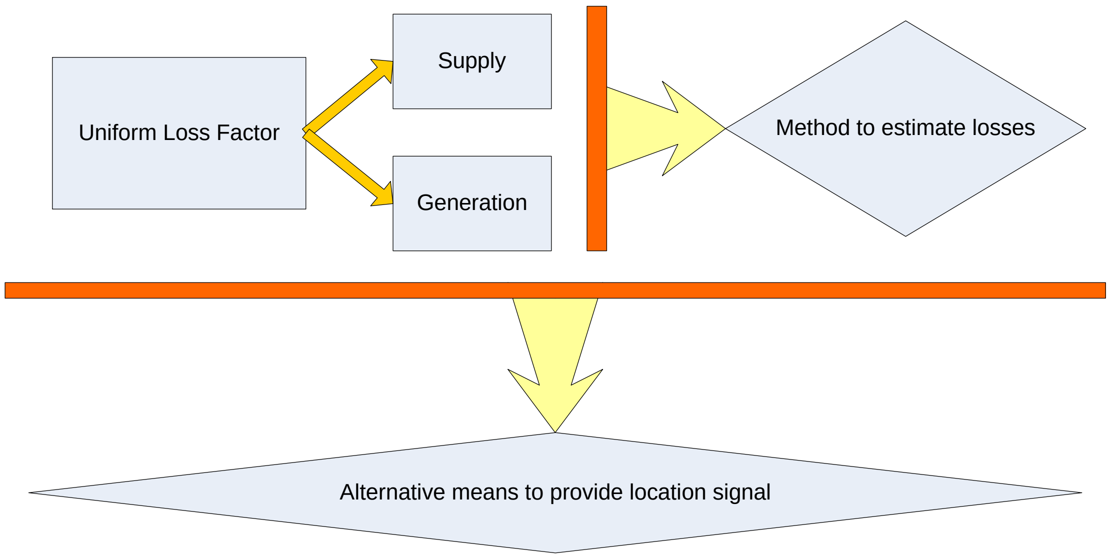


Figure 10: Splitting

9.2.2.2.2. Stage 2

It is envisaged in order to achieve an efficient dispatch directly through the mechanisms behind the physical dispatch that significant modification would need to be implemented in terms of system design. An extensive scope of work is required to determine these changes. However, from initial analysis it is estimated that even a relatively minor change to the physical dispatch system would incur considerable time.

EirGrid introduced Reserve Constrained Unit Commitment (RCUC) as an off-line dispatch scheduling aid to real-time dispatch with the introduction of the Single Electricity Market. This software tool utilises a Mixed-Integer Program (MIP) to perform Unit Commitment and Linear Programming to perform constrained Economic dispatch. A MIP is the minimization or maximization of a linear function subject to linear constrains. Linear

Programming problems determine the way to achieve the best outcome (such as maximum profit or lowest cost) based on a list of requirements which are represented as linear equations.

TLAFs are currently included with generator's Commercial Offer Data. This Commercial Offer Data filters through to the market on one hand and to the dispatch scheduler on the other hand. Losses are currently optimised through TLAFs in the dispatch scheduler. Without a locational signal in the form of TLAFs in this scheduler, there would be no means of optimising losses through RCUC as it is currently operated.

There are other options available for off-line dispatch scheduling such as Security Constrained Unit Commitment (SCUC) or Security Constrained Economic Dispatch (SCED) or potentially RCUC could be modified to optimise losses in some other way. Specialised technical studies are required to investigate the viability of optimising losses through any of these means.

Typically, a minimum of 2 years is required to proceed through the stipulated approval process for any system changes in RCUC (see flow chart below). This process is required because both the market and physical dispatch system are intertwined – changes to either affect both – as described above. At the very least a minor change will be required to implement the splitting concept (i.e. Uniform Loss Factor in the Market and Loss Adjustment Factor in the dispatch scheduler). Under the regulatory approved process illustrated below, this could take anything from 24 months upwards.

Outlined below in figure 9 is a flow chart of the approval process for changes to the system. As one can see a considerable number of steps are involved consisting of interaction between three parties – TSOs, software provider and the RAs – even for a minor modification. A key reason why the process takes a minimum of 2 years for minor changes is that are only two release periods in the year which restricts when changes can be deployed.

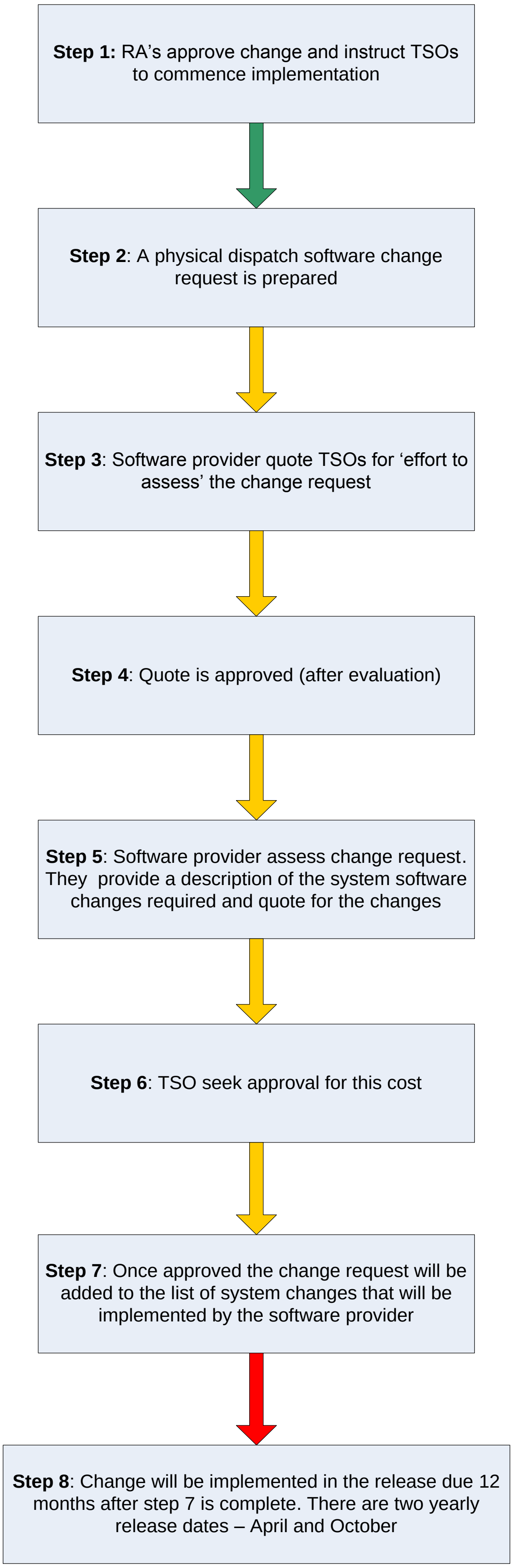


Figure 11: Approval process for system changes

In summary, the Splitting option cannot be implemented in the Short Term due to the following issues:

- A fundamental change (such as the Splitting option) to the established Losses Methodology has unknown consequences and requires further analysis before implementation.
- Uniform Loss Factors remove locational signals from the market and would be at variance with the intent of the SEM High Level Design Paper.
- Implementation of a Splitting option requires a significant modification as both the Market System Software and the Dispatch System Scheduler are intertwined. As described above, this modification process could take up to 24 months. A major modification could take from 2-5 years.
- To only implement Uniform Loss Factors in the Market in the short term would result in the introduction of a Uniform Loss Factor in the Dispatch Scheduler and, consequently, in an inefficient dispatch. To implement a more optimal solution in the dispatch scheduler would be a medium term endeavour.
- As a result of a Uniform Loss Factor the volume of losses in the system could increase and this would be at a greater overall cost to the consumer.
- A basis for the establishment of a Uniform Loss Factor must be determined and as it would clearly differ from today's methodology, this would not be feasible in the short term.
- Decision needs to be made on whether to allocate Uniform Loss Factors to Generators or Suppliers and the consequences of each approach fully considered.

9.2.3. Long-Term: Purchase of Losses

In the long-term the Purchase of Losses by the Transmission System Operators – SONI and EirGrid – is currently proposed as the preferred option in the final step of this 3-step strategy.

- The purchase of losses may be appropriate to introduce as a development of the 'Splitting' concept (described in section 4.2.1);

- The current SEM market design would have to be modified to incorporate Purchase of losses. In certain case studies examined by the project team, the cost of losses is often passed back to generator customers through postalised tariffs or similar charges. It may be possible to incorporate a marginal loss factor per node and use this as a non-postalised way of spreading losses. Further alternative locational charging methods would also be possible;
- Purchase of losses would also require considerable infrastructure investment. At present EirGrid does not have the metering infrastructure in place to support this particular methodology. Its implementation would be beyond the timeframe of this project. The reality is that it would take at least 5+ years to implement it in full;
- In order to predict losses for operations it will be necessary to use both historic data and specialised software for intra-hour purchases. The experience of a number of TSO in Europe is that specialised load-flow based solutions are necessary to fulfil this requirement;
- The commercial impact of such an approach would need to be considered as part of a long term regulatory review of operations of the TSOs. An in-depth study will be needed in order to identify the risks, costs and benefits for all stakeholders of introducing purchase of losses.

9.3. Transparency

In order for System Operators to enhance the transparency of charging and losses methodologies there are a number of steps that can be taken. Obviously as more of the techniques mentioned below are adopted the more transparent the methodology will be to industry groups. Possible methods to improve transparency of losses will be very similar to those for tariffs therefore below we refer only to the tools applied to tariffs on the assumptions that these could also be applied to the losses methodology.

In brief, the main tools used to promote transparency of any Use of System tariff methodology include:

- Produce Indicative tariffs for future years;
- Prepare and published approved Charging Statements;
- Produce and publish a detailed explanatory paper of the methodology;
- Put in place a tariff/losses workgroup within a Transmission User Forum;
- Published proposed modifications;
- Hold Regular Workshops with interested groups; and
- Complete requested tariff studies (at a cost).

1. Produce Indicative tariffs for future years

Information is published at least once a year on the forecast future path of tariffs under a range of credible generation and demand scenarios consistent with those already contained in the Seven Year Statement).

2. Prepare and published approved Charging Statement

Charges for connection to and use of its transmission system are published. Copies of previous years' Charging Statements including historical Transmission Network Use of System tariffs are also made available.

3. Explanatory paper

A paper describing the methodology used to derive the tariffs is published each year. This paper is very detailed and provides all necessary information for those interested in tariffs.

4. A Transmission Users' Forum

An industry forum will be set up to discuss charging and losses methodologies and the principles behind them. The aim of the forum is to allow Users to become involved in the development of the charging and losses methodologies and enable the TSOs to keep them under constant review. All existing or prospective Connection and Use of System parties are eligible to send one representative to the meeting. In addition, representatives from other industry bodies are invited. This group could review the accuracy of prediction of tariffs for forthcoming years also.

5. Proposed Modifications published

The TSOs keep Charging Methodologies under review at all times and make modifications to the methodologies that would better achieve the relevant objectives. The relevant section of the TSO website shall be used to publish information on proposed modifications on charges and charging methodologies and track their progress through the modifications process.

6. Regular Workshops

The TSOs proposed that regular (at least every 6-9 months) workshops be established to meet with interested parties and present relevant information. This allows participants a chance to raise any questions.

7. **Specific tariff studies can be requested**

The facility to allow industry group to request a specific tariff/losses study to be conducted could also increase transparency. For example a new 400MW generator considering connecting in the SE in 2013 could ask for tariffs to be produced for 2013 including this unit. A charge for this service would be required.

10. Next Steps

1. TSOs to Consult with Industry

As with the Options Paper published in May, the industry will get an opportunity to respond to this paper both in written form and by means of a workshop. These responses will be reviewed and collated in a short paper from the TSOs to the RAs.

2. RAs to provide decision paper on tariffs and losses methodologies.

Using both the TSO short paper described in 1 and other sources the RAs will consider the proposals. They will then prepare a response paper on the subject of transmission tariffs and losses.

3. Additional Studies

There are a number of studies and work packages that will need to be completed in order to smooth the way for the adoption of the new methodologies:

a. Cross Border Finance;
b. Implications for Non-Firm tariffs;
c. Split between Postage stamping and location element in TuoS proposal;
d. Implication of reducing lower threshold to 5MW;
e. Additional Software evaluation;
f. Further quantitative analysis of losses methodology on constaints, SMP etc.
g. Operational Impact assessment of TuoS methodology; and
h. Operational Impact assessment of losses methodology.

4. Implementation Schedule

The proposed short term losses and tariff methodology will be implemented before Q4 2010 assuming that the RAs decision paper is available in early 2010.

In order to develop and implement the splitting concept a project will need to be started which will identify the market, technology and policy changes required to support the methodology. The full implications of each element have not been developed beyond what has been discussed in this document. In order to deliver the project in the next 2-3 years (at the earliest) it would be necessary to commence work in mid 2010. As with all major changes, the implementation of this methodology may be impacted by extrinsic factors outside the control of this project e.g the long term development of the market. Therefore, it will be necessary to regularly review such developments to ensure that the splitting losses option is still appropriate for the Island of Ireland.

Purchase of losses is final step and needs considerable investment in metering technology. The rollout of this equipment is beyond the scope of this project and a timeframe for its completion is not available at this point in time.

Appendix A
Losses
Study on Rolling Average TLAFs

Implementation

A study has been carried out on the viability of the 3 Year Rolling Average Method. The 3 Year Rolling Average Methodology consists of taking the TLAFs allocated to a particular generator for 3 consecutive years and finding the Monthly Day and Night Average of that TLAF and allocating the calculated average TLAF. For example the 2009 TLAF is required for a generator. The TLAF for the years 2007, 2008 and 2009 are collated. The average day and night TLAF from the 3 years is calculated and assigned to the generator in the year 2009.

Study Method

The study focused on a small number of generating units:

Generators with:

- Low TLAF
- Average TLAF
- High TLAF
- Low Volatility TLAF
- High Volatility TLAF
- High Year on Year Volatility

- In the case of an example of a generator with a low TLAF the Averaging Method appears to reduce the standard deviation and range of the TLAF and also reduce the annual mean. For this example the TLAF appears more stable.
- A generator with a medium/average TLAF across the range shows very little change in TLAF with the exception of the reduction of the effects of any deviations from the Annual Mean TLAF.

- A generator with a high TLAF, e.g. Marina, shows an improvement in TLAF stability in 2008 & 2009 between regular TLAF and Rolling Average TLAF.
- A low volatility TLAF allocated to a unit displays very few changes using the 3 Year Rolling Average Method however, there is a slight reduction in the spread of data.
- A TLAF, which is highly volatile within the year, allocated to a unit again displays very few changes with the exception of a slight reduction in the spread or standard deviation of the data.
- A highly variable TLAF over a number of years again shows only a slight improvement under the 3 Year Rolling Average Methodology. The TLAF stabilises slightly but, as in the case of Meentycat for example, there is only a marginal difference.

Criteria Addressed

Efficient Short Term Dispatch: The 3 year Rolling Average Method will reduce the efficiency of the Short Term Dispatch. The Averaging Method will dilute the locational signal element. The method is a dampening of the effects of the current methodology – while reducing the negative aspects of volatility it also reduces positive aspects of efficient short term dispatch.

Efficiency: The 3 Year Rolling Average Method increases the efficiency (in terms of use of network and future grid investment) of the TLAF slightly by means of reducing the volatility. However, it would not reduce the cost of investment capital and therefore would not help encourage new generation on the system in beneficial locations. Especially for the first 2 years, the TLAFs would be calculated as previous and may increase business risk for generation and make investment more difficult. It is still an improvement on the current methodology.

Cost Reflective: The Cost Reflectivity is also reduced under the 3 year Rolling Average Method. In the case of a highly volatile TLAF, if the TLAFs generated for a unit are 1.04, 0.96 and 1.00 and under the Averaging Methodology the TLAF is reduced to 1.00 , it is seen that the TLAF is not fully cost reflective. However, in the case of a Unit with an approx average TLAF, e.g. Huntstown, the 2009 TLAF = 0.990 and the 3 Year Rolling Average TLAF = 0.986. This would indicate only a slight reduction in Cost Reflectivity. Irrespective of the individual magnitudes, there is still an overall reduction in the Cost Reflectivity as a result of this methodology.

Volatility: The volatility is reduced using the rolling average method as is seen from Graphs 10 and 11 below. A CCGT with an historically low TLAF is used for the example and, from the Graphs, the range is reduced slightly and the standard deviation is reduced. When a CCGT with a TLAF, which is very volatile and has a high standard deviation, is examined the rolling average method has the effect of a slight reduction in the TLAF range.

Predictability: The predictability of the TLAF is improved to an extent as the 2 previous year's TLAFs are known. It would be possible to predict the differing effects of a high/low TLAF on the 3 year average TLAF.

Example. 1: 2 year Average TLAF for January Day = 0.963, if a high TLAF of 1.04 is expected for the following year(s) (due to disconnection of generation, increased load, expected loss of dispatched energy) the unit can calculate an approximate 3 year Rolling Average TLAF in advance of 1.0015. (This example also indicates the reduction in volatility)

Transparency: The 3 Year Rolling Average Method is an additional step on to the current methodology and so there would be no increase in transparency.

<u>Issues</u>

As highlighted above, the main issues associated with this Methodology would be:

- As new generators connect on to the system there is a 3 year waiting period before the Methodology can be applied in full. This reduces the efficiency and the consistency of the methodology.

- There is a reduction in efficient short term dispatch under this methodology.
- This method reduces the cost reflectivity of the TLAF and so it is possible that the losses are not fully recovered.

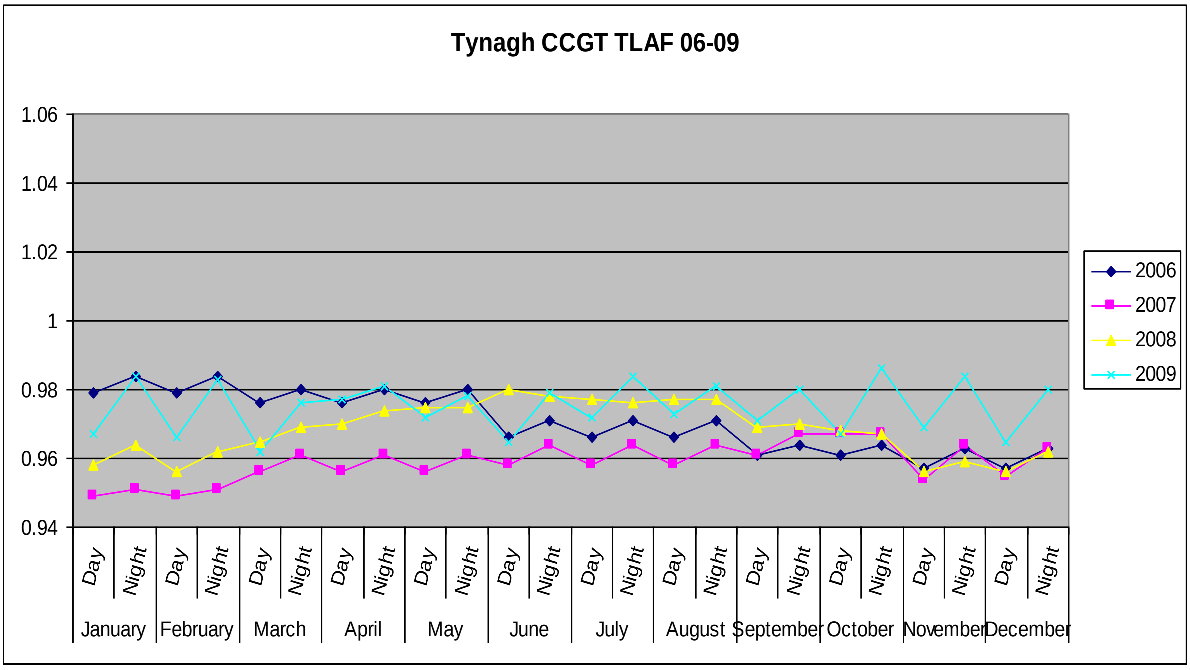


Figure 12: Tynagh TLAF 06-09

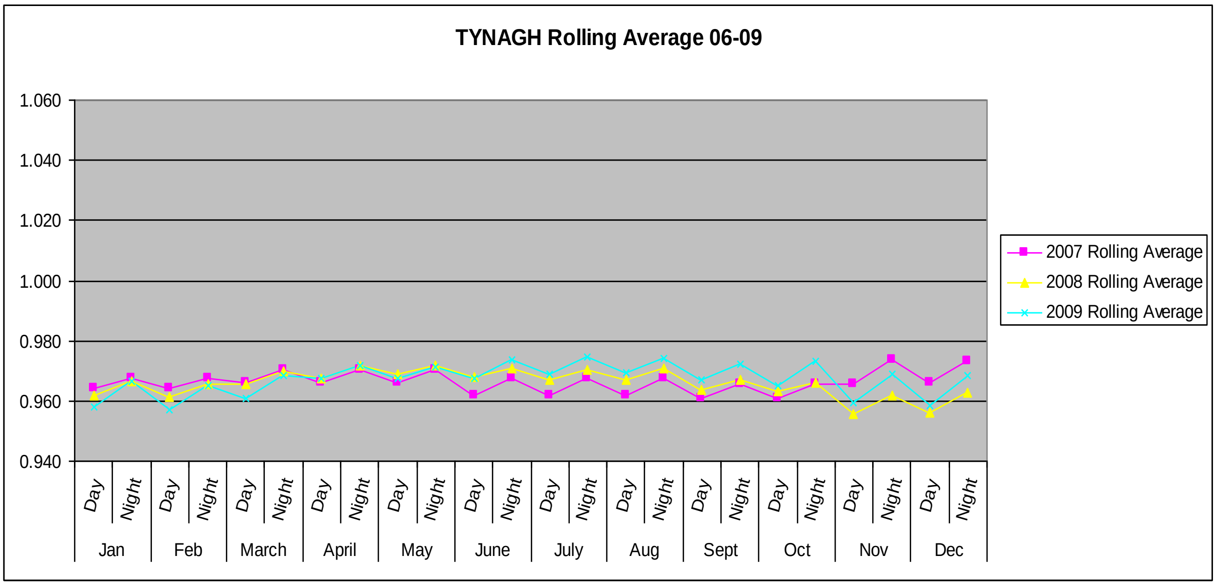


Figure 13: graph 1 & 2 – the graphs show a CCGT with a low TLAF using regular TLAF methodology and rolling average methodology.

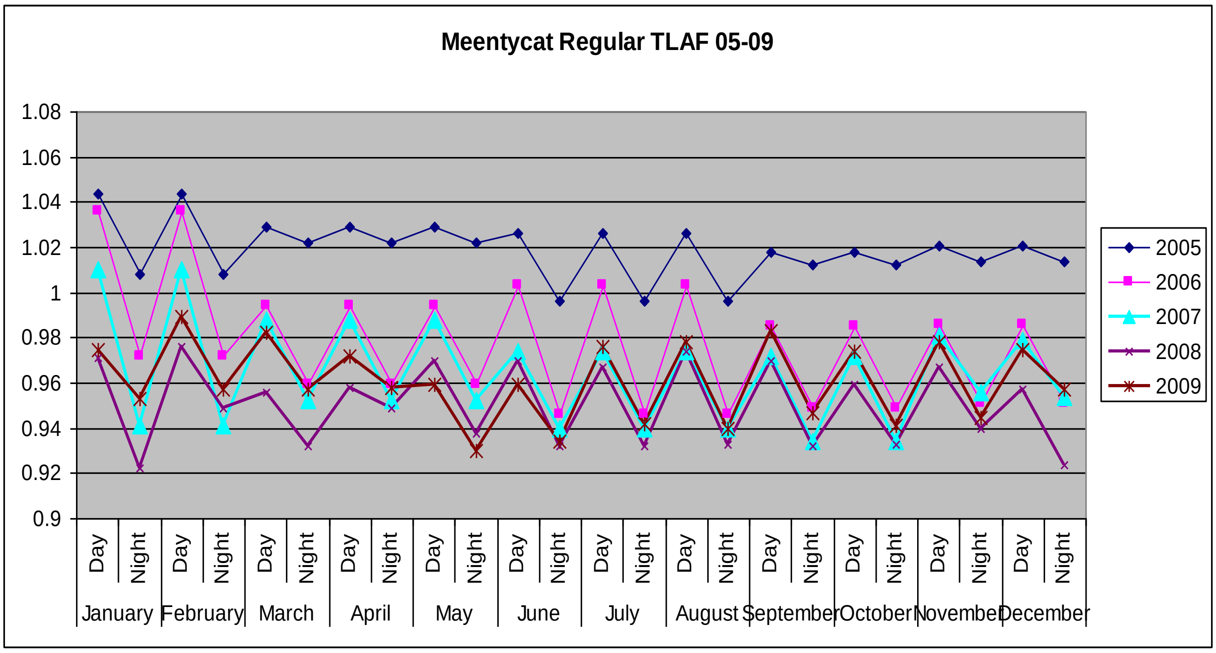


Figure 14: Meentycat regular TLAF 05-09

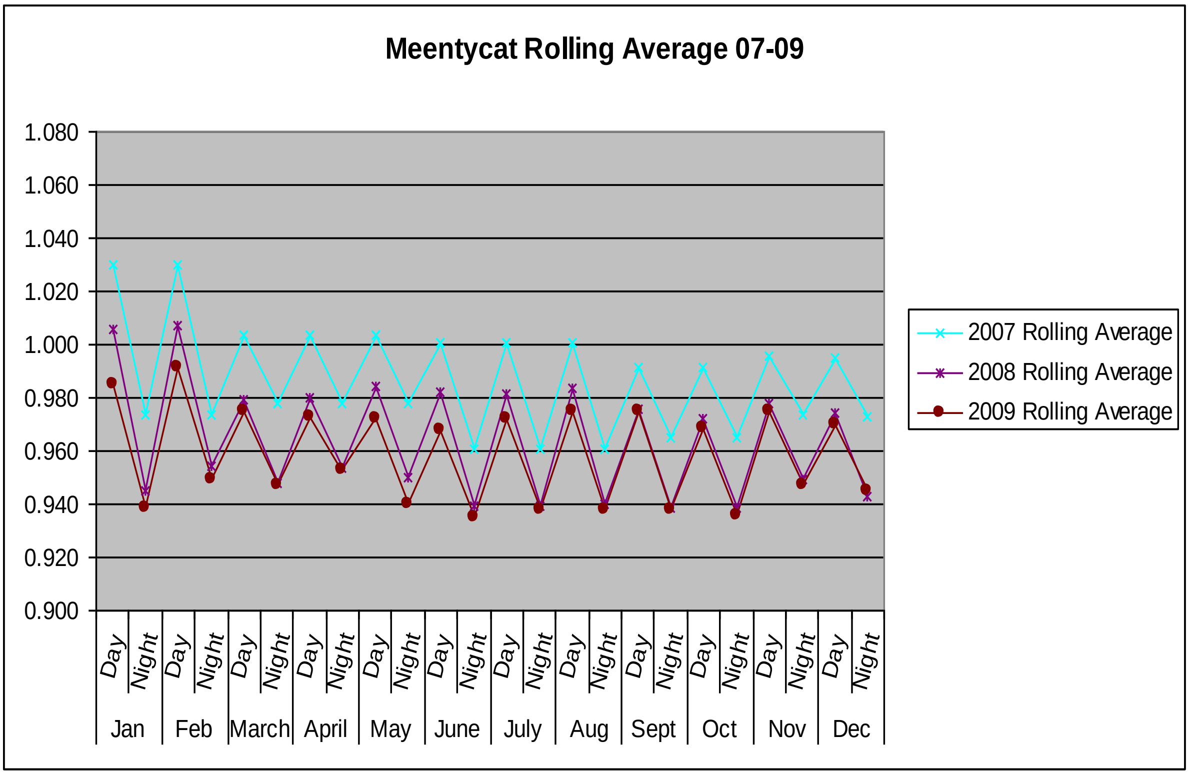


Figure 15: the above graphs show a generating unit with a high variability in TLAF over a period of years using regular TLAF methodology and 3-year rolling average methodology

Appendix B
Losses
Banding LAFs

<u>Implementation</u>

The 'Banding Method' simply takes each individual TLAF and groups (or bands) it in accordance with its value. The implementation of this Method would be relatively simple. Taking the regular Loss Adjustment Factors and running them through the calculation spreadsheet will output the Banded Factors. The new factors are then allocated to the Generators.

<u>Study Method</u>

The Study Method below explains this method:

Banding Table	
Old TLAF	**New TLAF**
0.9-0.92	**0.96**
0.92-0.94	**0.96**
0.94-0.96	**0.96**
0.96-0.98	**0.98**
0.98-1.00	**1**
1.00-1.02	**1**
1.02-1.04	**1.02**
1.04-1.06	**1.04**
1.06-1.08 1.08-2	**1.04** **1.04**

Table 15: banding table[27]

Looking at the Banding Table

- any Loss Adjustment Factor < 0.96 is increased to 0.96;
- any Loss Adjustment Factor <0.98 and >= to 0.96 is increased to 0.98

[27] These bands are chosen arbitrarily and are subject to change in conjunction with further consultation

- any Loss Adjustment Factor <1.02 and >= 0.98 is increased/decreased to 1.00
- any Loss Adjustment Factor <1.04 is decreased to 1.02
- any Loss Adjustment Factor >=1.04 is set at 1.04

The graphs below in figure 15 depict how this method reduces the spread of data, hence reducing the Standard Deviation of the data set.

Analysis carried out indicated the following effects:

- A saw-tooth type graph was produced highlighting the difference in TLAF over day and night periods (see below Figure 18). The night peaks on these saw-tooth graphs are usually explained by the reduced amount of generation during the night time period. This type of graph is common for generators which are not generating / min stable generation at night under the banding method.
- The generating unit with the lowest TLAF over 2008 & 2009 was set between 0.96 and 1.00 and similarly the generating unit with the highest TLAF over 2008 & 2009 was set between 1.00 and 1.04 under the Banding Methodology.
- A generating unit with an approximately average TLAF with a low volatility was seen to be set to between 0.98 and 1.00. Again a Saw-tooth curve in observed highlighting the difference between Day and Night TLAF values.
- The generating unit with the highest year to year variability over a period from 05-09 shows only a small improvement. However, the 08-09 data set under the Banding TLAF Method is set between 0.960 and 1.040, again showing differences between Day and Night TLAF values.

<u>Criteria Addressed</u>

Efficient Short Term Dispatch: The banding methodology reduces the efficiency of short term dispatch as the calculated TLAFs are not applied to each generator. As the data set is less spread out and the standard deviation is also reduced, the data is therefore less reflective of the actual losses on the system.

If a TLAF is calculated as 0.91 under the normal TLAF regime it would be increased to 0.96 under the Banding Methodology. This would indicate that a number of generators with TLAFs between 0.91 and 0.96 would now be bunched all together at 0.96. The relative order between generators would be altered thus leading to a less efficient Short Term Dispatch.

Efficiency: The efficiency of the TLAFs is increased using the Banding Method. There are now minimum and maximum limits on the TLAFs which mean a generator knows that the TLAF will not go below 0.96 nor above 1.04. This should encourage efficient and appropriate investment in infrastructure. The slight reduction in volatility should also aid efficiency.

Cost Reflective: The Cost Reflectivity is reduced under the Banding Methodology. The figures are bunched into a limited number of bands. The spread of data is reduced and the range of data is reduced. Generating units incurring large amounts of losses are not penalised fully and generating units offsetting large amounts of losses will not benefit fully.

On the other hand the method retains the Locational Signal and associated Cost Reflectivity to some extent i.e. in 2009 the majority of TLAFs (ie 56% for 2009) would be allocated a TLAF of 1. A minority would be allocated the worst TLAF (ie 0.96 – 6% for 2009) and a correspondingly small portion would be allocated the best TLAF (ie 1.04 – 6% for 2009). Under this methodology it may be difficult to fully recover losses.

Volatility: The volatility of the TLAFs is addressed using this methodology. Obviously, the TLAF will alter from year to year due to new constraints on the system or new generators/demand connecting or disconnecting into different points on the system. If a generator’s TLAF is anywhere between 0.98 and 1.02 then it would be automatically be set to 1.0 and from

Graph 1&2 below, looking at 2009 TLAFs, the net result of this banding is that 88% of TLAFs are at 0.98, 1.0 or 1.02 contrasted with only 56% at 0.98 < TLAF < 1.02 under the Normal TLAF allocation.
The above cases highlight the reduction in the volatility of the TLAFs under the Banding Methodology. Multiple year volatility is reduced to a small extent, as the TLAF must take a large jump in order to move from each band and TLAFs also become slightly more predictable as a result of this. Of course a TLAF can still jump between 0.98, 1.0 and 1.02 and also from 1.04 to 0.96.

Predictability: There is a certain amount of predictability associated with this methodology. It is possible that there will be movement from band to band but the TLAF will not slide below 0.96 nor above 1.04.
Definite day/night patterns are observed under the Banding Methodology in the form of Saw-tooth graphs (see figure 18 as an example).

Transparency: The Banding Method would as transparent as the current methodology as it is simply an additional step. The TLAFs are calculated in the usual manner and then a Banding Rule is applied consistently across every generator.

<u>*Issues*</u>

As highlighted above, the main issues associated with this Methodology are:

- There is a reduction in efficient short term dispatch under this methodology due to an alteration of the relative ranking of generators.
- This method reduces the cost reflectivity of the TLAF and so it is possible that the losses are not fully recovered. Generators incurring losses on the system are not fully penalised and generators offsetting losses do not receive full benefits.
- The Banded TLAF method does not have a huge impact on multiple year TLAF variability as this is ultimately affected by the introduction and removal of generation and demand. However, it does reduce the negative or positive effects of such changes.

- An edging effect is created using this method. Within bands movement is good, however if a TLAF is on the edge of a band it could still be seen as volatile.
- Under this TLAF Methodology cross subsidisation would occur. Generators in areas off-setting losses could end up earning less as generators incurring losses would be paying less.
- In order to recover the cost of losses annually the bands may need to be altered and/or the initial TLAFs will all be reduced during the calculation.

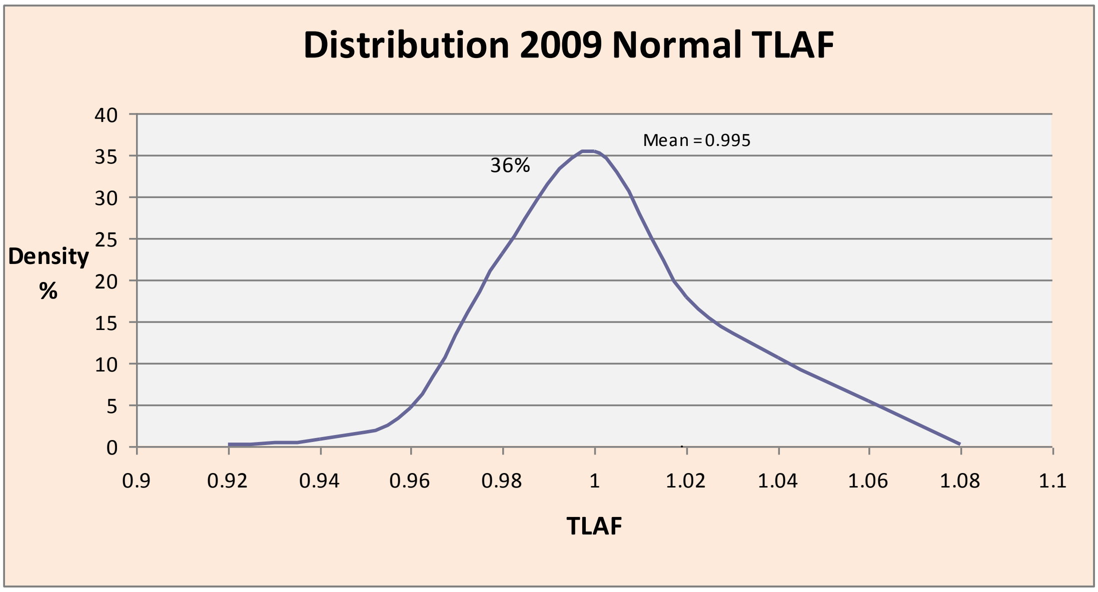


Figure 16: 2009 normal TLAF, unweighted mean 0.998, 36% of TLAFs on around the average[28]

[28] This graph depicts the actual distribution of the 2009 TLAFs (as opposed to a statistical distribution) for the purpose of a direct comparison with the 2009 Banded TLAF graph below

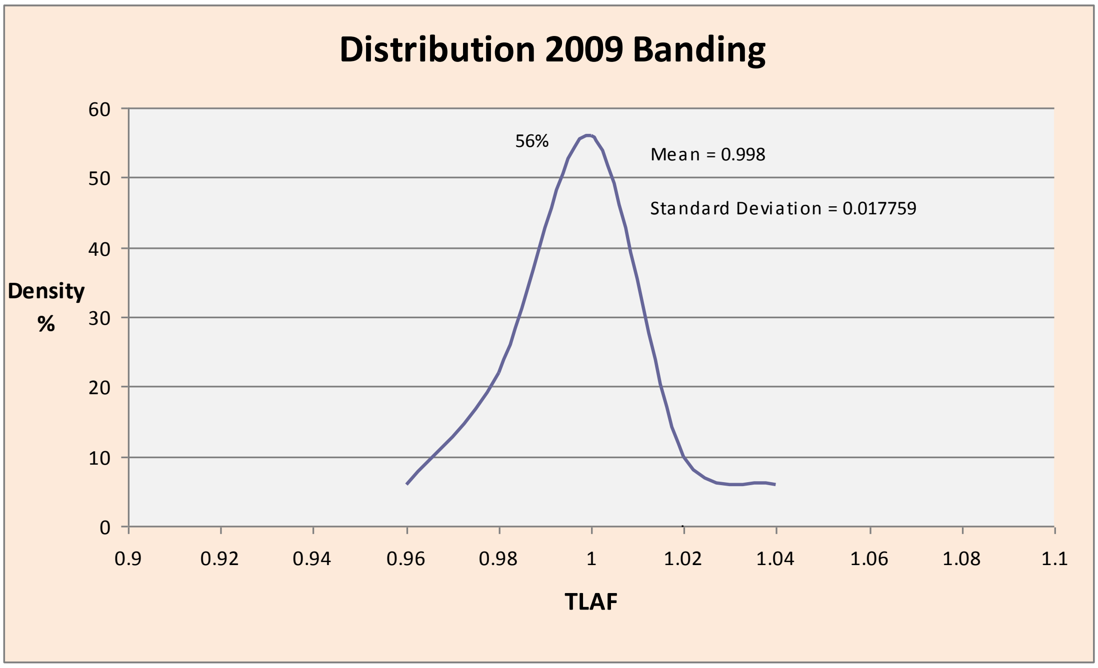


Figure 17: 2009 Banded TLAF, Unweighted Mean 0.998, 56% of TLAFs on the Average[29]

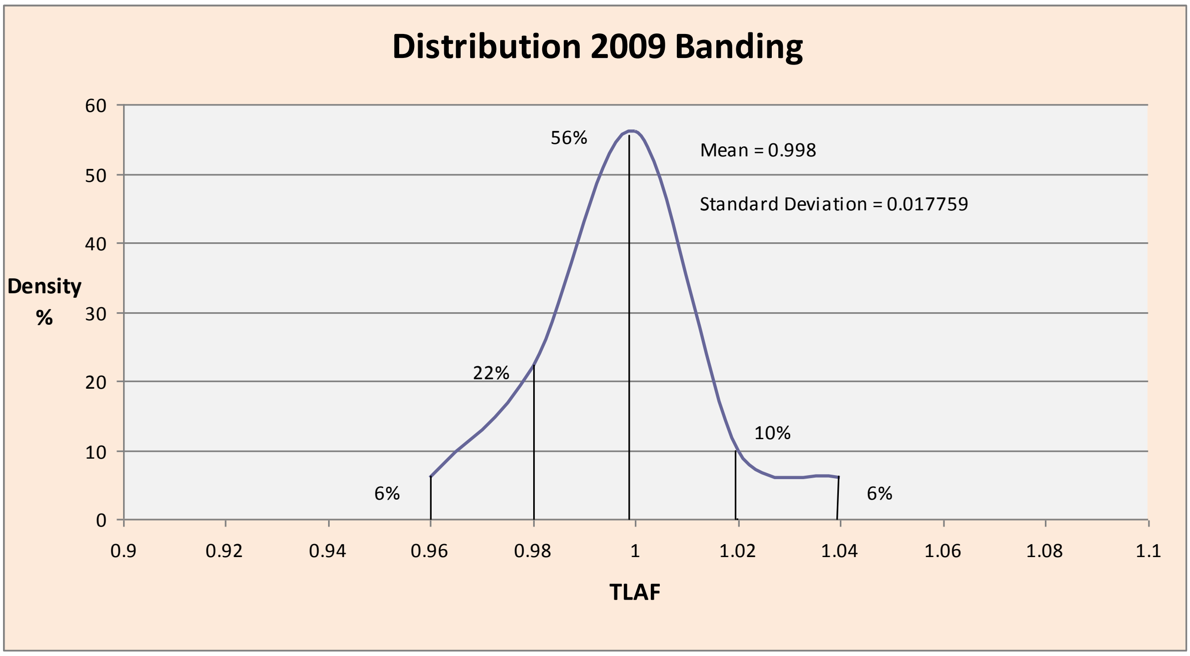


Figure 18: Banding method

[29] This Graph depicts the actual distribution of the 2009 TLAFs when the TLAFs are banded according to the bands described above.

88% of Generator TLAFs are included between the limits of 0.98 and 1.02. Under the banding method, the remaining 12% are divided between 0.96 and 1.04. The 12% provide the locational signal.

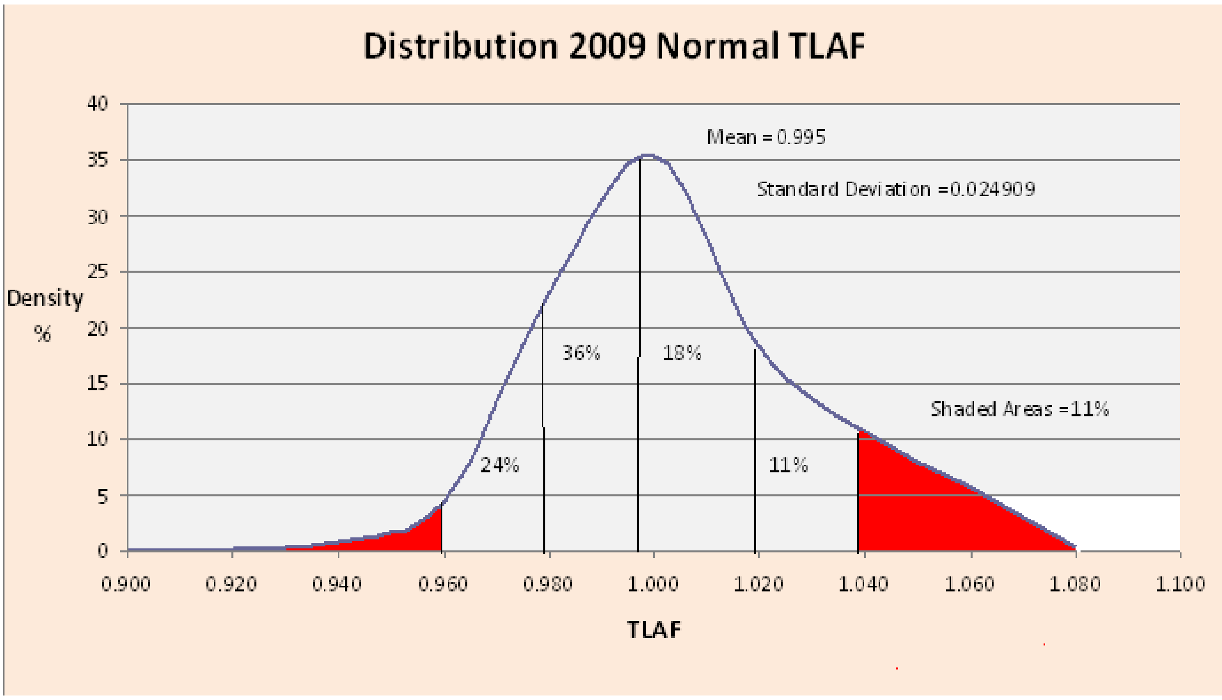


Figure 19: Normal TLAF

Under the Normal TLAF regime, 11% of TLAFs are <0.96 or >1.04 (highlighted in the shaded red areas). This 11% is the equivalent of approx 20 Generating Units. The combined MEC of all the affected units is just over 1000MW. This is a significant amount of generation capacity to be affected by Banded TLAFs in contrast to the Distribution. This may also have a large effect on the Market Schedule and should be thoroughly investigated before implementation.

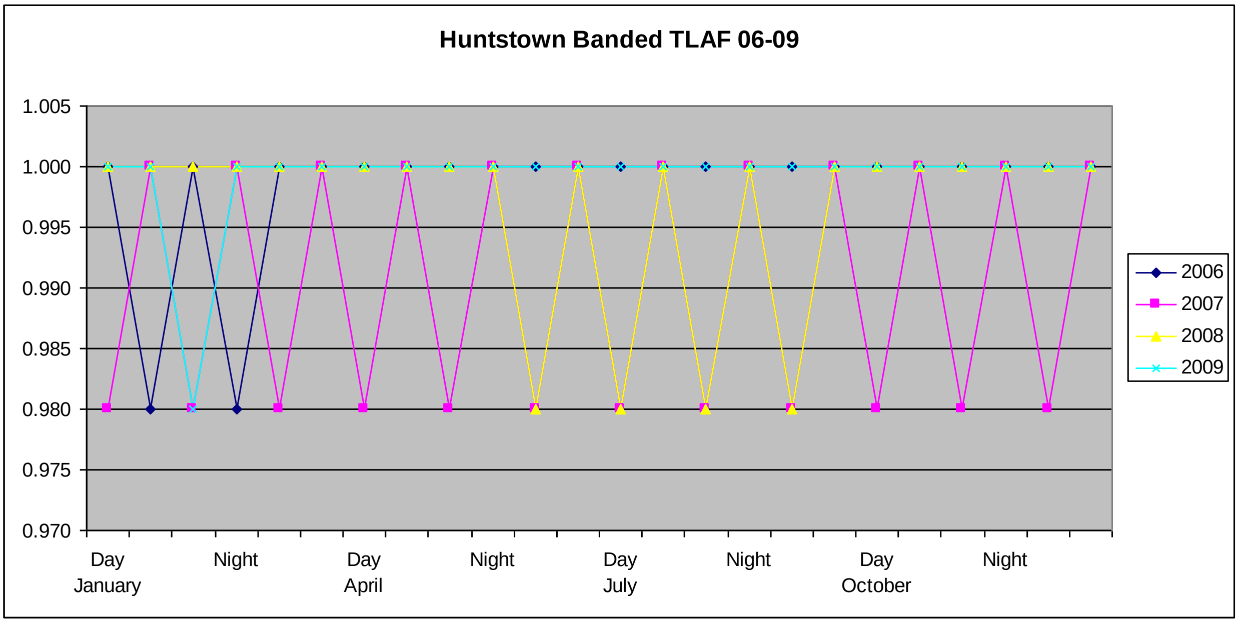


Figure 20: Saw-tooth type graph showing TLAF difference between day & night

Appendix C
Losses
Compression Factor

Implementation

The 'Compression Factor' is another possible method of reducing the volatility of the regular TLAF Methodology. All the TLAFs are squeezed/compressed by means of an algorithm. Using this algorithm the spread of data could be limited to between 0.95 and 1.05 / 0.94 and 1.04. The compression factor is relative to a fraction of the difference between the original TLAF and algorithm normalisation number. For the purposes of illustration the algorithm will be normalised around 1. It is possible that another number will be chosen which could be more representative of the actual losses on the system.

Study Method

The Study is conducted using the following algorithm:

$\mathrm{X} = \text{TLAF}$

If $\mathrm{X} <$ **1**[30], $\frac{1-\mathrm{X}}{2} + \mathrm{X}$

If $\mathrm{X} >$ **1**, $\mathrm{X} - \frac{\mathrm{X}-1}{2}$

Equation 1

It the TLAF is less than 1, then half of the difference between the TLAF and 1 is added on to the original TLAF. If the TLAF is greater than 1, then half the difference between the TLAF and 1 is subtracted from the original TLAF. The final TLAF is rounded off to the nearest decimal place. TLAFs remain in the same format i.e. 0.986.

[30] Please note that the algorithm is being normalized around 1 for the purpose of illustration. It is likely that another number could be used for this normalization subject to further consultation

- If a TLAF is 0.91 and the Compression Factor Method is applied, it will be increased by 0.045 (ie. Half the difference between the TLAF and 1) and the new TLAF will be 0.955.
- If a TLAF is 0.986 and the Compression Factor Method is applied, it will be increased by 0.007 (ie half the difference between the TLAF and 1) and the new TLAF will be 0.993.
- Finally, if a TLAF is 1.05 and the Compression Factor Method is applied, it will be reduced by 0.025 (ie half the difference between the TLAF and 1) and the new TLAF will be 1.025.

The spread of the data is reduced as indicated by a lower standard deviation; The mean of the data set is closer to 1. The algorithm naturally selects its limits. The limits selected will be half the difference between the smallest TLAF and 1, added on to the smallest TLAF. The opposite is true for the largest TLAF, half the difference between the largest TLAF and 1 will be subtracted from the largest TLAF. While the TLAFs sit between 0.9 and 1.1 and the normalisation figure is 1 – the limits will be 0.95 and 1.05[31].

The effects of the volatility are reduced by approximately 50%. To illustrate:

2009 TLAF	2009 Compression Factor TLAF	2010 TLAF	2010 Compression Factor TLAF
0.951	0.976	0.982	0.991

Table 16: Comparison of 2009 & 2010 TLAF with Compression TLAF

Under the regular TLAF regime the TLAF increases from 0.951 to 0.982 (increase of 0.031). Under the Compression Factor the TLAF will now go from 0.976 to 0.991 (increase of 0.015). Therefore, in this particular example the effects of the TLAF volatility have been reduced by approximately 50%. Subject to sensitivity analysis, these figures may change (it is likely that the normalisation figure will change to reflect estimated losses and also full losses must be recovered by the methodology) but the illustration is useful in explaining the principle.

[31] Based on historical data, it is unlikely that a TLAF will deviate from 0.9-1.1

<u>*Criteria Addressed*</u>

Efficient Short Term Dispatch: The Compression Factor Methodology will reduce the efficiency of the Short Term Dispatch given that the underlying TLAFs have been manipulated to reduce the data spread. However, the relative order remains the same. If the order remains the same then the least 'loss incurring' generator will be dispatched ahead of a more 'loss incurring' generator. Therefore, if a generating unit receives a TLAF of 0.92 and another receives a TLAF of 0.93 – under the Compression Factor method it is accurately reflected that the first generator is incurring more losses than the second.

Efficiency - It is important to note here that a reduction in volatility and an increase in predictability leads to a reduction in investment risk. If a generator knows that its TLAF will not be greater or less then predefined limits, it is envisaged that the cost of capital for investment purposes would be reduced. This reduction would aid future infrastructure investment. The Compression Factor Methodology results in a small increase in predictability and a large jump in reduction of volatility whilst maintaining an efficient dispatch. All these factors lead to an increase in efficiency.

Cost Reflective: The Cost Reflectivity is reduced to an extent under the Compression Factor Methodology. The figures are essentially squeezed towards 1 in both directions. The spread of data is reduced and the range of data is reduced. Generating units incurring large amounts of losses are not penalised fully and generating units offsetting large amounts of losses will not benefit fully.
On the other hand the method retains the Locational Signal and associated Cost Reflectivity to some extent as the generators with the lowest Compression Factor will still be incurring the most losses on the system on the system and vice versa, i.e. the relative order is maintained.

Volatility: The volatility of the TLAFs is addressed using this methodology. Obviously, the TLAF will alter from year to year due to new constraints on the system or new generators/demand connecting/disconnecting into different points on the system. Using the compression factor and squeezing all the loss factors towards 1, incrementally, removes approximately 50% of the effects of the volatility of the TLAFs (as described above). There is a guarantee that all loss factors will stay within certain limits (in the studied examples the limits will be 0.95 – 1.05 while the regular TLAFs are between 0.9 and 1.1 however this is subject to change). Graphs 3 & 4 demonstrate how the current method addresses the volatility at Meentycat. Graph 3 shows a regular TLAF allocation from 07-09 and Graph 4 depicts the Compression Factor Method allocation from 07-09. Graph 5 emphasises the limits selected by the algorithm.

Year-on-Year Volatility: It is important to emphasise that TLAFs will still change as a result of their location and it is possible for a TLAF to move between 1.1 and 0.90 (worst case example) over years , the effects of this volatility will be reduced however. Under the compression factor methodology, using an algorithm normalised around 1, the generator loss factor will now move from 1.05 to 0.95.

Predictability: The increase in the predictability of TLAFs under this methodology is only due to the limits which it imposes on the TLAFs. The unpredictability of the underlying methodology is still applicable.

Transparency – The Compression Factor Method would be as transparent as the current methodology. The underlying TLAFs are calculated in the usual manner and then a Compression Rule in the form of the Algorithm above is applied consistently across every generator.

Issues

As highlighted above, the main issues associated with this Methodology would be:

- There is a slight reduction in efficient short term dispatch under this methodology.
- This method reduces the cost reflectivity of the TLAF. Generators incurring losses on the system are not fully penalised and generators offsetting losses do not receive full benefits.
- Further study is required to determine the full effects of this methodology on the Market and Dispatch Schedules. The method is basically a manipulation of actual computed data to dampen the effects on generators. It is important to fully understand how this will affect the Market, Dispatch Schedules and the recovery of Losses on the Network. In recovering the losses the algorithm may be altered, however the principles will remain the same. A sensitivity analysis will be compiled to describe the effects of this methodology.

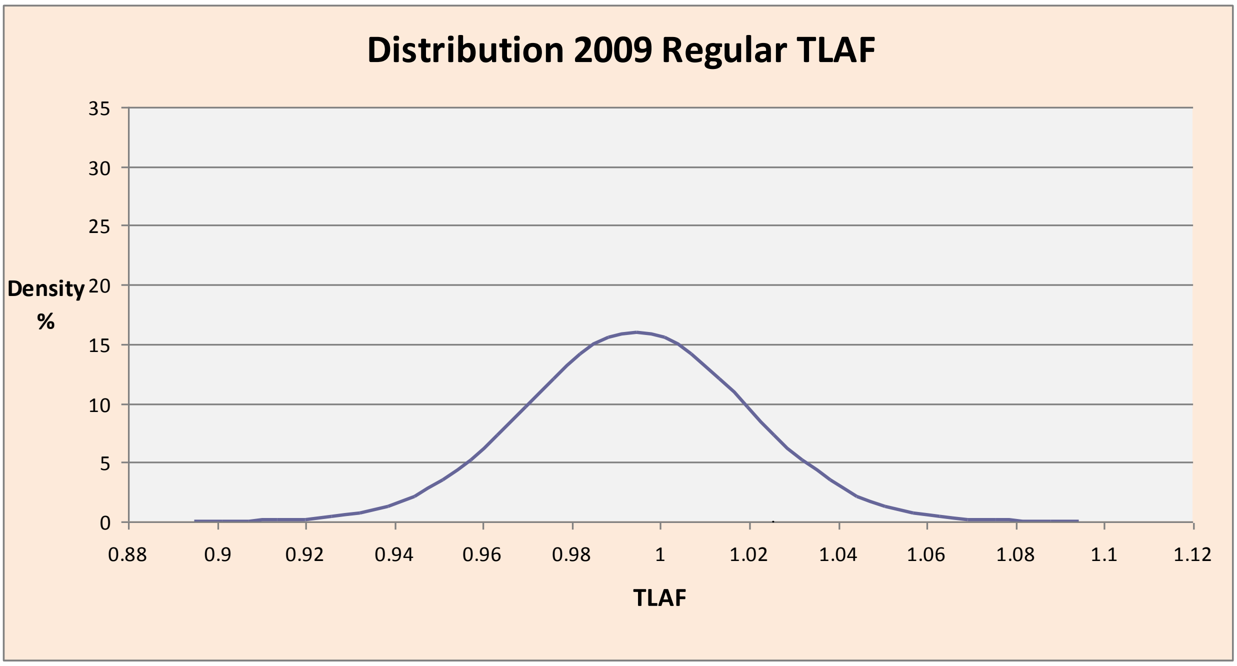


Figure 21 – 2009 Normal TLAF, Unweighted Mean 0.995, Statistical Model of the Normal Distribution estimating 16% of TLAFs on the Average

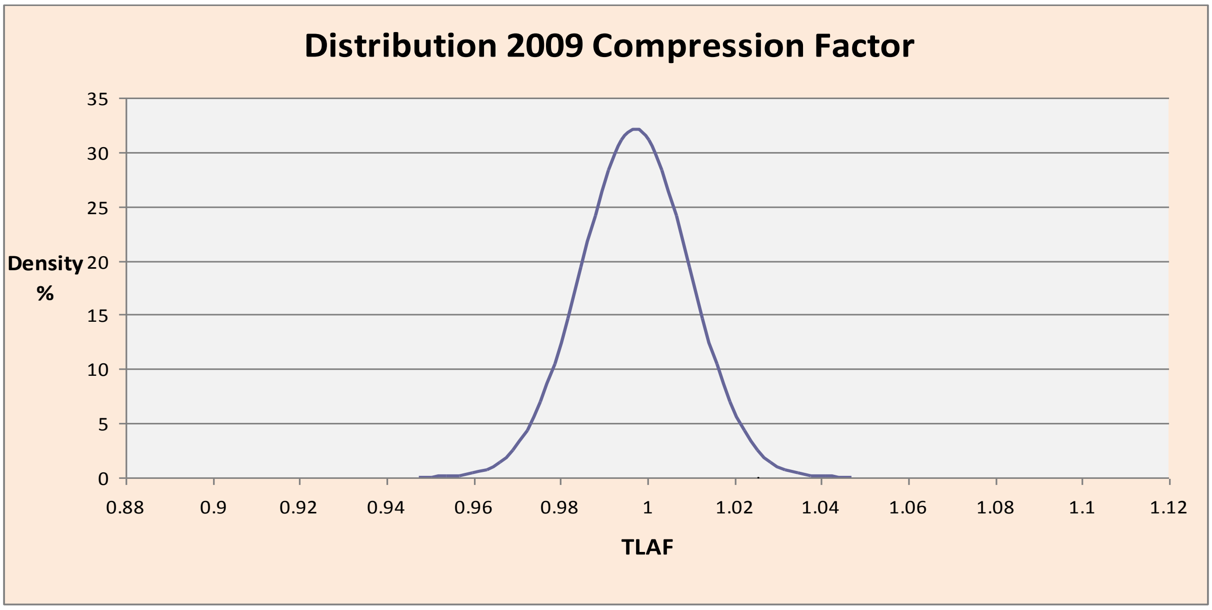


Figure 22 – 2009 Compression Factor, Unweighted Mean 0.997, Statistical model of the Normal Distribution estimating 32% of TLAFs on the Average, Reduced Data Spread

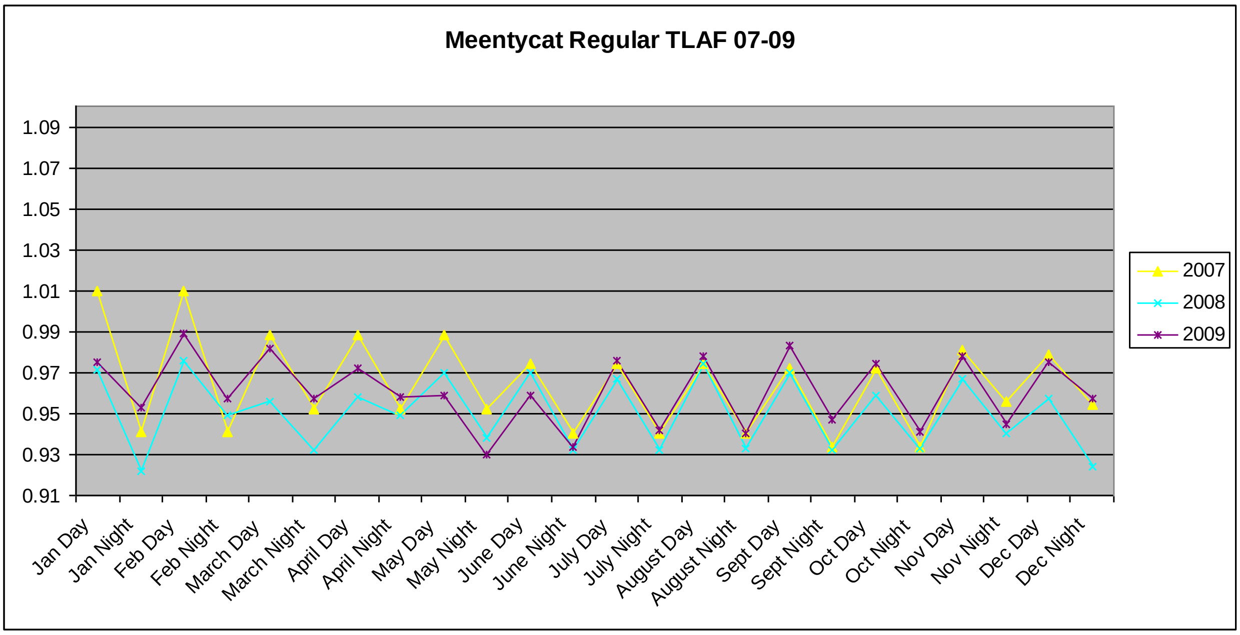


Figure 23 – Regular Meentycat TLAF 07-09

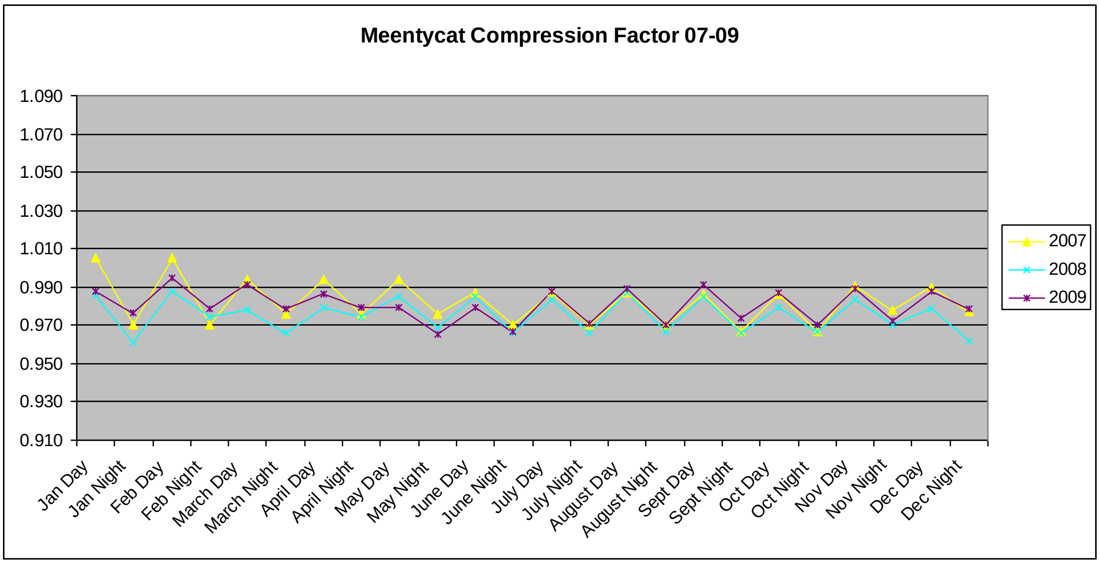


Figure 24 – Meentycat Loss Factor after Compression Factor Method has been applied (07-09)

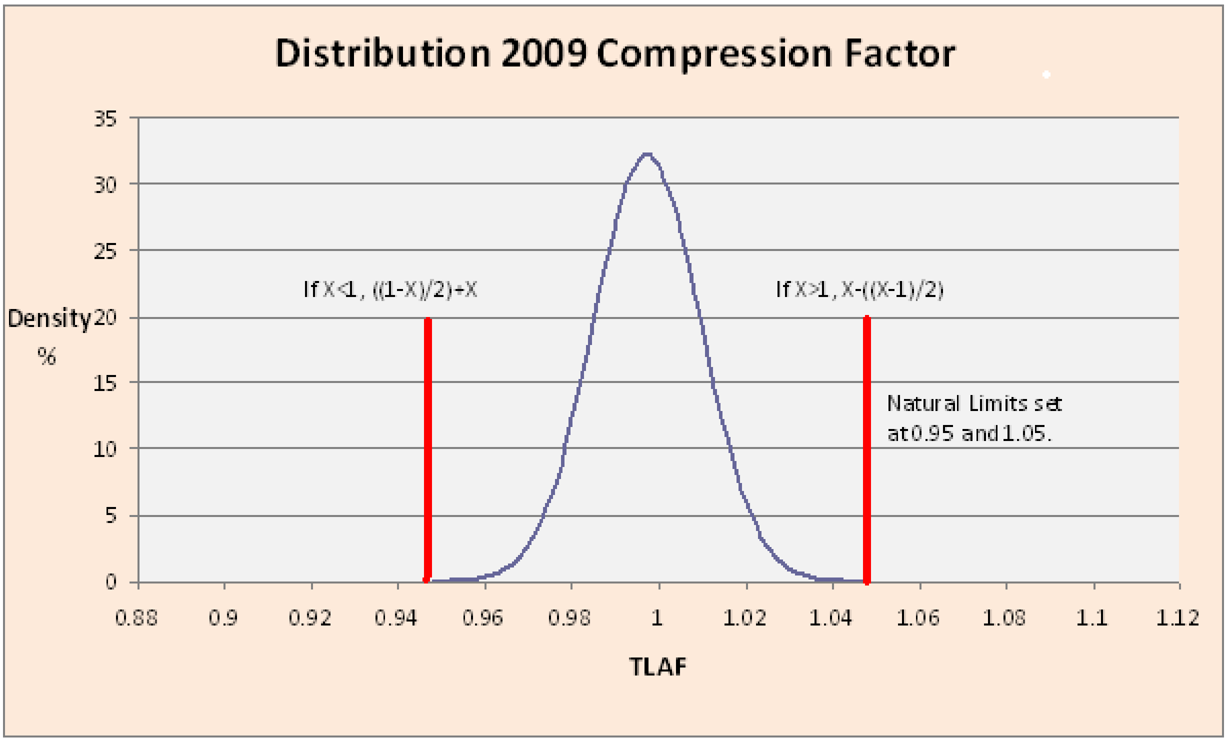


Figure 25 – Graph showing the Normal Distribution of TLAF with Compression Factor algorithm normalised around 1 – (0.95 <= TLAF <= 1.05 under Compression Factor Methodology). Limits are self-setting. Based on historical data the loss factor will not fall below these figures.

Appendix D
Zonal Losses

Implementation

A comprehensive survey has been carried out on Zonal Losses Adjustment Factors. Two methods were chosen in order to Zone the different areas of the All-Island Network.

1. Using the current Gate-3 Zonal Methodology
2. Using the Planet[32] Database Zoning Methodology planning zones assumed by EirGird

Both zonal methodologies are similar. Option 1 is loosely based on Option 2 and so Option 2 was used as base case. A number of zones from the Database were chosen for analysis. All the generators within a particular zone are studied as per published TLAFs for 2008 and 2009 and also Indicative TLAFs for 2011. Indicative TLAFs for 2011 are included in this study to highlight the additional generators expected to connect to the system between 2008 and 2011. The un-weighted average TLAF is taken from each selected zone and allocated to everyone within that zone.

Zones were defined based on zones used in power system planning studies

Key:

Area 4	West of Ireland
Area 5	South Midlands
Area 6	South East
Area 8	Midlands
Area 11	North

Table 17: List of Areas

[32] Planet is a Power System Database run through Access to aid Power System Planning (Planning Zones are zones pre-defined by Eirgrid)

Study Description

Using the Zonal methodology for allocating TLAFs to generators simply rounds a number of generators into a group, takes the un-weighted average TLAF of that group and allocates this TLAF to the whole group over each period.

The study was carried out on a number of different zonal areas. Taking Area 4 (which is the mid-West area of the country), as an example, and looking at data figures over 2008, 2009 and also 2011 a number of statements can be made (see the detailed study on Area 4 below).

Criteria Addressed

Short Term Efficient Dispatch: It appears that the Zonal Method would not support efficiency in the Short Term Dispatch as it is an average of a number of generator within a zone with TLAFs possibly ranging from 0.967 (Min Zone 5 2009) and 1.098 (Max Zone 5 2009). The locational signal is 'diluted' by taking an average of all the generators in a zone. Therefore, a generator with a very 'bad' TLAF in one zone could be dispatched ahead of a generator in a different zone with a very 'good' TLAF. This would almost certainly result in an increase in inefficiencies in the Short Term Dispatch and would reduce cost reflectivity e.g. Area 4: if the Maximum TLAF was reduced to the Average TLAF i.e. 1.016 to 0.983 – then the fact that the Generator was situated in a "good" location would be essentially ignored.
Allocating an average day and night TLAF under the Zonal Methodology would not support short term efficient dispatch.

Efficiency – The Zonal Method would not support efficiency of the network in the long-term. An inaccurate locational signal would be sent out to generators. The Zonal Method for TLAF allocation would not drive efficient network build.

Zones can cover large areas also which could include a large amount of generators. At the extremes of zones the range of TLAF could be very high and averaging this out would again potentially lead to higher inefficiencies. Also cross-subsidisation would occur where generators off-setting losses would compensate for generators incurring losses.

Cost Reflectivity: The Zonal Methodology is the least cost reflective of all the methods studied. This methodology will lead to cross subsidization with generators in 'good' locations paying for the losses incurred by generators in 'bad' locations. The spread of data is decreasing from 2008 to 2011 in Area 4 as can be seen from graphs 6, 7 and 8 below, however even in 2011, the range is still 0.06 – which is relatively high.
With such a gap between the maximum and minimum TLAF in a particular year, taking an average for a group of generators could not be cost reflective in terms of losses. Also, from the detailed study below, only approx 20% of TLAFs are found to be around the average – this is very low and indicates again that since the average TLAF is being applied it could not be cost reflective.

Volatility: The volatility of the TLAF will be less under this approach. New TLAFs will be absorbed by taking the average of a large group of generators. If sizeable amounts of generation locate in a particular zone the volatility would be reduced but this would not be a regular occurrence. However, large numbers of small units with individual TLAFs connecting into a zone could also change the average and hence affect the volatility and this will be seen in a few cases as a result of Gate 3.

Predictability: As per responses to the original consultation paper TLAF predictability was identified as being an important criterion. The Zonal Method is predictable in that the Areas will be set and will not change on an annual basis. As the TLAF will be an average of the generators in the area, the volatility will be reduced. However, if a number of new generators were to locate in the particular area then the mean would be increased/decreased accordingly.

Transparency: The Zonal Method is basically an additional step on to the current TLAF Methodology. The methodology at the moment is actually slightly less transparent than the current methodology. The criteria for allocating particular zones can be subjective and the Zonal Areas chosen for the studies are pre-defined. It should also be noted that the criteria used to select zonal areas were not selected with losses in mind. It would be very difficult to assign zones with losses as a contributory factor and ensure that the method is non-discriminatory.

Issues with the Method

As described above the issues with this Methodology are:

1. The methodology is one of the least cost reflective options and neither does it support efficiency nor short term efficient dispatch.
2. The criteria for defining the different zones are pre-defined. If new zones were selected the criteria could be very subjective.
3. The Zones can cover very large areas. TLAF range between the extremes of the area could be very large (e.g 2009 Area 4 Min (0.956) and Max (1.044)). Taking an average of these TLAFs removes the locational signal to some extent.
4. Taking an Average of the TLAFs in a Zone tends towards a less efficient short-term dispatch as described.
5. It is likely that under this methodology the cost of losses will not be fully recovered and additional analysis should be carried out in order to investigate the results of applying this methodology.

2011 Zonal TLAFs					
Area Name	**Planet Area 4**	**Planet Area 5**	**Planet Area 6**	**Planet Area 8**	**Planet Area 11**
Annual Average	0.983	1.037	1.027	1.011	1.002
Max TLAF	1.016	1.098	1.080	1.031	1.031
Min TLAF	0.956	0.967	1.001	0.963	0.957

Table 18: Example of Zonal TLAF Study

Detailed Zonal Study

Area 4 - 2011[33]

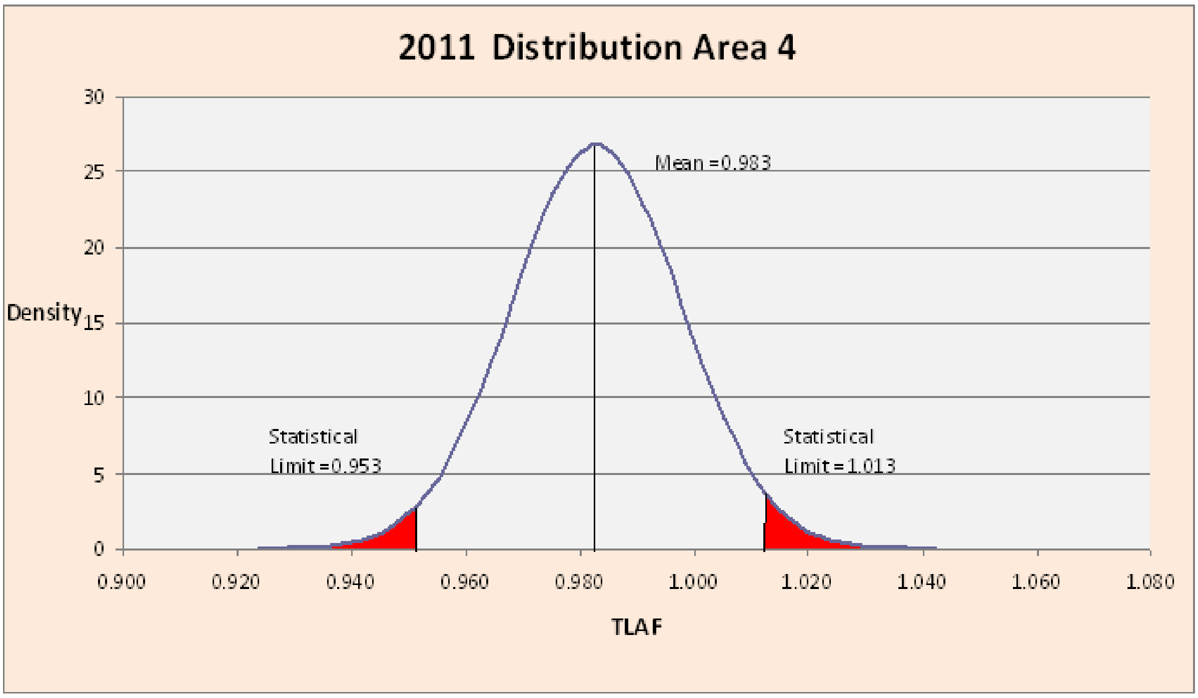


Figure 26 – Graph showing Statistical Distribution of Area 4 – 2011

98% of the TLAF Values for Area 4 in 2011 are within 2 standard deviations of the mean (σ.)[34] Standard Deviation = 0.015

Max TLAF – 1.016

Min TLAF – 0.956

• Booltiagh	• Ardnacrusha
• Moneypoint	• Derrybrien
• Tynagh	• Ballymurtagh
• Tullabrack	• Agannygal
• Oldstreet	• Drumline
• Ennis	

Table 19: List of Generators in Area 4

[33] Please note that 2011 Figures are Indicative

[34] The standard deviation σ (sigma) is used here to describe the average difference of each TLAF from the mean TLAF. In Statistics it is expected that approximately 95% of values will lie inside 2 Standard Deviations from the mean.

Area 4 - 2009

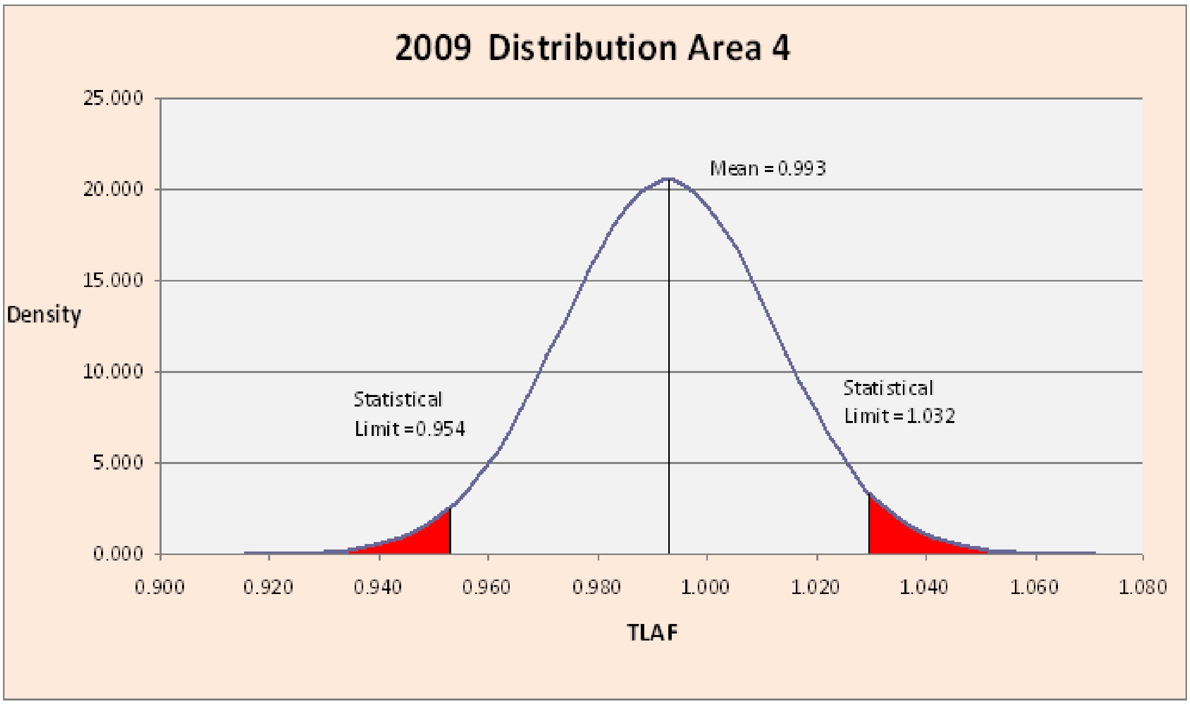


Figure 27: *Graph showing Statistical Distribution of Area 4 - 2009*

92% of the TLAF Values for Area 4 in 2009 are within 2 σ.

Standard Deviation = 0.020

Max TLAF – 1.044

Min TLAF – 0.959

• Booltiagh	• Moneypoint
• Ardnacrusha	• Derrybrien
• Tynagh	• Tullabrack

Table 20: List of Generators in Area 4

Area 4 - 2008

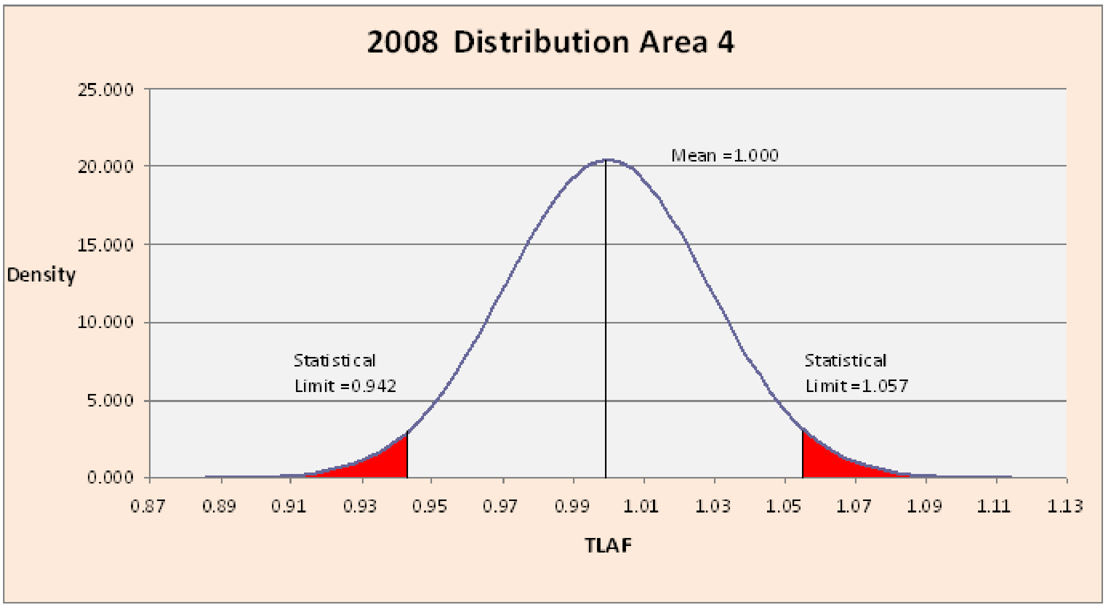


Figure 28 – Graph showing Statistical Distribution of Area 4 - 2008

A list of the generators in Area 4 is given in Table 20.

97% of the TLAF Values for Area 4 in 2009 are within 2 σ.

Standard Deviation = 0.03

Max TLAF – 1.071

Min TLAF – 0.956

Generator TLAFs – Area 4	2008	2009	2011
Min	0.956	0.959	0.956
Max	1.071	1.044	1.016

Table 21: Comparison of TLAFs for 2008/9/10.

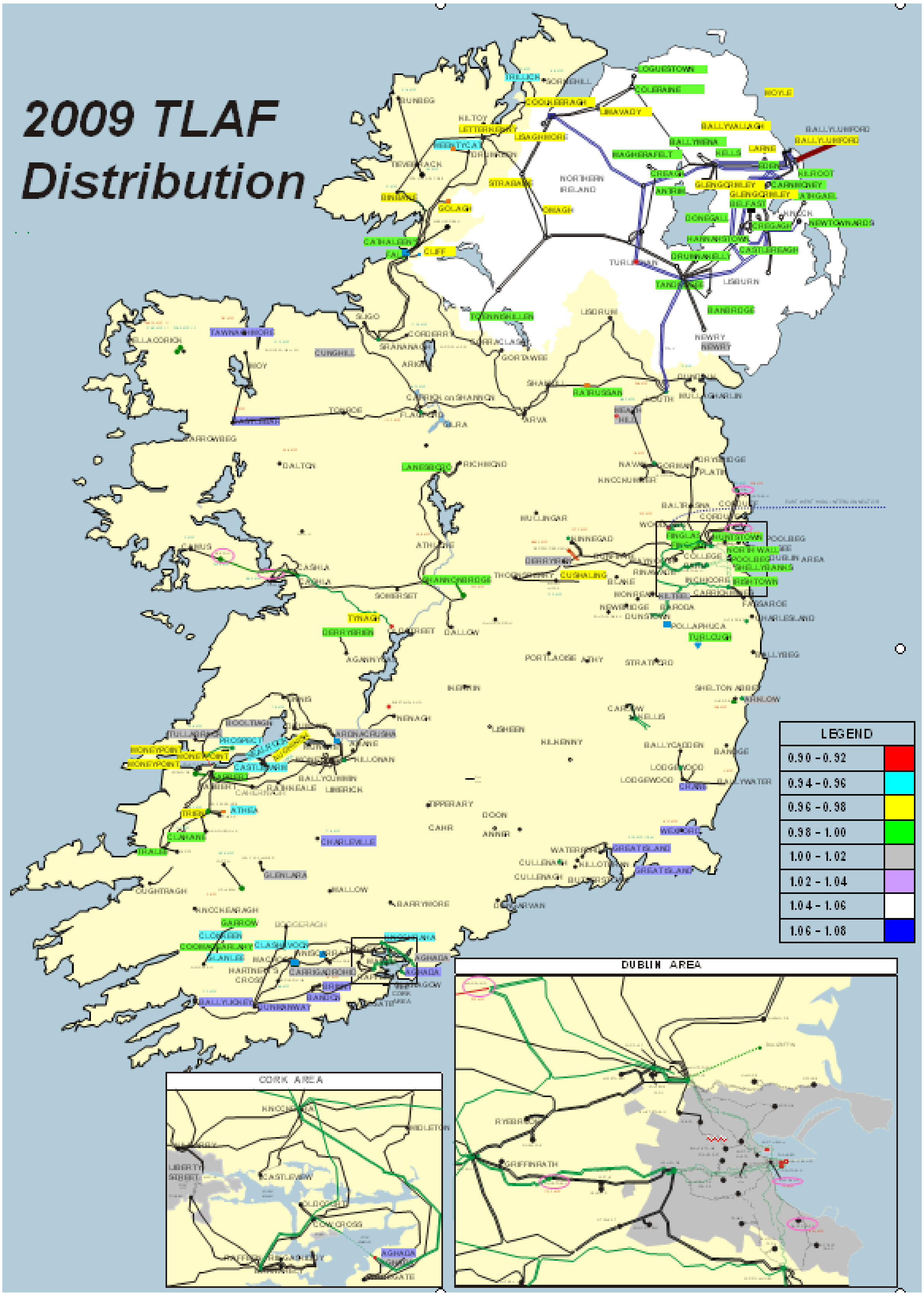
In 2011 27% of TLAFs are to be found statistically on the annual mean[35] value for Zone / Area 4. In 2009 20% of TLAFs are statistically found on the annual mean value. In 2008 20% of TLAFs are found statistically on the mean value.

[35] Mean Value is an unweighted average of Generator TLAFs in Area 4 in 2011, 2009 and 2008

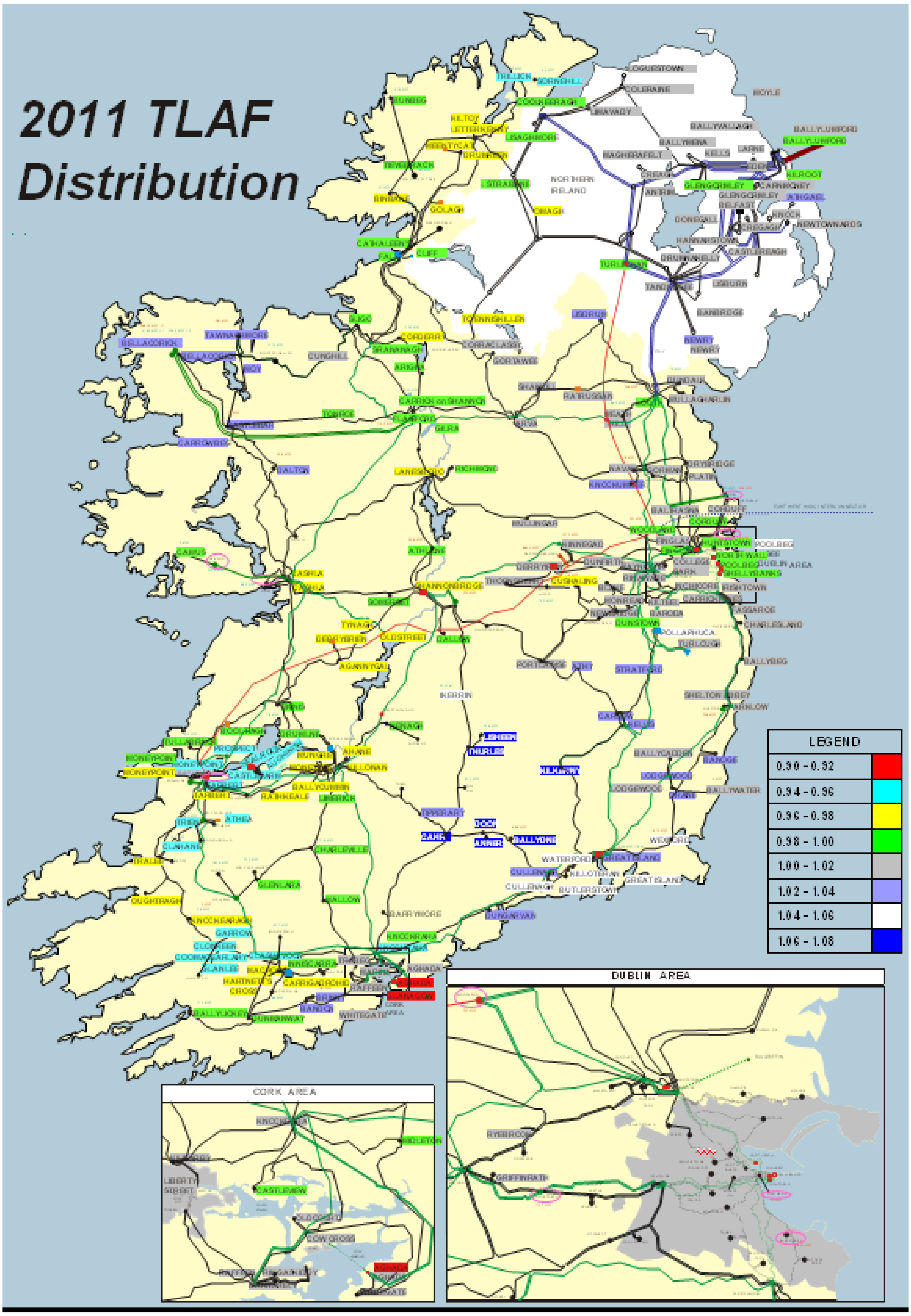
The range of data is reducing from 2008 to 2011, with a range of 0.06 in 2011.

The Standard Deviation is also decreasing from 0.03 in 2008 to 0.015 in 2011. This is in line with the extra number of generators connected to the system in 2011.

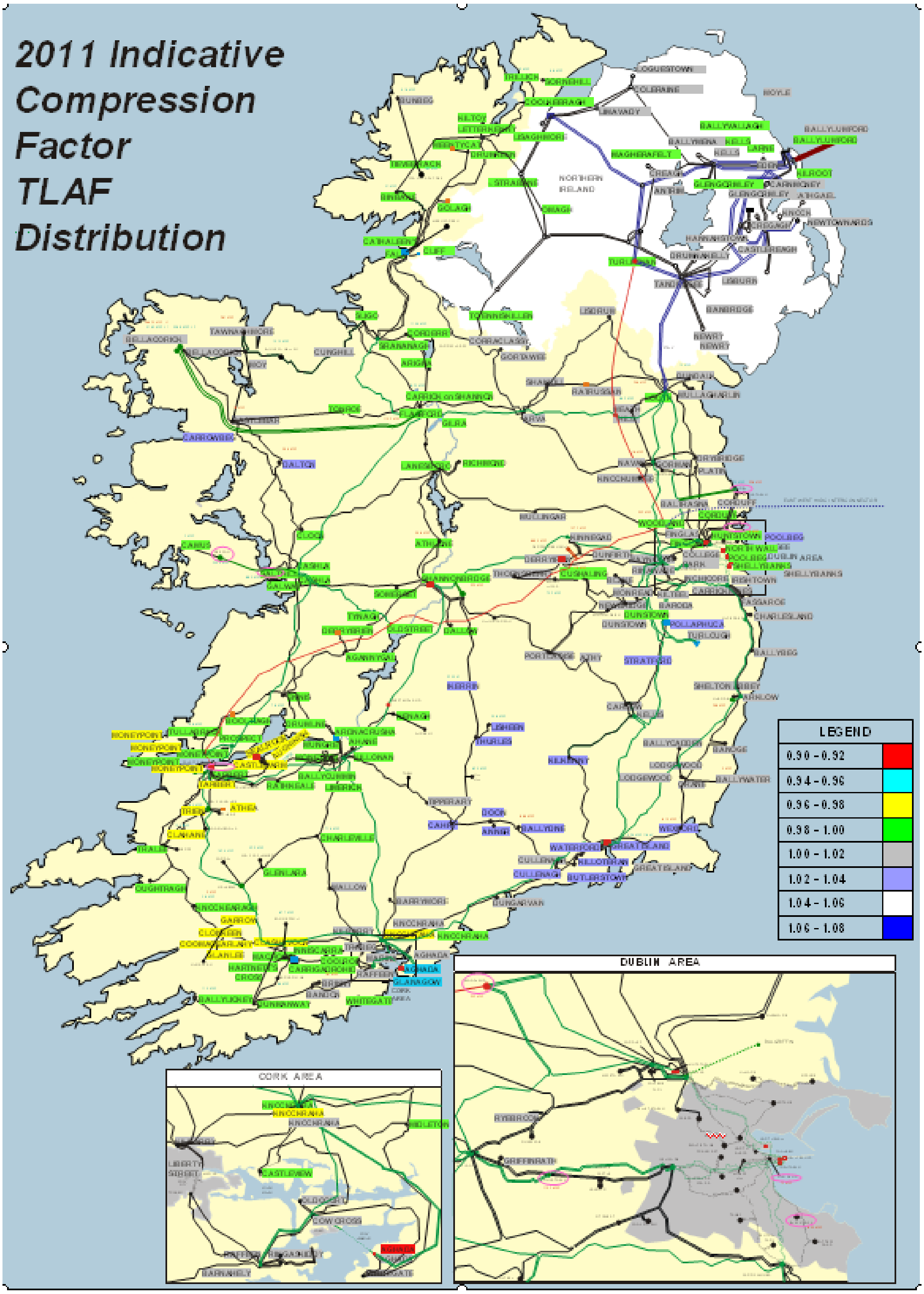
Appendix E
TLAF Distribution



Map 1 – All Island Map showing 2009 Regular TLAF Distribution



Map 2 – All Island Map showing Indicative 2011 Regular TLAF Distribution



Map 3 – All Island Map showing Indicative 2011 Compression Factor TLAF Distribution

Appendix F
Rolling Average Losses Indicatives

2009 Rolling Average Indicative TLAFs																								
	January		February		March		April		May		June		July		August		September		October		November		December	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Huntstown 1	0.981	0.991	0.979	0.991	0.978	0.988	0.977	0.986	0.981	0.990	0.977	0.990	0.978	0.990	0.979	0.990	0.978	0.989	0.983	0.996	0.985	1.000	0.985	0.998
Tynagh	0.958	0.966	0.957	0.965	0.961	0.969	0.968	0.972	0.968	0.971	0.968	0.974	0.969	0.975	0.969	0.974	0.967	0.972	0.965	0.973	0.960	0.969	0.959	0.968
Marina	1.053	1.057	1.054	1.059	1.055	1.058	1.058	1.060	1.059	1.058	1.069	1.050	1.066	1.047	1.058	1.047	1.055	1.044	1.045	1.032	1.047	1.040	1.045	1.044
Rhode	1.004	1.006	1.003	1.005	1.001	1.003	0.998	1.002	1.001	1.003	0.999	1.004	0.998	1.003	1.001	1.004	0.998	1.000	1.003	1.006	1.007	1.011	1.006	1.009
Aghada	1.039	1.045	1.040	1.047	1.042	1.048	1.042	1.049	1.044	1.047	1.056	1.040	1.056	1.041	1.047	1.040	1.042	1.037	1.036	1.026	1.038	1.032	1.036	1.036
Meentycat	0.985	0.939	0.992	0.949	0.975	0.947	0.973	0.953	0.972	0.940	0.968	0.935	0.972	0.938	0.975	0.938	0.975	0.938	0.968	0.936	0.975	0.947	0.970	0.945
Enniskillen	1.019	0.991	1.020	0.990	1.014	0.991	1.004	0.990	0.997	0.993	0.996	0.988	0.985	0.983	0.986	0.982	0.994	0.986	0.997	0.989	1.002	0.990	1.006	0.987
Ardnacrusha	1.013	1.013	1.015	1.018	1.024	1.025	1.033	1.032	1.034	1.030	1.044	1.024	1.043	1.022	1.039	1.023	1.032	1.018	1.018	1.004	1.010	1.005	1.008	1.005
Ratrussan	1.001	0.988	1.003	0.989	1.000	0.987	0.993	0.989	0.992	0.981	0.992	0.981	0.990	0.985	0.991	0.979	0.994	0.983	0.997	0.989	1.002	0.988	1.002	0.989
Booltiagh	1.014	1.011	1.015	1.015	1.022	1.019	1.030	1.023	1.029	1.021	1.036	1.014	1.036	1.013	1.032	1.014	1.026	1.011	1.016	1.001	1.011	1.003	1.008	1.006
Ballywater	1.044	1.034	1.043	1.036	1.037	1.029	1.034	1.025	1.036	1.025	1.034	1.019	1.029	1.018	1.029	1.019	1.032	1.019	1.034	1.022	1.042	1.033	1.041	1.035
Coomagearlahy 1	1.014	1.019	1.015	1.022	1.020	1.022	1.028	1.026	1.027	1.023	1.034	1.015	1.029	1.010	1.023	1.011	1.014	1.004	1.003	0.989	0.998	0.992	1.000	1.001
Clahane Wind Farm	1.006	1.003	1.006	1.007	1.000	1.004	1.015	1.006	0.995	0.991	1.005	0.987	0.998	0.981	1.018	1.013	1.007	1.000	0.988	0.974	0.978	0.978	0.977	0.986
Coomacheo Wind F	1.023	1.011	1.025	1.016	1.019	1.014	1.032	1.014	1.012	1.003	1.034	1.015	1.025	1.009	1.016	1.009	1.009	0.996	0.990	0.972	0.985	0.977	0.989	0.990
Dublin Bay Power	0.983	0.994	0.982	0.993	0.980	0.991	0.979	0.989	0.983	0.993	0.981	0.993	0.982	0.993	0.983	0.994	0.983	0.993	0.987	0.999	0.990	1.003	0.990	1.001
Derrybrien	0.992	0.985	0.993	0.988	0.997	0.990	1.003	0.995	0.999	0.991	1.007	0.987	1.012	0.994	1.006	0.988	1.002	0.985	0.995	0.978	0.990	0.979	0.989	0.982
Edenderry	0.961	0.949	0.957	0.944	0.959	0.948	0.952	0.947	0.959	0.949	0.957	0.946	0.985	0.977	0.976	0.964	0.978	0.965	0.981	0.969	0.970	0.955	0.968	0.952
Cliff	0.985	0.957	0.990	0.967	0.985	0.972	0.985	0.979	0.988	0.971	0.985	0.968	0.988	0.971	0.991	0.970	0.986	0.969	0.979	0.965	0.981	0.971	0.975	0.965
Cathleen's Falls	0.987	0.959	0.992	0.969	0.986	0.973	0.987	0.980	0.989	0.971	0.985	0.969	0.989	0.972	0.991	0.971	0.987	0.969	0.980	0.965	0.983	0.972	0.977	0.966
Great Island	1.039	1.039	1.039	1.040	1.036	1.037	1.035	1.035	1.036	1.035	1.038	1.031	1.040	1.031	1.038	1.032	1.038	1.031	1.039	1.030	1.044	1.039	1.042	1.040
Glanlee Wind Farm	1.012	1.013	1.014	1.018	1.016	1.021	1.027	1.027	1.027	1.023	1.034	1.015	1.028	1.010	1.022	1.011	1.014	1.004	1.003	0.989	0.998	0.992	1.000	1.001
Barnesmore Wind	0.976	0.949	0.985	0.965	0.976	0.959	0.975	0.970	0.977	0.953	0.977	0.953	0.983	0.956	0.987	0.956	0.986	0.959	0.975	0.955	0.980	0.961	0.975	0.957
Huntstown 2	0.980	0.990	0.978	0.988	0.979	0.988	0.978	0.986	0.985	0.993	0.976	0.989	0.977	0.989	0.978	0.989	0.977	0.987	0.981	0.995	0.983	0.998	0.983	0.996
Kingsmountain	1.030	1.002	1.033	1.005	1.025	1.004	1.026	1.005	1.022	1.001	1.010	0.994	1.014	0.993	1.016	0.996	1.018	0.997	1.015	0.995	1.018	1.001	1.015	1.002
Lee (ESB)	1.042	1.049	1.044	1.053	1.049	1.053	1.052	1.056	1.053	1.053	1.064	1.043	1.059	1.040	1.052	1.039	1.046	1.036	1.035	1.022	1.033	1.028	1.029	1.032
Liffey (ESB)	1.018	1.021	1.018	1.022	1.019	1.018	1.019	1.019	1.020	1.016	1.022	1.014	1.027	1.019	1.027	1.016	1.028	1.017	1.028	1.018	1.027	1.026	1.025	1.026
Lough Ree Power (	0.995	0.979	0.994	0.980	0.992	0.976	0.996	0.983	0.993	0.976	0.995	0.976	0.996	0.980	1.000	0.980	1.009	0.988	1.000	0.981	0.996	0.977	0.993	0.979
Moneypoint (ESB)	0.964	0.975	0.962	0.974	0.969	0.979	0.976	0.984	0.976	0.984	0.980	0.986	0.982	0.987	0.981	0.987	0.975	0.982	0.972	0.977	0.967	0.974	0.965	0.974
North Wall (ESB)	0.983	0.993	0.981	0.992	0.979	0.990	0.979	0.988	0.983	0.992	0.978	0.991	0.979	0.991	0.980	0.991	0.979	0.990	0.984	0.997	0.986	1.001	0.986	0.999
Poolbeg (ESB)	0.986	0.996	0.984	0.995	0.982	0.993	0.982	0.991	0.986	0.995	0.983	0.995	0.984	0.995	0.985	0.995	0.985	0.994	0.990	1.001	0.992	1.005	0.992	1.003
Rhode PCP (ESB)	1.004	1.006	1.003	1.005	1.001	1.003	0.998	1.002	1.001	1.003	0.999	1.004	0.998	1.003	1.001	1.004	0.998	1.000	1.003	1.006	1.007	1.011	1.006	1.009

	January		February		March		April		May		June		July		August		September		October		November		December	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Seal Rock	0.976	0.982	0.976	0.983	0.989	0.993	1.000	1.000	0.999	0.996	1.007	0.990	1.005	0.989	1.004	0.993	0.995	0.985	0.981	0.968	0.972	0.967	0.971	0.971
Tarbert (ESB)	0.978	0.992	0.978	0.993	0.992	1.001	1.006	1.010	1.006	1.009	1.012	1.003	1.010	1.000	1.006	1.002	0.999	0.996	0.986	0.979	0.976	0.977	0.973	0.981
Tawnaghmore PCP	1.063	1.027	1.066	1.030	1.056	1.027	1.057	1.025	1.049	1.020	1.036	1.014	1.046	1.011	1.049	1.016	1.052	1.018	1.049	1.015	1.055	1.027	1.049	1.029
Turlough Hill	0.985	1.000	0.983	0.999	0.982	0.996	0.981	0.994	0.984	0.998	0.983	0.998	0.985	0.999	0.985	0.999	0.984	0.999	0.988	1.003	0.990	1.007	0.990	1.002
West Offaly Power	0.992	0.987	0.992	0.988	0.994	0.989	0.997	0.992	0.997	0.989	1.001	0.988	1.011	1.000	1.002	0.991	0.998	0.986	0.996	0.983	0.993	0.983	0.992	0.987
Arklow Banks	1.000	1.007	0.999	1.007	0.996	1.004	0.995	1.001	0.998	1.004	0.997	1.004	0.997	1.003	0.998	1.004	0.998	1.003	1.003	1.008	1.006	1.014	1.007	1.014
Arthurstown Landf	1.011	1.009	1.000	1.002	1.002	1.003	0.998	1.000	1.004	1.003	0.999	0.999	1.009	1.010	1.008	1.005	1.006	1.003	1.013	1.012	1.007	1.009	1.005	1.005
Beam Hill	0.987	0.931	0.993	0.942	0.972	0.936	0.968	0.942	0.966	0.927	0.960	0.921	0.965	0.924	0.969	0.923	0.970	0.924	0.965	0.923	0.973	0.936	0.968	0.935
Cark Wind Farm	0.982	0.943	0.991	0.959	0.978	0.951	0.974	0.960	0.973	0.940	0.972	0.938	0.979	0.942	0.985	0.942	0.985	0.945	0.976	0.943	0.984	0.953	0.979	0.951
Carnsore	1.055	1.043	1.055	1.044	1.049	1.038	1.045	1.035	1.047	1.033	1.045	1.027	1.043	1.025	1.043	1.027	1.045	1.027	1.048	1.030	1.056	1.040	1.055	1.044
Mountain Lodge	1.003	0.994	1.004	0.994	1.005	0.994	0.993	0.989	0.992	0.981	0.992	0.981	0.990	0.985	0.991	0.979	0.994	0.983	0.997	0.989	1.002	0.988	1.002	0.989
Gartnaneane	0.996	0.993	0.997	0.993	0.994	0.990	0.989	0.988	0.988	0.989	0.987	0.990	0.986	0.990	0.987	0.990	0.992	0.995	0.997	1.004	0.999	1.000	1.002	0.999
Raheen Barr	1.055	1.033	1.055	1.036	1.050	1.033	1.055	1.027	1.052	1.028	1.043	1.021	1.046	1.014	1.049	1.022	1.054	1.025	1.051	1.024	1.051	1.037	1.045	1.038
Richfield	1.055	1.043	1.055	1.044	1.049	1.038	1.045	1.035	1.047	1.033	1.045	1.027	1.043	1.025	1.043	1.027	1.045	1.027	1.048	1.030	1.056	1.040	1.055	1.044
Sorne Hill	0.987	0.931	0.993	0.942	0.972	0.936	0.968	0.942	0.966	0.927	0.960	0.921	0.965	0.924	0.969	0.923	0.970	0.924	0.965	0.923	0.973	0.936	0.968	0.935
Taurbeg	1.043	1.033	1.044	1.037	1.045	1.036	1.050	1.042	1.049	1.036	1.056	1.027	1.055	1.027	1.050	1.026	1.048	1.023	1.037	1.010	1.036	1.016	1.033	1.019
Tournafulla	1.001	1.000	1.001	1.004	1.004	1.010	1.017	1.016	1.017	1.016	1.019	1.006	1.015	1.000	1.010	1.004	1.003	0.998	0.990	0.982	0.974	0.974	0.970	0.978
Antrim	0.979	0.972	0.981	0.971	0.978	0.977	0.971	0.977	0.970	0.972	0.973	0.981	0.968	0.981	0.966	0.979	0.967	0.977	0.979	0.984	0.984	0.983	0.988	0.982
Ballylumford	0.964	0.965	0.968	0.964	0.964	0.969	0.956	0.971	0.957	0.963	0.963	0.976	0.959	0.977	0.955	0.974	0.955	0.971	0.967	0.979	0.971	0.976	0.975	0.974
Ballymena	0.985	0.976	0.987	0.975	0.984	0.980	0.976	0.981	0.975	0.976	0.978	0.984	0.973	0.983	0.971	0.982	0.972	0.981	0.985	0.988	0.990	0.987	0.994	0.986
Banbridge	0.997	0.988	0.998	0.987	0.994	0.990	0.988	0.990	0.987	0.987	0.989	0.992	0.985	0.992	0.984	0.991	0.986	0.989	0.995	0.997	0.999	0.996	1.002	0.995
Ballynahinch	0.998	0.990	1.000	0.991	0.996	0.990	0.987	0.991	0.986	0.986	0.990	0.992	0.985	0.992	0.983	0.990	0.985	0.989	0.998	0.998	1.004	0.997	1.008	0.996
Castlereagh	0.983	0.977	0.986	0.975	0.982	0.980	0.974	0.981	0.974	0.976	0.978	0.984	0.973	0.985	0.971	0.982	0.972	0.981	0.984	0.988	0.989	0.987	0.992	0.985
Belast Central	0.990	0.981	0.992	0.980	0.988	0.985	0.981	0.985	0.980	0.980	0.983	0.988	0.978	0.988	0.976	0.986	0.978	0.985	0.990	0.993	0.995	0.992	0.999	0.990
Coolkeeragh	0.966	0.964	0.968	0.961	0.967	0.965	0.961	0.968	0.954	0.964	0.960	0.975	0.953	0.975	0.952	0.973	0.957	0.974	0.971	0.985	0.969	0.978	0.973	0.976
Glengormley	0.988	0.973	0.990	0.972	0.987	0.977	0.975	0.976	0.974	0.971	0.979	0.980	0.967	0.977	0.964	0.973	0.968	0.973	0.977	0.977	0.983	0.977	0.988	0.977
Kilroot	0.974	0.969	0.976	0.968	0.973	0.973	0.966	0.975	0.966	0.969	0.970	0.979	0.965	0.979	0.963	0.978	0.964	0.976	0.975	0.981	0.979	0.979	0.983	0.978
Lisburn	0.990	0.981	0.992	0.981	0.988	0.985	0.981	0.986	0.980	0.981	0.983	0.988	0.979	0.988	0.977	0.986	0.979	0.985	0.990	0.993	0.995	0.992	0.999	0.991
Lisaghmore	0.967	0.964	0.969	0.961	0.968	0.964	0.963	0.968	0.953	0.964	0.959	0.976	0.951	0.974	0.951	0.973	0.957	0.975	0.971	0.986	0.968	0.979	0.971	0.976
Loguestown	0.996	0.981	0.997	0.979	0.992	0.981	0.983	0.982	0.976	0.980	0.980	0.986	0.972	0.984	0.972	0.983	0.978	0.984	0.994	0.996	0.994	0.991	0.998	0.990
Tandragee	0.985	0.980	0.987	0.979	0.984	0.982	0.978	0.983	0.977	0.979	0.980	0.986	0.977	0.987	0.976	0.985	0.977	0.984	0.987	0.991	0.990	0.989	0.993	0.988
Waringstown	0.996	0.987	0.997	0.986	0.993	0.989	0.987	0.989	0.986	0.986	0.988	0.992	0.984	0.991	0.983	0.990	0.985	0.989	0.994	0.996	0.998	0.995	1.001	0.994
Creagh	0.979	0.973	0.982	0.971	0.979	0.978	0.971	0.979	0.970	0.972	0.972	0.981	0.967	0.981	0.964	0.979	0.965	0.977	0.979	0.984	0.983	0.983	0.988	0.981
Cregagh	0.989	0.981	0.992	0.980	0.988	0.984	0.980	0.985	0.980	0.980	0.982	0.987	0.978	0.988	0.976	0.986	0.978	0.984	0.990	0.993	0.995	0.991	0.999	0.990
Donegal	0.986	0.978	0.989	0.977	0.985	0.982	0.977	0.983	0.977	0.978	0.980	0.986	0.976	0.986	0.974	0.984	0.975	0.983	0.987	0.990	0.993	0.989	0.996	0.988
Drumnakelly	0.994	0.985	0.996	0.984	0.992	0.987	0.986	0.988	0.984	0.985	0.986	0.990	0.982	0.990	0.981	0.988	0.983	0.988	0.992	0.994	0.995	0.993	0.999	0.992
Dungannon	1.006	0.990	1.007	0.990	1.003	0.992	0.995	0.992	0.991	0.992	0.989	0.990	0.984	0.989	0.983	0.988	0.987	0.989	0.989	0.991	0.992	0.990	0.996	0.989
Hannahstown	0.981	0.975	0.984	0.974	0.980	0.979	0.972	0.980	0.972	0.974	0.976	0.983	0.971	0.983	0.969	0.981	0.970	0.979	0.982	0.987	0.986	0.985	0.990	0.984
Kells	0.975	0.970	0.977	0.969	0.974	0.974	0.967	0.975	0.966	0.970	0.970	0.979	0.965	0.980	0.963	0.978	0.965	0.976	0.975	0.983	0.980	0.981	0.984	0.979
Larne	0.973	0.970	0.976	0.968	0.972	0.974	0.964	0.975	0.964	0.969	0.969	0.979	0.964	0.979	0.961	0.977	0.962	0.974	0.974	0.982	0.979	0.980	0.983	0.979

	January		February		March		April		May		June		July		August		September		October		November		December	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Limavady	0.983	0.972	0.985	0.969	0.981	0.972	0.974	0.974	0.965	0.972	0.970	0.980	0.962	0.978	0.962	0.977	0.969	0.978	0.984	0.990	0.983	0.984	0.987	0.983
Lisburn	0.990	0.981	0.992	0.981	0.988	0.985	0.981	0.986	0.980	0.981	0.983	0.988	0.979	0.988	0.977	0.986	0.979	0.985	0.990	0.993	0.995	0.992	0.999	0.991
Magherafelt	0.975	0.971	0.978	0.970	0.975	0.974	0.969	0.976	0.967	0.971	0.970	0.980	0.965	0.980	0.963	0.978	0.965	0.977	0.977	0.985	0.980	0.982	0.984	0.981
Newtownards	0.994	0.984	0.997	0.983	0.993	0.988	0.984	0.988	0.983	0.984	0.986	0.990	0.981	0.990	0.980	0.989	0.982	0.987	0.995	0.996	1.000	0.994	1.004	0.994
Newry	1.007	0.995	1.008	0.994	1.004	0.997	0.997	0.997	0.995	0.994	0.997	0.998	0.993	0.998	0.993	0.996	0.995	0.996	1.005	1.004	1.010	1.003	1.013	1.002
Omagh	1.003	0.983	1.003	0.981	0.999	0.984	0.990	0.984	0.983	0.985	0.984	0.984	0.975	0.981	0.976	0.980	0.982	0.983	0.985	0.986	0.988	0.984	0.992	0.981
Rathgael	0.997	0.986	1.000	0.985	0.996	0.990	0.987	0.990	0.986	0.985	0.989	0.992	0.984	0.992	0.983	0.990	0.985	0.989	0.997	0.998	1.004	0.997	1.008	0.996
Rosebank	0.989	0.980	0.991	0.979	0.987	0.984	0.979	0.984	0.979	0.980	0.982	0.987	0.977	0.987	0.975	0.986	0.977	0.984	0.989	0.992	0.994	0.991	0.998	0.989
Strabane	0.976	0.968	0.978	0.965	0.976	0.968	0.970	0.971	0.960	0.969	0.965	0.976	0.957	0.974	0.957	0.973	0.963	0.976	0.974	0.984	0.972	0.979	0.976	0.976

2008 Rolling Average Indicative TLAFs																								
	January		February		March		April		May		June		July		August		September		October		November		December	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Huntstown 1	0.983	0.988	0.982	0.988	0.981	0.986	0.980	0.984	0.981	0.985	0.978	0.988	0.978	0.988	0.979	0.988	0.977	0.987	0.978	0.989	0.983	0.992	0.982	0.992
Tynagh	0.962	0.966	0.961	0.966	0.966	0.970	0.967	0.972	0.969	0.972	0.968	0.971	0.967	0.970	0.967	0.971	0.964	0.967	0.963	0.966	0.956	0.962	0.956	0.963
Marina	1.032	1.049	1.033	1.050	1.037	1.048	1.035	1.049	1.041	1.052	1.053	1.045	1.051	1.042	1.045	1.043	1.048	1.049	1.043	1.045	1.044	1.053	1.040	1.054
Rhode	1.002	1.000	1.002	0.999	0.999	0.997	0.999	0.997	0.998	0.996	0.998	1.000	0.999	1.002	1.000	1.001	0.998	0.999	1.000	1.001	1.004	1.005	1.003	1.004
Aghada	1.017	1.038	1.018	1.039	1.024	1.039	1.022	1.040	1.028	1.043	1.042	1.037	1.040	1.035	1.033	1.036	1.032	1.040	1.029	1.036	1.030	1.042	1.026	1.043
Meentycat	1.006	0.945	1.007	0.954	0.979	0.948	0.980	0.953	0.984	0.950	0.982	0.939	0.981	0.939	0.984	0.940	0.976	0.938	0.972	0.939	0.978	0.949	0.974	0.943
Ardnacrusha	0.997	1.007	0.998	1.009	1.010	1.020	1.015	1.027	1.022	1.029	1.033	1.023	1.032	1.022	1.027	1.023	1.027	1.026	1.021	1.019	1.011	1.021	1.008	1.019
Ratrussan	0.999	0.982	1.001	0.984	0.994	0.980	0.987	0.982	0.984	0.969	0.985	0.968	0.983	0.979	0.986	0.969	0.987	0.971	0.993	0.974	1.000	0.982	1.001	0.983
Booltiagh	1.001	1.005	1.001	1.007	1.010	1.013	1.015	1.017	1.020	1.019	1.023	1.008	1.023	1.008	1.019	1.009	1.020	1.011	1.015	1.007	1.008	1.010	1.004	1.011
Ballywater	1.039	1.028	1.039	1.028	1.030	1.020	1.029	1.019	1.030	1.019	1.028	1.018	1.028	1.017	1.028	1.019	1.034	1.020	1.036	1.022	1.046	1.033	1.044	1.034
Coomagearlahy 1	1.008	1.020	1.010	1.022	1.008	1.017	1.011	1.021	1.017	1.023	1.024	1.016	1.023	1.014	1.017	1.015	1.018	1.017	1.012	1.010	1.004	1.012	1.005	1.018
Dublin Bay Power	0.983	0.989	0.983	0.988	0.981	0.986	0.980	0.985	0.980	0.986	0.981	0.990	0.981	0.991	0.982	0.992	0.980	0.989	0.982	0.991	0.986	0.995	0.986	0.994
Derrybrien	0.985	0.981	0.985	0.981	0.991	0.985	0.994	0.991	0.994	0.990	1.002	0.986	1.004	0.990	1.000	0.987	1.000	0.988	0.997	0.985	0.991	0.986	0.989	0.987
Edenderry	0.958	0.939	0.954	0.933	0.951	0.933	0.950	0.940	0.950	0.935	0.960	0.946	0.979	0.970	0.959	0.945	0.969	0.954	0.969	0.954	0.957	0.937	0.958	0.938
Cliff	1.000	0.964	1.001	0.973	0.989	0.977	0.991	0.982	0.996	0.980	0.997	0.973	0.996	0.973	0.998	0.973	0.985	0.969	0.980	0.969	0.980	0.975	0.976	0.966
Cathleen's Falls	1.003	0.966	1.003	0.975	0.991	0.978	0.992	0.983	0.997	0.981	0.997	0.973	0.996	0.974	0.998	0.974	0.986	0.970	0.982	0.969	0.983	0.975	0.978	0.967
Great Island	1.027	1.032	1.028	1.033	1.025	1.029	1.024	1.028	1.026	1.029	1.028	1.029	1.028	1.027	1.027	1.029	1.030	1.029	1.031	1.030	1.037	1.038	1.033	1.038
Kingsmountain	1.049	1.009	1.050	1.012	1.036	1.010	1.037	1.010	1.037	1.011	1.024	0.999	1.025	0.996	1.026	1.000	1.017	0.995	1.015	0.995	1.018	1.001	1.016	1.000
Lee (ESB)	1.022	1.043	1.023	1.045	1.032	1.043	1.031	1.046	1.038	1.048	1.049	1.040	1.047	1.037	1.041	1.037	1.043	1.043	1.038	1.039	1.034	1.046	1.028	1.045
Liffey (ESB)	1.012	1.015	1.011	1.015	1.011	1.011	1.011	1.014	1.013	1.010	1.018	1.012	1.018	1.015	1.018	1.012	1.020	1.014	1.021	1.014	1.022	1.022	1.020	1.021
Lough Ree Power (	0.999	0.976	0.999	0.977	0.997	0.975	0.998	0.981	1.000	0.978	0.997	0.973	0.996	0.976	1.001	0.978	1.004	0.979	1.002	0.978	0.998	0.975	0.996	0.976
Moneypoint (ESB)	0.959	0.971	0.959	0.971	0.968	0.978	0.971	0.982	0.974	0.983	0.976	0.985	0.976	0.986	0.975	0.985	0.972	0.981	0.971	0.978	0.963	0.975	0.962	0.974
North Wall (ESB)	0.985	0.990	0.984	0.990	0.983	0.988	0.982	0.986	0.983	0.987	0.980	0.990	0.980	0.990	0.981	0.990	0.978	0.988	0.979	0.990	0.984	0.994	0.984	0.993
Poolbeg (ESB)	0.986	0.991	0.985	0.991	0.983	0.989	0.983	0.988	0.983	0.988	0.983	0.992	0.983	0.993	0.984	0.993	0.983	0.991	0.985	0.993	0.988	0.997	0.988	0.996
Rhode PCP (ESB)	1.002	1.000	1.002	0.999	0.999	0.997	0.999	0.997	0.998	0.996	0.998	1.000	0.999	1.002	1.000	1.001	0.998	0.999	1.000	1.001	1.004	1.005	1.003	1.004
Seal Rock	0.961	0.979	0.960	0.977	0.978	0.991	0.983	0.997	0.989	0.997	0.997	0.990	0.996	0.990	0.991	0.990	0.994	0.992	0.987	0.983	0.976	0.983	0.974	0.985
Tarbert (ESB)	0.960	0.988	0.960	0.989	0.979	0.998	0.987	1.006	0.994	1.009	1.000	1.003	1.000	1.001	0.994	1.003	0.998	1.003	0.990	0.994	0.978	0.993	0.976	0.995
Tawnaghmore PCP	1.080	1.034	1.081	1.037	1.064	1.031	1.065	1.028	1.064	1.031	1.051	1.018	1.053	1.013	1.053	1.019	1.051	1.017	1.050	1.016	1.054	1.028	1.050	1.027
Turlough Hill	0.984	0.996	0.983	0.996	0.982	0.993	0.981	0.992	0.981	0.994	0.982	0.996	0.982	0.998	0.982	0.997	0.980	0.996	0.982	0.998	0.985	1.001	0.985	0.997
West Offaly Power	0.987	0.982	0.987	0.981	0.991	0.984	0.992	0.988	0.994	0.986	0.997	0.986	1.002	0.994	0.998	0.989	0.997	0.987	0.996	0.986	0.993	0.985	0.992	0.988

2007 Rolling Average Indicative TLAFs

	January		February		March		April		May		June		July		August		September		October		November		December	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Huntstown 1	0.980	0.980	0.980	0.980	0.980	0.979	0.980	0.979	0.980	0.979	0.978	0.984	0.978	0.984	0.978	0.984	0.975	0.980	0.975	0.980	0.979	0.982	0.979	0.981
Tynagh	0.964	0.968	0.964	0.968	0.966	0.971	0.966	0.971	0.966	0.971	0.962	0.968	0.962	0.968	0.962	0.968	0.961	0.966	0.961	0.966	0.966	0.974	0.966	0.973
Marina	1.016	1.045	1.016	1.045	1.020	1.041	1.020	1.041	1.020	1.041	1.030	1.031	1.030	1.031	1.030	1.031	1.028	1.041	1.028	1.041	1.026	1.049	1.025	1.050
Rhode	0.996	0.992	0.996	0.992	0.994	0.991	0.994	0.991	0.994	0.991	0.994	0.997	0.994	0.997	0.994	0.997	0.991	0.992	0.991	0.992	0.996	0.995	0.996	0.994
Aghada	1.002	1.032	1.002	1.032	1.007	1.031	1.007	1.031	1.007	1.031	1.016	1.022	1.016	1.022	1.016	1.022	1.014	1.031	1.014	1.031	1.013	1.037	1.012	1.038
Meentycat	1.030	0.974	1.030	0.974	1.004	0.978	1.004	0.978	1.004	0.978	1.001	0.961	1.001	0.961	1.001	0.961	0.992	0.965	0.992	0.965	0.996	0.974	0.995	0.973
Ardnacrusha	1.005	1.023	1.005	1.023	1.007	1.021	1.007	1.021	1.007	1.021	1.014	1.017	1.014	1.017	1.014	1.017	1.011	1.021	1.011	1.021	1.012	1.027	1.011	1.027
Ballywater	1.026	1.015	1.026	1.015	1.019	1.008	1.019	1.008	1.019	1.008	1.015	1.008	1.015	1.008	1.015	1.008	1.020	1.008	1.020	1.008	1.029	1.018	1.029	1.018
Dublin Bay Power	0.980	0.980	0.980	0.980	0.979	0.979	0.979	0.979	0.979	0.979	0.978	0.985	0.978	0.985	0.978	0.985	0.976	0.980	0.976	0.980	0.980	0.983	0.980	0.982
Derrybrien	0.983	0.981	0.983	0.981	0.988	0.982	0.988	0.982	0.983	0.982	0.989	0.978	0.989	0.978	0.989	0.978	0.993	0.983	0.993	0.983	0.989	0.986	0.989	0.987
Edenderry	0.950	0.932	0.950	0.932	0.943	0.929	0.943	0.929	0.943	0.929	0.956	0.945	0.956	0.945	0.956	0.945	0.956	0.942	0.956	0.942	0.949	0.931	0.951	0.932
Cliff	1.017	0.986	1.017	0.986	1.007	1.000	1.007	1.000	1.007	1.000	1.011	0.988	1.011	0.988	1.011	0.988	0.997	0.990	0.997	0.990	0.993	0.995	0.991	0.992
Cathleen's Falls	1.020	0.988	1.020	0.988	1.009	1.000	1.009	1.000	1.009	1.000	1.011	0.988	1.011	0.988	1.011	0.988	0.999	0.990	0.999	0.990	0.995	0.995	0.994	0.992
Great Island	1.013	1.023	1.013	1.023	1.011	1.019	1.011	1.019	1.011	1.019	1.012	1.018	1.012	1.018	1.012	1.018	1.015	1.019	1.015	1.019	1.020	1.026	1.019	1.025
Kingsmountain	1.063	1.019	1.063	1.019	1.047	1.019	1.047	1.019	1.047	1.019	1.035	1.008	1.035	1.008	1.035	1.008	1.030	1.012	1.030	1.012	1.035	1.019	1.034	1.019
Lee (ESB)	1.009	1.041	1.009	1.041	1.018	1.037	1.018	1.037	1.018	1.037	1.027	1.027	1.027	1.027	1.027	1.027	1.025	1.038	1.025	1.038	0.684	0.695	0.683	0.695
Liffey (ESB)	1.003	1.007	1.003	1.007	1.005	1.003	1.005	1.003	1.005	1.003	1.010	1.005	1.010	1.005	1.010	1.005	1.009	1.003	1.009	1.003	1.010	1.011	1.010	1.010
Lough Ree Power (ES	1.004	0.978	1.004	0.978	0.997	0.975	0.997	0.975	0.997	0.975	0.993	0.971	0.993	0.971	0.993	0.971	1.003	0.981	1.003	0.981	1.003	0.980	1.002	0.980
Moneypoint (ESB)	0.959	0.975	0.959	0.975	0.967	0.980	0.967	0.980	0.967	0.980	0.968	0.982	0.968	0.982	0.968	0.982	0.968	0.981	0.968	0.981	0.963	0.980	0.963	0.979
North Wall (ESB)	0.982	0.981	0.982	0.981	0.981	0.981	0.981	0.981	0.981	0.981	0.980	0.986	0.980	0.986	0.980	0.986	0.976	0.981	0.976	0.981	0.980	0.983	0.980	0.982
Poolbeg (ESB)	0.983	0.982	0.983	0.982	0.982	0.982	0.982	0.982	0.982	0.982	0.981	0.987	0.981	0.987	0.981	0.987	0.979	0.983	0.979	0.983	0.983	0.985	0.983	0.984
Rhode PCP (ESB)	0.996	0.992	0.996	0.992	0.994	0.991	0.994	0.991	0.994	0.991	0.994	0.997	0.994	0.997	0.994	0.997	0.991	0.992	0.991	0.992	0.996	0.995	0.996	0.994
Seal Rock	0.955	0.977	0.955	0.977	0.971	0.986	0.971	0.986	0.971	0.986	0.976	0.978	0.976	0.978	0.976	0.978	0.981	0.984	0.981	0.984	0.981	1.003	0.981	1.003
Tarbert (ESB)	0.958	0.994	0.958	0.994	0.972	0.998	0.972	0.998	0.972	0.998	0.979	0.995	0.979	0.995	0.979	0.995	0.984	1.003	0.984	1.003	0.977	1.004	0.977	1.005
Tawnaghmore PCP	1.089	1.038	1.089	1.038	1.070	1.034	1.070	1.034	1.070	1.034	1.059	1.024	1.059	1.024	1.059	1.024	1.063	1.033	1.063	1.033	1.069	1.045	1.068	1.046
Turlough Hill	0.980	0.991	0.980	0.991	0.979	0.989	0.979	0.989	0.979	0.989	0.978	0.994	0.978	0.994	0.978	0.994	0.976	0.990	0.976	0.990	0.979	0.992	0.979	0.989
West Offaly Power	0.990	0.986	0.990	0.986	0.986	0.980	0.986	0.980	0.986	0.980	0.988	0.980	0.988	0.983	0.988	0.980	0.990	0.984	0.990	0.984	0.990	0.986	0.991	0.988

Appendix G
Zonal Losses Indicatives

AREA 4																								
2011	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	0.986	0.976	0.988	0.980	0.987	0.981	0.987	0.981	0.985	0.981	0.984	0.974	0.986	0.976	0.988	0.977	0.993	0.980	0.985	0.978	0.987	0.982	0.986	0.981
2009	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	0.999	1.001	0.998	1.005	0.994	1.002	1.006	1.003	0.996	0.996	0.999	0.993	1.002	0.994	1.002	0.993	0.994	0.985	0.983	0.975	0.982	0.977	0.982	0.979
2008	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	0.978	0.982	0.977	0.983	0.987	0.990	0.997	1.002	1.007	1.005	1.014	1.003	1.015	1.005	1.008	1.004	1.002	0.998	0.995	0.989	0.983	0.984	0.979	0.985

AREA 5																								
2011	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	1.040	1.032	1.042	1.035	1.041	1.035	1.047	1.036	1.052	1.037	1.049	1.031	1.053	1.033	1.050	1.033	1.050	1.035	1.036	1.032	1.040	1.033	1.040	1.033

AREA 6																								
2011	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	1.028	1.027	1.029	1.029	1.029	1.029	1.031	1.026	1.036	1.020	1.034	1.022	1.036	1.022	1.033	1.023	1.030	1.021	1.025	1.020	1.025	1.016	1.025	1.020

AREA 8																								
2011	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	1.016	1.013	1.017	1.014	1.016	1.015	1.015	1.010	1.018	1.002	1.017	1.005	1.018	1.004	1.016	1.005	1.015	1.003	1.013	1.002	1.014	1.000	1.014	1.004

Appendix H
Banded TLAFs Indicatives

Indicative 2009 Banded TLAFs

		Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Ardnacrusha	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1	1	1	0.98	1	0.98	1	1
Ardnacrusha	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1	1	1	0.98	1	0.98	1	1
Ardnacrusha	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1	1	1	0.98	1	0.98	1	1
Ardnacrusha	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1	1	1	0.98	1	0.98	1	1
Aghada*	220	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.04	1.02	1.02	1	1.02	1	1	1	1	0.96	0.98	0.98	1	0.98
Aghada*	220	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1
Aghada*	220	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1
Aghada*	220	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1
Ratrussan	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Booltiagh	110	1.02	1.02	1.02	1.02	1.02	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1	1	1	1	0.98	1	1	1	1
Crane	110	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1
Coomagearlahy	110	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1	1	1.02	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Coomagearlahy	110	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1	1	1.02	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Coomagearlahy	110	0.96	0.96	0.96	0.96	1.02	1.02	1.02	1.02	1	1	1.02	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Clahane	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.96
Garrow	110	1.02	1	1.02	1	1	1	1.02	1	1	1	1.02	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.96
Irishtown	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Derrybrien	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	1	0.98	1	0.98
Cushaling	110	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.96	1	0.98	0.98	0.96	1	0.98	1.02	1	0.98	0.98	1	0.98	1	1	1	0.98
Cliff	110	0.98	0.98	1	0.98	1	0.98	1	1	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98
Cliff	110	0.98	0.98	1	0.98	1	0.98	1	1	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98
Cathleen's Fall	110	0.98	0.98	1	0.98	1	0.98	1	1	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1
Cathleen's Fall	110	0.98	0.98	1	0.98	1	0.98	1	1	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1
Great Island	110	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02
Great Island	110	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02
Great Island	220	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1.02	1.02
Glanlee	110	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1	1	1.02	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Golagh	110	0.98	0.98	1	0.98	1	0.98	1	0.98	0.98	0.96	0.98	0.96	1	0.98	1	0.96	1	0.98	1	0.96	1	0.98	1	0.98
Huntstown B	220	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Huntstown A	220	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cunghill	110	1	1	1.02	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Inniscarra	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	0.98	1	1	1	1
Inniscarra	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	0.98	1	1	1	1
Carrigadrohid	110	1.04	1.02	1.04	1.04	1.02	1.02	1.04	1.02	1.02	1.02	1.04	1	1.02	1	1.02	1	1	1	1	0.96	1	0.98	1	0.98
Poolaphuca	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Poolaphuca	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Poolaphuca	110	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Lanesboro	110	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	1	1	0.98	1	1	1	1	1	1	1	1
Meentycat	110	0.98	0.96	1	0.96	1	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Ratrussan	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Moneypoint	380	0.98	1	0.98	1	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98
Moneypoint	380	0.98	1	0.98	1	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98
Moneypoint	380	0.98	1	0.98	1	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98
Marina	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1

		Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Finglas / North Wall	110	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
North Wall	220	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poolbeg B	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poolbeg B	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poolbeg B	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Shellybanks	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Derryiron	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Derryiron	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aughinish	110	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	0.98	0.98	0.96	0.96	0.96	0.96	0.96	0.96
Aughinish	110	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	0.98	0.98	0.96	0.96	0.96	0.96	0.96	0.96
Tarbert	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96
Tarbert	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96
Tarbert	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Tarbert	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Turlough Hill	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Turlough Hill	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Turlough Hill	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Turlough Hill	220	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Tynagh	220	0.98	1	0.98	1	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1
Shannonbridge	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	1
Arklow	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Kilteel	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Kilteel	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Kilteel	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Ballylickey	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1	1.04	1	1.02	1	1	0.98	1	1	1.02	1
Trien	110	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96
Trillick	110	0.98	0.96	1	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Charleville	110	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	0.98	1	1	1	1
Letterkenny	110	1	0.96	1	0.98	1	0.98	1	0.98	0.98	0.96	0.98	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.98
Dunmanway	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	0.98	1	1	1.02	1
Wexford	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02
Trillick	110	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Meath Hill	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Trien	110	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96
-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Binbane	110	0.98	0.98	1	0.98	1	0.98	1	0.98	0.98	0.96	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98
Tullabrack	110	1.02	1.02	1.02	1.02	1.02	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1	1	1	1	0.98	1	1	1	1
Tralee	110	1	1	1	1	1	1	1.02	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Castlebar	110	1.04	1.02	1.04	1.02	1.02	1.02	1.04	1.02	1.02	1	1.02	1	1.02	1	1.02	1	1.04	1	1.02	1	1.04	1	1.04	1.02
Wexford	110	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02
Letterkenny	110	1	0.96	1	0.98	1	0.98	1	0.98	0.98	0.96	0.98	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.98
Trillick	110	0.98	0.96	1	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Trien	110	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96
Tawnaghmore	110	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	1	1.02	1	1.04	1	1.04	1	1.04	1	1.04	1.02	1.04	1.02
Tawnaghmore	110	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	1	1.02	1	1.04	1	1.04	1	1.04	1	1.04	1.02	1.04	1.02
Glenlara	110	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.02	1.04	1	1.04	1	1.04	1	1.02	1	1	0.98	1	1	1	1

		Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Tralee	110	1	1	1	1	1	1	1.02	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Tralee	110	1	1	1	1	1	1	1.02	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98
Antrim	110	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Ballylumford	110	0.96	0.98	0.96	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1
Ballylumford	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1
Ballymena	110	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Banbridge	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Ballyvallagh	110	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	0.98	1
Ballynahinch	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1	1	1	1
Carnmoney	110	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Castlereagh	110	1	0.98	1	0.98	1	0.98	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Castlereagh	275	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Belast Central	110	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Coleraine	110	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Coolkeeragh	110	0.96	0.96	0.96	0.96	0.98	0.96	0.96	0.96	0.96	0.98	0.98	1	0.96	1	0.96	1	0.98	1	0.98	1	0.98	1	0.98	1
Coolkeeragh	275	0.96	0.96	0.96	0.96	0.98	0.96	0.96	0.98	0.96	0.98	0.98	1	0.96	1	0.96	1	0.98	1	0.98	1	0.98	1	0.98	1
Creagh	110	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Cregagh	110	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Donegal	110	1	0.98	1	0.98	1	0.98	0.98	1	1	1	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1
Drumnakelly	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dungannon	110	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Eden	110	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Enniskillen	110	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	0.98	0.98	0.98	0.98	1	1	0.98	1	1	1	1	1
Aghyoule	110	1	0.98	1	0.98	1	0.98	1	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Finaghy	110	0.98	0.98	1	0.98	1	0.98	0.98	1	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Glengormley	110	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	0.98
Hannahstown	110	0.98	0.98	1	0.98	1	0.98	0.98	1	0.98	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Hannahstown	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Kells	110	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Kells	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Kilroot	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Knock	110	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Larne	110	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	0.98	1
Limavady	110	0.98	0.98	0.98	0.96	0.98	0.96	0.96	0.98	0.96	0.98	0.98	1	0.98	1	0.96	1	0.98	1	0.98	1	1	1	0.98	1
Lisburn	110	1	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lisaghmore	110	0.96	0.96	0.96	0.96	0.98	0.96	0.96	0.96	0.96	0.98	0.98	1	0.96	1	0.96	1	0.98	1	0.98	1	0.98	1	0.98	1
Loguestown	110	0.98	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Magherafelt	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
yle (Ballycronan Mor	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1
Newtownards	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Newry	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1	1	1	1
Omagh	110	0.98	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1
Rathgael	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1	1	1	1
Rosebank	110	1	0.98	1	0.98	1	0.98	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Slieve Kirk	110																			0.98	1	0.98	1	0.98	1
Slieve Kirk T-Off	110																			0.98	1	0.98	1	0.98	1

		Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Springtown	110																			0.98	1	0.98	1	0.98	1
Strabane	110	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.98	0.96	0.98	0.98	1	0.96	1	0.96	1	0.98	1	0.98	1	0.98	1	0.98	1
Tandragee	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Tandragee	275	1	1	1	0.98	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Tamnamore	110	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Tamnamore	275	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	0.98	1
Waringstown	110	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
West Belfast Central	110	1	0.98	1	0.98	1	0.98	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Indicative 2008 Banded TLAFs																								
	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Aghada (ESB)	1.02	1.04	1.02	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04
Aghada PCP (ESB)	1.02	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04
Ardnacrusha (ESB)	1	1	1	1	1.02	1.02	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1	1	1	1	1
Ballywater (Ballywater Windfarms Ltd.)	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04
Barnesmore Wind Farm (Golagh)	0.98	0.96	0.98	0.98	0.98	0.96	0.98	0.98	1	0.96	1	0.96	0.98	0.96	1	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Booltiagh (Booltiagh Windfarm Ltd.)	1	1	1	1	1	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	1	1	1
Clahane (Pallas Windfarm Ltd.)**															1.02	1.04	1.02	1.02	1	1	1	1	1	1
Coomacheo (Coomacheo Windfarm Ltd.)**											1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1	1	1	1	1	1.02
Coomagearlahy (SWS Kilgarvan Windfarm Ltd.)	1	1	1	1	1	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1	1	1	1	1	1.02
Derrybrien (Gort Windfarms Ltd.)	1	1	1	1	1	1	1	1	1	1	1.02	1	1.02	1	1.02	1	1	1	1	1	1	1	1	1
Dublin Bay Power (Synergen)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Edenderry (Edenderry Power Ltd.)	0.98	0.96	0.96	0.96	0.98	0.96	0.98	0.98	0.98	0.96	0.98	0.96	1.02	1.02	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Erne (ESB)	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.96
Erne (ESB)	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.96
Glanlee Wind Farm	1	1	1	1	1	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1	1	1	1	1	1.02
Great Island (ESB)	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04
Great Island (ESB)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Huntstown (Huntstown Power Ltd.)	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Huntstown 2 (Viridian Power Ltd.)	1	1	0.98	1	1	1	0.98	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Kingsmountain (Brickmount Ltd.)	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1	1.02	1	1	1	1	1	1	1	1	1
Lee (ESB)	1.02	1.02	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.02	1.02	1.02	1.02
Lee (ESB)	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04
Liffey (ESB)	1	1.02	1	1.02	1	1	1	1.02	1.02	1	1.02	1	1.02	1.02	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Lough Ree Power (ESB)	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1.02	1	1	1	1	0.98	1	0.98	1	1
Marina (ESB)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Meentycat (Meentycat Ltd.)	0.98	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.98	0.96	0.96	0.96
Moneypoint (ESB)*****	0.98	0.98	0.96	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98
Mountain Lodge (Mountain Lodge Power Ltd.)**							1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98
Ratrussan Windfarm (Bindoo Windfarm Ltd.)	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98
North Wall (ESB)	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
North Wall (ESB)*****	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1
Poolbeg (ESB)***	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poolbeg (ESB)****	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1
Rhode PCP (ESB)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Seal Rock (Aughinish Alumina)	0.98	1	0.98	0.98	1	1	1	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1	1	1	1	0.98	1
Tarbert (ESB)	0.98	1	0.98	1	1	1	1	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1	1	1	0.98	1	0.98	1
Tarbert (ESB)	0.98	1	0.98	1	1	1	1	1.02	1.02	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1	1	1	1	0.98	1
Tawnaghmore PCP (ESB)	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02
Turlough Hill (ESB)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Tynagh CCGT (Tynagh Energy Ltd.)	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.96	0.96	0.98
West Offaly Power (ESB)	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1	1	1	1	1	1	1	1	1	1	1
Arklow Banks (Arklow Energy Ltd.)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Arthurstown Landfill Phase 2 (Irish Power Systen	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Arthurstown Landfill Phase 3 (Irish Power Systen	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Arthurstown Landfill Phase 1 & 4 (Irish Power Sys	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Glanta Commmons (Ballybane Windfarm)**															1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Beam Hill (Beam Wind Ltd.)	0.98	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.98	0.96	0.96	0.96
Cark Wind Farm (RES-Gen Ltd.)	1	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Carnsore (Hibernian)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04
Knockawarriga (SWS Knockawarriga Windfarm Ltd.) **									1.04	1.04	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1	1	1	1	0.98	1
Meenachullalan (Airoishin Wind Energy Ltd.)**							0.98	0.98	1	0.98	1	0.98	1	0.96	1	0.98	1	0.96	0.98	0.96	0.98	0.98	0.98	0.96
Muingnaminnane (Muingnaminnane Windfarms Ltd.)**											1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.02	1.02	1	1	1	1	1.02
Liffey (ESB)*	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Culliagh (Dedondo Ltd.)	1	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96
Gartnaneane (Gartnaneane Ltd.)	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	1	1	1	1	1	1	1	1	1
Moanmore (Kilrush Energy Ltd.)	1	1	1	1	1.02	1.02	1.02	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1	1	1	1	1
Raheen Barr (Matrix Energy Partnership)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.04	1.02	1.02
Richfield (Richfield Windfarm (ROI) Ltd.)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04
Sorne Hill (Sorne Wind Ltd.)	0.98	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.98	0.96	0.96	0.96
Taurbeg (Taurbeg Ltd.)	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.02	1.02
Tournafulla Phase 2 (Airtricity)**					1	1	1.02	1.02	1.04	1.04	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1	1	1	1	0.98	1
Tursillagh 1 (Saorgus Energy Ltd.)	1	1	1	1	1	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.02	1.02	1	1	1	1	1.02
Tursillagh 2 (Saorgus Energy Ltd.)	1	1	1	1	1	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.04	1.04	1.02	1.02	1	1	1	1	1.02
Antrim	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Antrim	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Ballylumford	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98
Ballylumford	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98
Ballymena	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Ballymena	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Banbridge	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Banbridge	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1
Ballyvallagh	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98
Ballynahinch	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Ballynahinch	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Cables at Coolkerragh	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98
Cables at Coolkerragh	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98
Carnmoney	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Carnmoney	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Castlereagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Castlereagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Castlereagh	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Belast Central	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Belast Central	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Coleraine	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	1	0.98	1	1	1	1	1
Coolkerragh	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Coolkerragh	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98
Creagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Creagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Creagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Cregagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Cregagh	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Donegal	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Donegal	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Donegal	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Donegal	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Drumnakelly	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1
Dungannon	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Eden	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Eden	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Enniskillen	1.02	1	1.02	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Derrylin	1.02	1	1.02	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Finaghy	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Finaghy	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Glengormley	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Glengormley	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
Hannahstown	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Hannahstown	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	0.98
Kells	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Kells	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Kilroot	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Knock	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Knock	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Larne	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
Larne	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
Limavady	1	1	1	1	1	1	1	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	1	1	1
Lisburn	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Lisburn	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Lisaghmore	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98
Lisaghmore	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98
Loguestown	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	1	0.98	1	1	1	1	1
Loguestown	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	1	0.98	1	1	1	1	1
Magherafelt	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
Moyle	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.96	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98
Newtownards	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1
Newtownards	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Newry	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Newry	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Norfil	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Norfil	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98
Omagh	1	1	1	1	1	1	1	1	0.98	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Rathgael	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Rathgael	1	1	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Rosebank	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Rosebank	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Strabane	0.98	1	1	1	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98
Tandragee	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	1	1	1	1
Tandragee	1	1	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	1	1	1	1
Tandragee	1	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1	1
Coal Island											0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
Coal Island											0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98
Warringstown	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
Warringstown	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	1
West Belfast Central	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1
West Belfast Central	1	1	1	1	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	1	1	1

Indicative 2007 Banded TLAFs																								
	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Aghada (ESB)	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04
Aghada PCP (ESB)	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04
Ardnacrusha (ESB)	1	1	1	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1.02	1.02	1.02	1	1.02	1	1
Ballywater (Ballywater Windfarms Ltd.)	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1.02	1.04	1.02	1	1.02	1	1.02	1	1.02	1	1.04	1.04	1.04	1.04
Booltiagh (Booltiagh Windfarm Ltd.)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1	1.02	1	1	1	1	1
Bindoo Windfarm Ltd.	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	1	1	1
Coomagearlahy (SWS Kilgarvan Windfarm Ltd.)	1	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1.02	1	1.02	1	1	1	1	1	1	1	1	1
Barnesmore Wind Farm (Golagh)	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	1	0.98	1	0.98
Coomagearlahy (SWS Kilgarvan Windfarm Ltd.)	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	1	1	1	1
Derrybrien (Gort Windfarms Ltd.)	1	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1
Dublin Bay Power (Synergen)	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1
denderry (Edenderry Power Ltd.	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.98	0.98	0.98	0.98	0.96	0.96	0.96	0.96
Erne (ESB)	1	0.96	1	0.96	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98
Erne (ESB)	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	0.98	0.98
Glanlee Wind Farm											1.02	1	1.02	1	1.02	1	1	1	1	1	1	1	1	1
Great Island (ESB)	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.04	1.04	1.04	1.04
Great Island (ESB)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
untstown 1 (Huntstown Power Ltd	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1
untstown 2 (Huntstown Power Ltd.)											0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1
Kingsmountain (Brickmount Ltd.)	1.04	1	1.04	1	1.04	1	1.04	1	1.04	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lee (ESB)	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.02	1.02	1.02	1.02	1.04	1.04	1.02	1.04
Lee (ESB)	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Liffey (ESB)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1.02	1.02	1.02	1.02
Lough Ree Power (ESB)	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1	0.98	1	0.98
Marina (ESB)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Meentycat (Meentycat Ltd.)	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96
Moneypoint (ESB)	0.96	0.98	0.96	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
North Wall (ESB)	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1
North Wall (ESB)	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1
Poolbeg (ESB)	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1
Poolbeg (ESB)	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1
Rhode PCP (ESB)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Seal Rock (Aughinish Alumina)	0.98	0.98	0.98	0.98	1	1	1	1	1	1	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1
Tarbert (ESB)	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Tarbert (ESB)	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Tawnaghmore PCP (ESB)	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1	1.04	1	1.04	1	1.04	1	1.04	1	1.04	1.02	1.04	1.02
Turlough Hill (ESB)	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	1	1	1	1
Tynagh CCGT (Tynagh Energy Ltd.)	0.96	0.96	0.96	0.96	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.98
West Offaly Power (ESB)	1	1	1	1	1	0.98	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1
A&L Goodbody (Bord Gais)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.96	0.96	0.96	0.96
Goodbody (Marren Engineering	1	1	1	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.98	1	0.96	0.96	0.96	0.96
owlan (Moneeenatieve Windfarm	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.96	0.96	0.96	0.96
rklow Banks (Arklow Energy Ltd	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Landfill Phase 2 (Irish Power Sy	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Landfill Phase 3 (Irish Power Sy	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Ballineen (CM Power Ltd)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.04	0.96	0.96	0.96	0.96
llinlough I (Jaroma Windfarm Lt	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	0.96	0.96	0.96	0.96
eny I (North Tipperary Windpow	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	0.96	0.96	0.96	0.96
Ballyragget Power (Glanbia Plc.)	1.04	1.04	1.04	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	0.96	0.96	0.96	0.96
Beal Hill (Port Finch Ltd)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.96	0.96	0.96	0.96
Beam Hill (Beam Wind Ltd.)	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96
rnsore (Hibernian Wind Power Lt	1.04	1.04	1.04	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.04	1.04	1.04	1.04
Culliagh (Dedondo Ltd.)	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	1	0.98	1	0.96
Gartnaneane (Gartnaneane Ltd.)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Moanmore (Kilrush Energy Ltd.)	1	1	1	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1	1	1.02	1	1.02
een Barr (Matrix Energy Partners	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1	1.04	1	1.04	1	1.04	1.02	1.04	1.02	1.04	1.04	1.04	1.04
field (Richfield Windfarm (ROI) I	1.04	1.04	1.04	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.04	1.04	1.04	1.04
Sorne Hill (Sorne Wind Ltd.)	1	0.96	1	0.96	1	0.96	1	0.96	1	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98	0.96	1	0.96	0.98	0.96
Taurbeg (Taurbeg Ltd.)	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02	1.04	1.02
Tursillagh 2	1	1.02	1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ANTR1A	0.98	0.98	1	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
ANTR1B	0.98	0.98	1	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
BAFD1-	0.98	0.98	0.98	0.96	0.98	1	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98
BAFD2-	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
BAME1A	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	1
BAME1B	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	1
BANB1A	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
BANB1B	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
BAVA1-	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
BNCH1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	1	1	1	1	1
BNCH1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	1	1	1	1	1
CACO2A	0.98	0.96	0.98	0.96	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.96	1	0.98	0.98	0.98	0.98	0.98
CACO2B	0.98	0.96	0.98	0.96	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.96	1	0.98	0.98	0.98	0.98	0.98
CARN1A	0.98	0.98	1	0.98	1	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	1

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
CARN1B	0.98	0.98	1	0.98	1	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	1	1	0.98	1	1
CAST1A	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
CAST1B	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
CAST2-	1	0.98	1	0.98	1	1	0.98	1	0.98	0.98	1	1	1	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
CENT1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
CENT1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
COLE1-	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	1	0.98	1	1
COOL1-	0.98	0.96	0.98	0.96	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.96	1	0.98	0.98	0.96	0.98	0.98
COOLKEE	0.98	0.96	0.98	0.96	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	0.98	0.96	0.96	1	0.98	0.98	0.98	0.98	0.98
CREAGH	0.98	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	1	0.98	0.98	0.98	1	0.98
CREC1A	0.98	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	1	0.98	0.98	0.98	1	0.98
CREC1B	0.98	0.96	0.98	0.96	0.98	0.98	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	1	0.98	0.98	0.98	1	0.98
CREG1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
CREG1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
DONE1C	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
DONE1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
DONE1D	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
DONE1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
DRUM1-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DUNG1-	1.02	1	1.02	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
EDEN1A	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
EDEN1B	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
ENNISKI	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1.02	1.02	1	1.02	1	1	1	1.02	1	1.02	1	1.02	1	1.02	1
ENNISKI	1.02	1	1.02	1	1.02	1	1.02	1	1.02	1.02	1.02	1	1	1	1	1	1.02	1	1.02	1	1.02	1	1.02	1
FINY1A	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
FINY1B	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
GLEN1A	1	0.98	1	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
HANA1A	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	1
HANA2A	1	0.98	1	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
KELS1-	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
KELS2-	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
KILR2-	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
KNCK1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
KNCK1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
LARN1A	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
LARN1B	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.96	0.98	1	0.98	1	0.98	1	0.98
LIMA1-	1	0.98	1	0.98	1	0.98	0.98	1	0.98	0.98	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	0.98
LISB1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
LISB1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
LSMR1A	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	1	0.98	0.98	0.98	0.98	0.98

	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
LSMR1B	0.98	0.98	0.98	0.96	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.96	1	0.98	0.98	0.98	0.98	0.98
LOGE1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1.02	1	1	0.98	1	1
LOGE1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1.02	1	1	0.98	1	1
MAGF2-	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
BALLYCR	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
BALLYCR	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	0.98	1	0.98	1	0.96	1	0.96	0.98	0.98	0.98	0.98	0.98	1	0.98
NARD1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	1	1	1	1	1	1
NARD1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	1	1	1	1	1	1
NEWY1A	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
NEWY1B	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
NORF1A	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
NORF1B	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	0.98	1	1	0.98	1	0.98	1	0.98	0.98	1	0.98	1	0.98	1	0.98
OMAH1-	1.02	1	1.02	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
RATH1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	1	1	1	1	1
RATH1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	1	1	1	1	1	1	1
ROSE1A	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
ROSE1B	1	0.98	1	0.98	1	1	0.98	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
STRABAN	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98
STRABAN	1	0.98	1	0.98	1	0.98	0.98	0.98	0.98	0.98	1	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1	0.98	1	0.98	1	0.98
TAND1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	1	1	1	1	1	1
TAND1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	1	1	0.98	0.98	1	1	1	1	1	1
TANDRAG	1	0.98	1	0.98	1	1	0.98	1	0.98	0.98	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
COALISL																			1	1	1	0.98	1	1
COALISL																			1	0.98	1	0.98	1	0.98
WARN1A	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WARN1B	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WEST1A	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1
WEST1B	1	0.98	1	0.98	1	1	1	1	1	1	1	1	1	1	0.98	1	0.98	0.98	1	1	1	0.98	1	1

Appendix I[36]
Compression Factors Indicatives

[36] Note that all indicative TLAFs are based on an algorithm normalised around 1. Subject to further consultation an alternative figure could be used.

2009 Compression Factor TLAF																									
		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
Unit	kV	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Ardnacrusha (ESB)	110	1.014	1.012	1.015	1.017	1.013	1.016	1.020	1.016	1.011	1.010	1.017	1.007	1.016	1.006	1.017	1.007	1.009	0.997	0.999	0.986	0.996	0.987	0.997	0.991
Ardnacrusha (ESB)	110	1.014	1.012	1.015	1.017	1.013	1.016	1.020	1.016	1.011	1.010	1.017	1.007	1.016	1.006	1.017	1.007	1.009	0.997	0.999	0.986	0.996	0.987	0.997	0.991
Ardnacrusha (ESB)	110	1.014	1.012	1.015	1.017	1.013	1.016	1.020	1.016	1.011	1.010	1.017	1.007	1.016	1.006	1.017	1.007	1.009	0.997	0.999	0.986	0.996	0.987	0.997	0.991
Ardnacrusha (ESB)	110	1.014	1.012	1.015	1.017	1.013	1.016	1.020	1.016	1.011	1.010	1.017	1.007	1.016	1.006	1.017	1.007	1.009	0.997	0.999	0.986	0.996	0.987	0.997	0.991
Aghada (ESB)	220	1.024	1.021	1.024	1.024	1.022	1.023	1.026	1.022	1.019	1.017	1.025	1.014	1.013	1.007	1.012	1.006	1.000	0.995	0.992	0.979	0.988	0.980	0.991	0.986
Aghada (ESB)	220	1.024	1.021	1.024	1.024	1.022	1.023	1.026	1.022	1.019	1.017	1.025	1.014	1.028	1.017	1.026	1.016	1.018	1.008	1.012	0.997	1.011	0.999	1.014	1.005
Aghada (ESB)	220	1.024	1.021	1.024	1.024	1.022	1.023	1.026	1.022	1.019	1.017	1.025	1.014	1.028	1.017	1.026	1.016	1.018	1.008	1.012	0.997	1.011	0.999	1.014	1.005
Aghada (ESB)	220	1.024	1.021	1.024	1.024	1.022	1.023	1.026	1.022	1.019	1.017	1.025	1.014	1.028	1.017	1.026	1.016	1.018	1.008	1.012	0.997	1.011	0.999	1.014	1.005
Ratrussan (Bindoo Wind Farm Ltd.)	110	1.002	0.997	1.002	0.997	1.003	0.997	1.000	0.998	1.000	0.996	1.000	0.997	0.998	0.996	0.998	0.995	1.000	0.997	1.001	1.002	1.003	1.001	1.002	1.000
Booltiagh (Booltiagh Windfarm Ltd.)	110	1.016	1.012	1.017	1.015	1.014	1.014	1.020	1.014	1.012	1.007	1.015	1.005	1.015	1.004	1.015	1.004	1.009	0.997	1.001	0.989	1.001	0.991	1.002	0.994
Ballywater (Ballywater Windfarms Ltd.)	110	1.024	1.017	1.023	1.018	1.023	1.018	1.022	1.014	1.022	1.014	1.019	1.009	1.012	1.007	1.011	1.006	1.012	1.006	1.013	1.008	1.013	1.009	1.015	1.010
Coomagearlahy 1 (SWS Kilgarvan Windf	110	1.013	1.009	1.013	1.012	1.011	1.011	1.017	1.011	1.007	1.004	1.013	1.001	1.007	0.996	1.006	0.997	0.996	0.987	0.988	0.974	0.987	0.977	0.989	0.982
Coomagearlahy 2 (SWS Kilgarvan Windf	110	1.013	1.009	1.013	1.012	1.011	1.011	1.017	1.011	1.007	1.004	1.013	1.001	1.007	0.996	1.006	0.997	0.996	0.987	0.988	0.974	0.987	0.977	0.989	0.982
Coomagearlahy 3 (SWS Kilgarvan Windf	110	0.000	0.000	0.000	0.000	1.011	1.011	1.017	1.011	1.007	1.004	1.013	1.001	1.007	0.996	1.006	0.997	0.996	0.987	0.988	0.974	0.987	0.977	0.989	0.982
Clahane Wind Farm (Pallas Wind Farm L	110	1.003	1.002	1.003	1.004	1.000	1.002	1.008	1.003	0.998	0.996	1.003	0.994	0.999	0.991	1.000	0.992	0.991	0.983	0.984	0.972	0.983	0.975	0.984	0.979
Coomacheo Wind Farm (Coomacheo Wi	110	1.012	1.006	1.013	1.008	1.010	1.007	1.016	1.007	1.006	1.002	1.011	0.999	1.004	0.994	1.003	0.995	0.995	0.984	0.986	0.970	0.986	0.973	0.989	0.979
Dublin Bay Power (Synergen)	220	0.993	0.997	0.992	0.997	0.993	0.998	0.993	0.996	0.998	1.001	0.993	0.998	0.994	0.997	0.994	0.997	0.995	0.998	0.999	1.004	0.998	1.003	0.999	1.001
Derrybrien (Gort Wind Farms Ltd.)	110	1.001	0.997	1.002	1.000	0.999	0.998	1.003	0.998	0.998	0.993	1.000	0.991	1.004	0.995	1.001	0.991	0.995	0.986	0.990	0.980	0.990	0.982	0.991	0.985
Edenderry (Edenderry Power Ltd.)	110	0.983	0.981	0.983	0.982	0.989	0.988	0.978	0.976	0.990	0.987	0.980	0.977	0.993	0.988	1.011	1.005	0.989	0.984	0.994	0.990	0.997	0.994	0.992	0.988
Cliff (ESB)	110	0.988	0.984	0.994	0.986	0.994	0.988	0.993	0.992	0.989	0.982	0.990	0.984	0.996	0.988	0.997	0.987	0.997	0.990	0.993	0.985	0.993	0.985	0.990	0.990
Cliff (ESB)	110	0.988	0.984	0.994	0.986	0.994	0.988	0.993	0.992	0.989	0.982	0.990	0.984	0.996	0.988	0.997	0.987	0.997	0.990	0.993	0.985	0.993	0.985	0.990	0.990
Cathleen's Fall (ESB)	110	0.989	0.985	0.995	0.987	0.995	0.989	0.994	0.992	0.990	0.982	0.990	0.985	0.997	0.988	0.998	0.987	0.997	0.990	0.994	0.985	0.994	0.986	0.991	0.990
Cathleen's Fall (ESB)	110	0.989	0.985	0.995	0.987	0.995	0.989	0.994	0.992	0.990	0.982	0.990	0.985	0.997	0.988	0.998	0.987	0.997	0.990	0.994	0.985	0.994	0.986	0.991	0.990
Great Island (Endesa)	110	1.022	1.019	1.022	1.020	1.021	1.020	1.021	1.018	1.020	1.017	1.020	1.013	1.022	1.015	1.021	1.014	1.020	1.012	1.020	1.011	1.020	1.013	1.022	1.015
Great Island (Endesa)	110	1.022	1.019	1.022	1.020	1.021	1.020	1.021	1.018	1.020	1.017	1.020	1.013	1.022	1.015	1.021	1.014	1.020	1.012	1.020	1.011	1.020	1.013	1.022	1.015
Great Island (Endesa)	220	1.018	1.016	1.017	1.017	1.017	1.017	1.017	1.015	1.017	1.014	1.016	1.010	1.018	1.012	1.017	1.011	1.016	1.009	1.016	1.008	1.015	1.009	1.017	1.011
Glanlee Wind Farm (Midas Energy/Everw	110	1.013	1.009	1.013	1.012	1.011	1.011	1.017	1.011	1.007	1.004	1.013	1.001	1.007	0.996	1.006	0.997	0.996	0.987	0.988	0.974	0.987	0.977	0.988	0.982
Barnesmore Wind Farm (Golagh)	110	0.989	0.981	0.996	0.984	0.994	0.984	0.991	0.987	0.986	0.975	0.986	0.977	0.994	0.980	0.994	0.979	0.996	0.983	0.991	0.979	0.992	0.980	0.990	0.985
Huntstown 2 (Viridian Power Ltd.)	220	0.989	0.993	0.988	0.993	0.989	0.993	0.989	0.993	0.995	0.998	0.990	0.995	0.992	0.995	0.991	0.994	0.993	0.996	0.998	1.004	0.996	1.001	0.996	0.999
Huntstown 1 (Huntstown Power Ltd.)	220	0.990	0.994	0.989	0.994	0.990	0.994	0.990	0.994	0.996	0.999	0.991	0.996	0.992	0.996	0.992	0.995	0.994	0.997	0.999	1.005	0.997	1.002	0.997	1.000

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Kings Mountain (Brick Mount Ltd.)	110	1.009	1.003	1.011	1.003	1.008	1.001	1.008	1.002	1.002	0.994	1.000	0.996	1.006	0.999	1.007	0.997	1.009	1.000	1.007	0.998	1.010	1.001	1.009	1.003
Inniscarra (ESB)	110	1.025	1.022	1.026	1.025	1.024	1.025	1.030	1.025	1.022	1.018	1.027	1.014	1.023	1.013	1.021	1.011	1.011	1.003	1.003	0.988	1.000	0.990	1.003	0.997
Inniscarra (ESB)	110	1.025	1.022	1.026	1.025	1.024	1.025	1.030	1.025	1.022	1.018	1.027	1.014	1.023	1.013	1.021	1.011	1.011	1.003	1.003	0.988	1.000	0.990	1.003	0.997
Caraigadrohid (ESB)	110	1.021	1.017	1.021	1.020	1.019	1.019	1.025	1.019	1.016	1.012	1.022	1.009	1.015	1.005	1.014	1.006	1.003	0.994	0.995	0.980	0.993	0.983	0.995	0.988
Liffey (ESB)	110	1.011	1.013	1.011	1.014	1.013	1.014	1.013	1.011	1.013	1.013	1.011	1.008	1.018	1.011	1.018	1.011	1.018	1.010	1.017	1.011	1.013	1.013	1.013	1.014
Liffey (ESB)	110	1.011	1.013	1.011	1.014	1.013	1.014	1.013	1.011	1.013	1.013	1.011	1.008	1.018	1.011	1.018	1.011	1.018	1.010	1.017	1.011	1.013	1.013	1.013	1.014
Liffey (ESB)	110	1.011	1.013	1.011	1.014	1.013	1.014	1.013	1.011	1.013	1.013	1.011	1.008	1.018	1.011	1.018	1.011	1.018	1.010	1.017	1.011	1.013	1.013	1.013	1.014
Lough Ree Power Ltd. (ESB)	110	0.999	0.994	0.999	0.994	0.996	0.992	1.001	0.994	0.995	0.988	0.996	0.989	0.999	0.992	0.996	0.988	1.008	0.999	0.997	0.991	0.998	0.991	0.997	0.992
Meentycat Ltd. (Airtricity)	110	0.988	0.977	0.995	0.979	0.991	0.979	0.986	0.979	0.980	0.965	0.980	0.967	0.988	0.971	0.989	0.970	0.992	0.974	0.987	0.971	0.989	0.973	0.988	0.979
Mountain Lodge (Mountain Lodge Pow	110	1.002	0.997	1.002	0.997	1.003	0.997	1.000	0.998	1.000	0.996	1.000	0.997	0.998	0.996	0.998	0.995	1.000	0.997	1.001	1.002	1.003	1.001	1.002	1.000
Moneypoint (ESB)***	380	0.988	0.994	0.986	0.994	0.985	0.992	0.990	0.993	0.988	0.992	0.989	0.992	0.991	0.993	0.992	0.993	0.989	0.992	0.986	0.989	0.986	0.989	0.984	0.988
Moneypoint (ESB)***	380	0.988	0.994	0.986	0.994	0.985	0.992	0.990	0.993	0.988	0.992	0.989	0.992	0.991	0.993	0.992	0.993	0.989	0.992	0.986	0.989	0.986	0.989	0.984	0.988
Moneypoint (ESB)***	380	0.988	0.994	0.986	0.994	0.985	0.992	0.990	0.993	0.988	0.992	0.989	0.992	0.991	0.993	0.992	0.993	0.989	0.992	0.986	0.989	0.986	0.989	0.984	0.988
Marina (ESB)	110	1.029	1.025	1.029	1.027	1.027	1.027	1.035	1.028	1.027	1.022	1.031	1.017	1.030	1.018	1.028	1.017	1.019	1.008	1.013	0.995	1.011	0.998	1.014	1.004
North Wall (ESB)***	110	0.991	0.995	0.990	0.994	0.991	0.995	0.991	0.994	0.996	0.999	0.991	0.996	0.993	0.996	0.993	0.995	0.995	0.997	0.999	1.005	0.997	1.002	0.997	1.000
North Wall (ESB)	220	0.991	0.995	0.989	0.994	0.990	0.995	0.991	0.994	0.996	0.999	0.991	0.996	0.993	0.996	0.992	0.995	0.994	0.997	0.999	1.005	0.997	1.002	0.997	1.000
Poolbeg (ESB)	220	0.995	0.998	0.993	0.998	0.994	0.999	0.994	0.997	0.999	1.002	0.994	0.999	0.996	0.998	0.995	0.998	0.997	0.999	1.001	1.005	0.999	1.004	1.000	1.002
Poolbeg (ESB)	220	0.995	0.998	0.993	0.998	0.994	0.999	0.994	0.997	0.999	1.002	0.994	0.999	0.996	0.998	0.995	0.998	0.997	0.999	1.001	1.005	0.999	1.004	1.000	1.002
Poolbeg (ESB)	220	0.995	0.998	0.993	0.998	0.994	0.999	0.994	0.997	0.999	1.002	0.994	0.999	0.996	0.998	0.995	0.998	0.997	0.999	1.001	1.005	0.999	1.004	1.000	1.002
Poolbeg/Shellybanks (ESB)***	220	0.992	0.993	0.992	0.993	0.992	0.994	0.992	0.993	0.994	0.995	0.992	0.997	0.994	0.997	0.994	0.996	0.995	0.998	0.999	1.004	0.997	1.003	0.998	1.001
Rhode PCP (Endesa)	110	1.005	1.006	1.004	1.005	1.005	1.006	1.002	1.004	1.007	1.008	1.002	1.005	1.000	1.001	1.003	1.004	1.000	1.001	1.004	1.006	1.006	1.006	1.005	1.004
Rhode PCP (Endesa)	110	1.005	1.006	1.004	1.005	1.005	1.006	1.002	1.004	1.007	1.008	1.002	1.005	1.000	1.001	1.003	1.004	1.000	1.001	1.004	1.006	1.006	1.006	1.005	1.004
Sealrock (Aughinish Allumina Ltd.)	110	0.994	0.994	0.995	0.997	0.992	0.995	1.000	0.997	0.991	0.991	0.997	0.990	0.995	0.988	1.002	0.995	0.988	0.981	0.978	0.968	0.977	0.970	0.978	0.973
Sealrock (Aughinish Allumina Ltd.)	110	0.994	0.994	0.995	0.997	0.992	0.995	1.000	0.997	0.991	0.991	0.997	0.990	0.995	0.988	1.002	0.995	0.988	0.981	0.978	0.968	0.977	0.970	0.978	0.973
Tarbert (Endesa)	110	0.998	1.000	0.998	1.002	0.995	1.000	1.004	1.002	0.994	0.996	0.999	0.994	0.997	0.992	0.999	0.994	0.990	0.985	0.982	0.975	0.981	0.976	0.981	0.979
Tarbert (Endesa)	110	0.998	1.000	0.998	1.002	0.995	1.000	1.004	1.002	0.994	0.996	0.999	0.994	0.997	0.992	0.999	0.994	0.990	0.985	0.982	0.975	0.981	0.976	0.981	0.979
Tarbert (Endesa)	220	1.000	1.002	1.000	1.003	0.997	1.002	1.005	1.003	0.996	0.997	1.001	0.996	1.000	0.994	1.000	0.996	0.993	0.987	0.985	0.977	0.984	0.979	0.984	0.982
Tarbert (Endesa)	220	1.000	1.002	1.000	1.003	0.997	1.002	1.005	1.003	0.996	0.997	1.001	0.996	1.000	0.994	1.000	0.996	0.993	0.987	0.985	0.977	0.984	0.979	0.984	0.982
Turlough Hill (ESB)	220	0.994	1.001	0.993	1.001	0.994	1.001	0.994	1.000	0.998	1.003	0.994	1.001	0.996	1.001	0.996	1.002	0.997	1.002	0.999	1.006	0.999	1.005	0.999	1.004
Turlough Hill (ESB)	220	0.994	1.001	0.993	1.001	0.994	1.001	0.994	1.000	0.998	1.003	0.994	1.001	0.996	1.001	0.996	1.002	0.997	1.002	0.999	1.006	0.999	1.005	0.999	1.004
Turlough Hill (ESB)	220	0.994	1.001	0.993	1.001	0.994	1.001	0.994	1.000	0.998	1.003	0.994	1.001	0.996	1.001	0.996	1.002	0.997	1.002	0.999	1.006	0.999	1.005	0.999	1.004
Turlough Hill (ESB)	220	0.994	1.001	0.993	1.001	0.994	1.001	0.994	1.000	0.998	1.003	0.994	1.001	0.996	1.001	0.996	1.002	0.997	1.002	0.999	1.006	0.999	1.005	0.999	1.004
Tynagh CCGT (Tynagh Energy Ltd.)	220	0.984	0.992	0.983	0.992	0.981	0.988	0.989	0.991	0.986	0.989	0.983	0.990	0.986	0.992	0.987	0.991	0.986	0.990	0.984	0.993	0.985	0.992	0.983	0.990

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
West Offaly Power (ESB)	110	1.001	0.998	1.001	1.000	0.999	0.998	1.001	0.997	0.998	0.995	1.000	0.993	1.008	1.002	1.000	0.993	0.997	0.990	0.994	0.987	0.995	0.989	0.996	0.991
Arklow Banks (Arklow Energy Ltd.)	110	1.003	1.004	1.002	1.004	1.003	1.005	1.002	1.003	1.006	1.006	1.002	1.003	1.003	1.003	1.003	1.002	1.003	1.003	1.007	1.007	1.006	1.007	1.007	1.006
Arthurstown Landfill Phase 2 (Irish Po	110	1.003	1.004	1.002	1.004	1.004	1.005	1.001	1.001	1.006	1.006	1.001	1.002	1.005	1.004	1.008	1.007	1.005	1.004	1.009	1.009	1.009	1.010	1.009	1.008
Arthurstown Landfill Phase 3 (Irish Po	110	1.003	1.004	1.002	1.004	1.004	1.005	1.001	1.001	1.006	1.006	1.001	1.002	1.005	1.004	1.008	1.007	1.005	1.004	1.009	1.009	1.009	1.010	1.009	1.008
Arthurstown Landfill Phase 1 & 4 (Irish	110	1.003	1.004	1.002	1.004	1.004	1.005	1.001	1.001	1.006	1.006	1.001	1.002	1.005	1.004	1.008	1.007	1.005	1.004	1.009	1.009	1.009	1.010	1.009	1.008
Glanta Commons (Ballybane Wind Far	110	1.031	1.024	1.032	1.027	1.029	1.026	1.034	1.025	1.025	1.015	1.030	1.010	1.027	1.009	1.025	1.009	1.016	0.999	1.009	0.986	1.008	0.991	1.011	0.999
Beale Hill Wind Farm (First Electric Ltd	110	1.001	1.000	1.001	1.002	0.998	1.001	1.005	1.001	0.995	0.995	1.001	0.993	0.997	0.990	0.998	0.991	0.989	0.982	0.982	0.972	0.981	0.974	0.981	0.977
Beam Hill (Beam Wind Ltd.)	110	0.988	0.973	0.995	0.976	0.987	0.972	0.981	0.972	0.973	0.956	0.973	0.958	0.983	0.963	0.983	0.961	0.987	0.964	0.983	0.963	0.985	0.965	0.984	0.972
Bruree Hydro (Slievereagh Power Ltd.	110	1.026	1.020	1.026	1.023	1.024	1.022	1.028	1.021	1.019	1.014	1.024	1.011	1.024	1.011	1.024	1.011	1.015	1.002	1.007	0.990	1.006	0.993	1.009	0.998
Cark Wind Farm	110	0.992	0.979	0.999	0.982	0.995	0.982	0.990	0.982	0.984	0.968	0.983	0.969	0.992	0.974	0.993	0.972	0.996	0.976	0.992	0.973	0.994	0.976	0.992	0.982
Curabwee Wind Farm (Galeforce Ener	110	1.033	1.026	1.033	1.029	1.031	1.028	1.035	1.028	1.027	1.018	1.032	1.013	1.028	1.011	1.026	1.011	1.017	1.001	1.010	0.988	1.008	0.993	1.011	1.000
Carnsore (Hibernian)	110	1.030	1.022	1.029	1.023	1.029	1.024	1.027	1.020	1.027	1.018	1.025	1.013	1.022	1.013	1.021	1.012	1.021	1.011	1.023	1.012	1.023	1.014	1.025	1.017
Flughland Windfarm (SWS Green Ener	110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.973	0.956	0.973	0.958	0.983	0.963	0.983	0.961	0.987	0.964	0.983	0.963	0.985	0.965	0.984	0.972
Gartnaneane (Gartnaneane Ltd./Airtric	110	0.997	0.995	0.998	0.995	0.999	0.996	0.996	0.996	0.998	0.997	0.997	0.999	0.997	0.999	0.997	0.999	1.000	1.002	1.003	1.009	1.004	1.007	1.004	1.005
Knockawarriga Wind Farm	110	1.001	1.000	1.001	1.002	0.998	1.001	1.005	1.001	0.995	0.995	1.001	0.993	0.997	0.990	0.998	0.991	0.989	0.982	0.982	0.972	0.981	0.974	0.981	0.977
Liffey (ESB)**	-	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Meenachullalan (Airoishin Wind Energ	110	0.988	0.982	0.994	0.984	0.993	0.985	0.992	0.989	0.987	0.978	0.988	0.980	0.995	0.984	0.996	0.983	0.997	0.986	0.993	0.982	0.993	0.983	0.991	0.987
Moanmore (Kilrush Energy Ltd.)	110	1.018	1.013	1.019	1.016	1.017	1.015	1.022	1.015	1.014	1.008	1.017	1.005	1.016	1.004	1.015	1.004	1.010	0.997	1.002	0.989	1.002	0.991	1.003	0.995
Muingnaminnane (Muingnaminnane W	110	1.009	1.006	1.009	1.009	1.006	1.007	1.013	1.008	1.003	1.000	1.008	0.997	1.004	0.995	1.005	0.996	0.996	0.987	0.989	0.975	0.988	0.979	0.989	0.983
Raheen Barr (Matrix Energy)	110	1.022	1.014	1.023	1.016	1.020	1.012	1.024	1.012	1.017	1.005	1.011	1.004	1.017	1.007	1.019	1.005	1.022	1.007	1.018	1.007	1.022	1.010	1.022	1.012
Richfield (Richfield Windfarm (ROI) Ltd	110	1.030	1.022	1.029	1.023	1.029	1.024	1.027	1.020	1.027	1.018	1.025	1.013	1.022	1.013	1.021	1.012	1.021	1.011	1.023	1.012	1.023	1.014	1.025	1.017
Culliagh (Dedondo Ltd.)	110	0.992	0.979	0.999	0.982	0.995	0.982	0.990	0.982	0.984	0.968	0.983	0.969	0.992	0.974	0.993	0.972	0.996	0.976	0.992	0.973	0.994	0.976	0.992	0.982
Sorne Hill (Sorne Wind Ltd.)	110	0.988	0.973	0.995	0.976	0.987	0.972	0.981	0.972	0.973	0.956	0.973	0.958	0.983	0.963	0.983	0.961	0.987	0.964	0.983	0.963	0.985	0.965	0.984	0.972
Tournafulla 2 (Tournafulla Wind Farm L	110	1.001	1.000	1.001	1.002	0.998	1.001	1.005	1.001	0.995	0.995	1.001	0.993	0.997	0.990	0.998	0.991	0.989	0.982	0.982	0.972	0.981	0.974	0.981	0.977
Tawnaghmore PCP (Endesa)***	110	1.025	1.015	1.027	1.016	1.023	1.013	1.023	1.013	1.014	1.002	1.008	1.005	1.019	1.009	1.023	1.007	1.024	1.010	1.021	1.006	1.027	1.012	1.026	1.015
Tawnaghmore PCP (Endesa)***	110	1.025	1.015	1.027	1.016	1.023	1.013	1.023	1.013	1.014	1.002	1.008	1.005	1.019	1.009	1.023	1.007	1.024	1.010	1.021	1.006	1.027	1.012	1.026	1.015
Taurbeg (Taurbeg Ltd.)	110	1.025	1.018	1.025	1.021	1.023	1.020	1.027	1.019	1.018	1.012	1.023	1.008	1.023	1.008	1.022	1.008	1.014	0.999	1.006	0.987	1.005	0.991	1.008	0.996
Tursillagh 2 (Saorgus Energy Ltd.)	110	1.009	1.006	1.009	1.009	1.006	1.007	1.013	1.008	1.003	1.000	1.008	0.997	1.004	0.995	1.005	0.996	0.996	0.987	0.989	0.975	0.988	0.979	0.989	0.983
Tursillagh 1 (Saorgus Energy Ltd.)	110	1.009	1.006	1.009	1.009	1.006	1.007	1.013	1.008	1.003	1.000	1.008	0.997	1.004	0.995	1.005	0.996	0.996	0.987	0.989	0.975	0.988	0.979	0.989	0.983
Antrim	110	0.985	0.984	0.986	0.983	0.988	0.985	0.984	0.987	0.985	0.987	0.988	0.992	0.985	0.991	0.986	0.991	0.989	0.997	0.992	1.003	0.994	1.000	0.993	0.997
Ballylumford	110	0.978	0.982	0.980	0.981	0.980	0.981	0.978	0.984	0.980	0.985	0.983	0.989	0.981	0.989	0.981	0.988	0.985	0.994	0.988	1.002	0.988	0.998	0.987	0.994
Ballylumford	275	0.983	0.983	0.984	0.982	0.985	0.983	0.981	0.985	0.983	0.986	0.986	0.991	0.983	0.990	0.983	0.989	0.987	0.995	0.990	1.003	0.991	0.999	0.990	0.995

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Ballymena	110	0.988	0.986	0.989	0.985	0.991	0.986	0.986	0.988	0.987	0.989	0.990	0.994	0.987	0.992	0.988	0.992	0.991	0.998	0.995	1.005	0.996	1.002	0.995	0.998
Banbridge	110	0.995	0.993	0.996	0.992	0.996	0.992	0.993	0.994	0.994	0.994	0.995	0.997	0.993	0.997	0.994	0.996	0.997	1.001	1.001	1.008	1.002	1.006	1.001	1.003
Ballyvallagh	110	0.982	0.983	0.982	0.982	0.984	0.982	0.980	0.985	0.982	0.986	0.985	0.990	0.983	0.989	0.983	0.989	0.987	0.995	0.990	1.002	0.991	0.999	0.989	0.995
Ballynahinch	110	0.996	0.992	0.996	0.991	0.998	0.992	0.993	0.994	0.994	0.994	0.996	0.997	0.994	0.997	0.994	0.996	0.998	1.002	1.002	1.010	1.005	1.007	1.004	1.004
Carnmoney	110	0.988	0.988	0.989	0.987	0.990	0.987	0.987	0.990	0.988	0.990	0.990	0.994	0.988	0.993	0.988	0.993	0.993	0.999	0.996	1.007	0.997	1.003	0.996	1.000
Castlereagh	110	0.992	0.990	0.993	0.989	0.994	0.990	0.990	0.991	0.991	0.992	0.993	0.996	0.991	0.995	0.991	0.995	0.995	1.000	0.999	1.007	1.000	1.005	0.999	1.001
Castlereagh	275	0.989	0.988	0.990	0.987	0.991	0.988	0.987	0.990	0.989	0.990	0.991	0.994	0.989	0.993	0.989	0.993	0.992	0.999	0.996	1.005	0.997	1.003	0.996	0.999
Belast Central	110	0.992	0.990	0.993	0.989	0.994	0.990	0.990	0.992	0.992	0.992	0.993	0.996	0.991	0.995	0.992	0.995	0.995	1.001	0.999	1.008	1.001	1.005	1.000	1.002
Coleraine	110	0.989	0.984	0.989	0.982	0.990	0.982	0.983	0.983	0.983	0.986	0.990	0.994	0.983	0.992	0.983	0.991	0.989	0.998	0.992	1.006	0.994	1.002	0.993	0.999
Coolkeeragh	110	0.977	0.976	0.977	0.973	0.981	0.977	0.975	0.979	0.976	0.983	0.985	0.995	0.977	0.992	0.976	0.991	0.982	0.997	0.985	1.004	0.985	1.000	0.984	0.996
Coolkeeragh	275	0.978	0.978	0.978	0.975	0.982	0.978	0.977	0.980	0.977	0.984	0.985	0.994	0.979	0.992	0.978	0.991	0.983	0.997	0.986	1.004	0.986	1.000	0.985	0.997
Creagh	110	0.988	0.986	0.989	0.985	0.990	0.986	0.986	0.988	0.987	0.989	0.990	0.994	0.987	0.992	0.987	0.992	0.991	0.998	0.994	1.004	0.995	1.001	0.994	0.998
Cregagh	110	0.992	0.990	0.993	0.989	0.994	0.990	0.990	0.992	0.992	0.992	0.993	0.996	0.991	0.995	0.992	0.995	0.995	1.001	0.999	1.008	1.001	1.005	1.000	1.001
Donegal	110	0.990	0.989	0.991	0.988	0.992	0.989	0.988	0.991	0.990	0.991	0.992	0.995	0.990	0.994	0.990	0.994	0.994	1.000	0.997	1.007	0.999	1.004	0.998	1.000
Drumnakelly	110	0.993	0.991	0.994	0.991	0.995	0.991	0.991	0.993	0.993	0.993	0.994	0.997	0.992	0.996	0.992	0.995	0.996	1.001	0.999	1.007	1.000	1.005	1.000	1.002
Dungannon	110	0.991	0.988	0.992	0.987	0.993	0.988	0.988	0.990	0.989	0.991	0.992	0.996	0.989	0.994	0.988	0.993	0.993	0.999	0.995	1.004	0.996	1.002	0.996	0.999
Eden	110	0.984	0.986	0.986	0.985	0.986	0.985	0.983	0.988	0.985	0.988	0.987	0.992	0.986	0.992	0.985	0.991	0.990	0.997	0.993	1.005	0.994	1.001	0.992	0.997
Enniskillen	110	0.998	0.985	0.998	0.985	1.000	0.986	0.991	0.985	0.991	0.986	0.996	0.992	0.985	0.988	0.985	0.985	0.991	0.992	0.990	0.994	0.993	0.994	0.993	0.990
Aghyoule	110	0.998	0.983	0.999	0.983	1.001	0.984	0.990	0.983	0.990	0.983	0.995	0.989	0.982	0.982	0.981	0.979	0.988	0.986	0.986	0.989	0.990	0.988	0.989	0.985
Finaghy	110	0.990	0.988	0.991	0.988	0.992	0.988	0.988	0.990	0.990	0.991	0.991	0.995	0.990	0.994	0.990	0.993	0.993	0.999	0.997	1.006	0.999	1.004	0.998	1.000
Glengormley	110	0.998	0.984	0.998	0.984	1.000	0.985	0.990	0.984	0.990	0.985	0.995	0.990	0.983	0.985	0.983	0.982	0.989	0.989	0.988	0.991	0.991	0.991	0.991	0.987
Hannahstown	110	0.990	0.988	0.991	0.988	0.992	0.988	0.988	0.990	0.990	0.991	0.991	0.994	0.989	0.994	0.989	0.993	0.993	0.999	0.997	1.006	0.998	1.003	0.997	1.000
Hannahstown	275	0.988	0.987	0.989	0.986	0.990	0.987	0.986	0.989	0.988	0.989	0.990	0.993	0.988	0.993	0.988	0.992	0.991	0.998	0.995	1.005	0.996	1.002	0.995	0.998
Kells	110	0.985	0.984	0.985	0.983	0.987	0.984	0.983	0.986	0.984	0.987	0.987	0.992	0.985	0.991	0.985	0.991	0.988	0.996	0.991	1.003	0.993	1.000	0.992	0.996
Kells	275	0.984	0.984	0.985	0.983	0.986	0.984	0.983	0.986	0.984	0.987	0.987	0.992	0.985	0.991	0.985	0.991	0.988	0.996	0.991	1.003	0.993	1.000	0.992	0.996
Kilroot	275	0.984	0.984	0.985	0.984	0.986	0.984	0.983	0.987	0.984	0.987	0.987	0.991	0.985	0.991	0.985	0.991	0.988	0.996	0.991	1.002	0.992	0.999	0.992	0.996
Knock	110	0.992	0.990	0.993	0.989	0.994	0.990	0.990	0.992	0.992	0.992	0.994	0.996	0.991	0.995	0.992	0.995	0.995	1.001	0.999	1.008	1.001	1.005	1.000	1.002
Larne	110	0.982	0.983	0.983	0.982	0.984	0.982	0.981	0.985	0.982	0.986	0.985	0.990	0.983	0.989	0.983	0.989	0.987	0.995	0.990	1.002	0.991	0.999	0.990	0.995
Limavady	110	0.984	0.980	0.984	0.978	0.986	0.979	0.979	0.981	0.980	0.984	0.987	0.993	0.980	0.991	0.980	0.990	0.986	0.997	0.989	1.004	0.990	1.000	0.990	0.997
Lisburn	110	0.993	0.990	0.993	0.990	0.994	0.990	0.990	0.992	0.992	0.992	0.994	0.996	0.992	0.995	0.992	0.995	0.996	1.001	0.999	1.008	1.001	1.005	1.000	1.002
Lisaghmore	110	0.978	0.977	0.978	0.974	0.982	0.977	0.976	0.979	0.976	0.983	0.986	0.995	0.978	0.993	0.977	0.991	0.983	0.998	0.985	1.004	0.985	1.000	0.984	0.996
Loguestown	110	0.990	0.985	0.990	0.983	0.991	0.982	0.983	0.984	0.984	0.986	0.990	0.995	0.984	0.993	0.984	0.992	0.990	0.998	0.993	1.006	0.994	1.003	0.994	0.999
Magherafelt	275	0.984	0.984	0.985	0.982	0.986	0.983	0.983	0.986	0.984	0.987	0.987	0.993	0.984	0.992	0.984	0.991	0.988	0.997	0.991	1.004	0.992	1.000	0.991	0.997
Moyle (Ballycronan More)*	275	0.983	0.983	0.984	0.982	0.985	0.983	0.981	0.985	0.983	0.986	0.986	0.991	0.984	0.990	0.983	0.989	0.987	0.995	0.990	1.003	0.992	0.999	0.990	0.995

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Newtownards	110	0.994	0.991	0.995	0.990	0.996	0.991	0.992	0.993	0.993	0.993	0.995	0.997	0.992	0.996	0.993	0.996	0.997	1.002	1.001	1.009	1.003	1.006	1.002	1.003
Newry	110	1.000	0.996	1.000	0.996	1.001	0.996	0.997	0.997	0.998	0.997	0.999	1.000	0.997	0.999	0.998	0.999	1.002	1.004	1.005	1.012	1.007	1.009	1.007	1.006
Omagh	110	0.990	0.983	0.990	0.982	0.992	0.983	0.985	0.984	0.985	0.986	0.991	0.993	0.983	0.990	0.983	0.988	0.989	0.995	0.987	0.996	0.989	0.994	0.988	0.991
Rathgael	110	0.995	0.992	0.996	0.991	0.998	0.992	0.993	0.994	0.994	0.994	0.996	0.997	0.993	0.997	0.994	0.996	0.998	1.002	1.002	1.010	1.005	1.007	1.004	1.004
Rosebank	110	0.992	0.990	0.993	0.989	0.994	0.990	0.990	0.991	0.991	0.992	0.993	0.996	0.991	0.995	0.991	0.995	0.995	1.000	0.999	1.007	1.000	1.005	1.000	1.001
Slieve Kirk	110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.982	1.000	0.982	0.996	0.982	0.993
Slieve Kirk T-Off	110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.984	1.002	0.984	0.998	0.984	0.995
Springtown	110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.986	1.005	0.986	1.001	0.985	0.997
Strabane	110	0.980	0.978	0.981	0.975	0.985	0.978	0.978	0.980	0.978	0.984	0.987	0.994	0.979	0.992	0.978	0.990	0.984	0.997	0.985	1.002	0.985	0.998	0.985	0.995
Tandragee	110	0.992	0.991	0.993	0.990	0.994	0.991	0.991	0.992	0.992	0.993	0.993	0.996	0.992	0.996	0.992	0.995	0.995	1.000	0.998	1.006	1.000	1.004	0.999	1.001
Tandragee	275	0.991	0.990	0.991	0.990	0.992	0.990	0.989	0.992	0.991	0.992	0.992	0.996	0.991	0.995	0.991	0.994	0.994	0.999	0.997	1.005	0.998	1.003	0.998	1.000
Tamnamore	110	0.988	0.986	0.989	0.985	0.990	0.986	0.986	0.988	0.987	0.989	0.990	0.994	0.986	0.993	0.986	0.992	0.990	0.998	0.993	1.003	0.994	1.001	0.993	0.997
Tamnamore	275	0.983	0.983	0.984	0.981	0.986	0.982	0.982	0.985	0.983	0.986	0.987	0.993	0.983	0.991	0.983	0.991	0.987	0.997	0.990	1.003	0.991	1.000	0.990	0.996
Waringstown	110	0.995	0.993	0.996	0.992	0.996	0.993	0.993	0.994	0.994	0.994	0.995	0.998	0.993	0.997	0.994	0.996	0.997	1.001	1.000	1.008	1.002	1.006	1.001	1.003
West Belfast Central	110	0.991	0.989	0.992	0.988	0.993	0.989	0.989	0.991	0.991	0.992	0.993	0.995	0.990	0.994	0.990	0.994	0.994	1.000	0.998	1.007	0.999	1.004	0.998	1.000

2008 Compression Factor TLAF																									
		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
Unit	kV	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Aghada (ESB)	220kV	1.018	1.023	1.020	1.024	1.022	1.027	1.019	1.030	1.028	1.033	1.040	1.031	1.037	1.028	1.026	1.029	1.027	1.028	1.023	1.022	1.023	1.024	1.018	1.024
Aghada PCP (ESB)	110kV	1.020	1.024	1.021	1.025	1.023	1.029	1.019	1.031	1.029	1.035	1.041	1.032	1.038	1.030	1.026	1.030	1.027	1.029	1.024	1.023	1.024	1.026	1.019	1.026
Ardnacrusha (ESB)	110kV	1.004	1.004	1.005	1.006	1.011	1.013	1.019	1.024	1.028	1.027	1.036	1.023	1.035	1.022	1.028	1.023	1.026	1.020	1.016	1.010	1.010	1.009	1.006	1.008
Ballywater (Ballywater Windfarms Ltd.)	110kV	1.023	1.018	1.023	1.019	1.020	1.016	1.018	1.015	1.020	1.014	1.021	1.012	1.020	1.012	1.021	1.014	1.023	1.014	1.025	1.017	1.028	1.020	1.025	1.021
Barnesmore Wind Farm (Golagh)	110kV	0.987	0.968	0.990	0.982	0.983	0.975	0.984	0.983	0.991	0.979	0.991	0.977	0.990	0.976	0.993	0.977	0.990	0.976	0.984	0.976	0.987	0.979	0.983	0.971
Booltiagh (Booltiagh Windfarm Ltd.)	110kV	1.003	1.003	1.004	1.005	1.010	1.010	1.016	1.016	1.024	1.020	1.030	1.016	1.030	1.015	1.024	1.017	1.021	1.013	1.014	1.007	1.008	1.006	1.004	1.007
Clahane (Pallas Windfarm Ltd.)**	110kV															1.018	1.021	1.016	1.017	1.004	1.002	0.995	1.003	0.993	1.007
Coomacheo (Coomacheo Windfarm Ltd	110kV											1.023	1.016	1.022	1.016	1.013	1.015	1.014	1.012	1.004	1.002	0.999	1.004	1.001	1.011
Coomagearlahy (SWS Kilgarvan Windfa	110kV	0.999	1.004	1.001	1.006	1.006	1.010	1.011	1.017	1.020	1.019	1.026	1.017	1.024	1.014	1.016	1.015	1.016	1.012	1.008	1.002	1.002	1.004	1.004	1.012
Derrybrien (Gort Windfarms Ltd.)	110kV	0.994	0.991	0.995	0.992	1.000	0.997	1.004	1.005	1.009	1.003	1.014	1.002	1.017	1.007	1.011	1.003	1.008	0.999	1.004	0.995	0.998	0.993	0.995	0.994
Dublin Bay Power (Synergen)	220kV	0.992	0.998	0.991	0.998	0.991	0.997	0.990	0.995	0.991	0.996	0.991	0.996	0.991	0.997	0.993	0.998	0.993	0.998	0.995	1.001	0.996	1.000	0.995	1.001
Edenderry (Edenderry Power Ltd.)	110kV	0.985	0.976	0.979	0.967	0.982	0.970	0.981	0.981	0.980	0.973	0.986	0.976	1.014	1.012	0.983	0.975	0.990	0.979	0.989	0.980	0.986	0.972	0.984	0.972
Erne (ESB)	110kV	0.987	0.972	0.989	0.986	0.984	0.981	0.986	0.989	0.994	0.986	0.995	0.984	0.994	0.985	0.997	0.985	0.993	0.984	0.986	0.983	0.988	0.985	0.984	0.976
Erne (ESB)	110kV	0.989	0.973	0.990	0.987	0.984	0.981	0.987	0.989	0.994	0.986	0.995	0.984	0.994	0.985	0.997	0.985	0.993	0.984	0.987	0.983	0.989	0.985	0.985	0.976
Glanlee Wind Farm	110kV	0.999	1.004	1.001	1.006	1.006	1.010	1.011	1.016	1.020	1.019	1.026	1.017	1.024	1.014	1.016	1.015	1.016	1.012	1.008	1.002	1.002	1.004	1.004	1.012
Great Island (ESB)	110kV	1.019	1.020	1.020	1.021	1.019	1.021	1.017	1.019	1.020	1.021	1.024	1.020	1.023	1.018	1.021	1.020	1.022	1.020	1.023	1.020	1.025	1.022	1.021	1.023
Great Island (ESB)	220kV	1.015	1.016	1.015	1.017	1.015	1.017	1.013	1.016	1.017	1.018	1.020	1.016	1.020	1.016	1.017	1.017	1.018	1.017	1.019	1.017	1.019	1.018	1.016	1.019
Huntstown (Huntstown Power Ltd.)	220kV	0.992	0.998	0.991	0.997	0.991	0.996	0.990	0.994	0.991	0.995	0.987	0.994	0.987	0.994	0.989	0.994	0.989	0.995	0.992	0.998	0.993	0.998	0.992	0.999
Huntstown 2 (Viridian Power Ltd.)	220kV	0.991	0.997	0.990	0.996	0.990	0.995	0.989	0.993	0.990	0.995	0.987	0.992	0.987	0.993	0.989	0.993	0.989	0.993	0.991	0.997	0.992	0.997	0.992	0.997
Kingsmountain (Brickmount Ltd.)	110kV	1.008	0.998	1.010	1.002	1.007	1.000	1.008	1.001	1.009	1.002	1.010	1.000	1.010	0.996	1.012	1.001	1.009	0.999	1.007	0.998	1.009	1.000	1.006	0.998
Lee (ESB)	110kV	1.014	1.018	1.016	1.021	1.020	1.024	1.021	1.028	1.030	1.031	1.039	1.029	1.037	1.025	1.027	1.026	1.029	1.025	1.022	1.017	1.019	1.019	1.011	1.018
Lee (ESB)	110kV	1.019	1.024	1.022	1.028	1.025	1.030	1.024	1.034	1.034	1.037	1.044	1.034	1.041	1.030	1.032	1.030	1.035	1.029	1.026	1.023	1.025	1.026	1.017	1.025
Liffey (ESB)	110kV	1.009	1.010	1.008	1.011	1.009	1.009	1.009	1.014	1.011	1.009	1.014	1.008	1.014	1.012	1.014	1.008	1.015	1.012	1.017	1.012	1.015	1.012	1.012	1.012
Lough Ree Power (ESB)	110kV	0.997	0.988	0.997	0.990	0.998	0.989	1.000	0.997	1.002	0.993	1.005	0.993	1.004	0.997	1.012	1.000	1.004	0.991	1.001	0.990	0.999	0.988	0.997	0.990
Marina (ESB)	110kV	1.026	1.030	1.027	1.031	1.029	1.034	1.025	1.036	1.035	1.039	1.045	1.037	1.042	1.033	1.033	1.034	1.037	1.033	1.029	1.027	1.030	1.031	1.025	1.031
Meentycat (Meentycat Ltd.)	110kV	0.986	0.961	0.988	0.975	0.978	0.966	0.979	0.975	0.985	0.969	0.985	0.966	0.984	0.966	0.987	0.967	0.985	0.966	0.980	0.967	0.984	0.970	0.979	0.962
Moneypoint (ESB)*****	380kV	0.981	0.986	0.980	0.985	0.985	0.988	0.990	0.994	0.993	0.995	0.996	0.996	0.996	0.997	0.994	0.996	0.991	0.994	0.990	0.990	0.983	0.986	0.982	0.987
Mountain Lodge (Mountain Lodge Powe	110kV							0.994	0.991	0.992	0.985	0.993	0.984	0.992	0.990	0.993	0.985	0.994	0.986	0.997	0.987	0.999	0.989	1.000	0.988
Ratrussan Windfarm (Bindoo Windfarm	110kV	1.000	0.991	1.001	0.992	0.997	0.990	0.994	0.991	0.992	0.985	0.993	0.984	0.992	0.990	0.993	0.985	0.994	0.986	0.997	0.987	0.999	0.989	1.000	0.988
North Wall (ESB)	220kV	0.993	0.999	0.992	0.998	0.992	0.997	0.991	0.995	0.992	0.996	0.988	0.994	0.988	0.994	0.990	0.995	0.990	0.995	0.992	0.998	0.993	0.998	0.993	0.999
North Wall (ESB)*****	220kV	0.993	0.999	0.992	0.998	0.992	0.997	0.991	0.995	0.992	0.996	0.988	0.994	0.988	0.994	0.990	0.995	0.990	0.995	0.992	0.998	0.993	0.998	0.993	0.999
Poolbeg (ESB)***	220kV	0.993	0.999	0.992	0.999	0.992	0.998	0.992	0.996	0.992	0.997	0.992	0.997	0.992	0.998	0.994	0.998	0.994	0.998	0.996	1.002	0.997	1.001	0.996	1.002
Poolbeg (ESB)****	220kV	0.992	0.998	0.991	0.998	0.991	0.997	0.990	0.994	0.991	0.996	0.989	0.995	0.989	0.995	0.991	0.996	0.991	0.996	0.993	0.999	0.994	0.999	0.994	1.000
Rhode PCP (ESB)	110kV	1.004	1.003	1.003	1.002	1.002	1.001	1.001	1.002	1.000	1.000	1.000	1.000	1.001	1.004	1.002	1.002	1.001	1.002	1.005	1.005	1.006	1.005	1.005	1.005
Seal Rock (Aughinish Alumina)	110kV	0.987	0.991	0.986	0.989	0.996	1.001	1.004	1.010	1.013	1.010	1.020	1.008	1.019	1.008	1.011	1.007	1.011	1.004	0.999	0.991	0.991	0.990	0.989	0.993
Tarbert (ESB)	110kV	0.984	0.994	0.985	0.994	0.995	1.002	1.007	1.014	1.017	1.018	1.022	1.014	1.021	1.012	1.013	1.014	1.011	1.009	0.999	0.995	0.989	0.994	0.986	0.996
Tarbert (ESB)	220kV	0.987	0.996	0.988	0.996	0.997	1.003	1.008	1.015	1.017	1.018	1.023	1.015	1.022	1.013	1.014	1.015	1.012	1.011	1.001	0.997	0.992	0.997	0.988	0.998

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Tawnaghmore PCP (ESB)	110kV	1.026	1.013	1.028	1.017	1.024	1.015	1.025	1.011	1.023	1.015	1.023	1.013	1.027	1.005	1.027	1.014	1.025	1.011	1.024	1.011	1.028	1.014	1.022	1.012
Turlough Hill (ESB)	220kV	0.994	0.999	0.992	0.999	0.992	0.998	0.991	0.996	0.991	0.999	0.992	0.998	0.993	1.000	0.993	0.999	0.992	1.000	0.996	1.003	0.995	1.001	0.995	1.001
Tynagh CCGT (Tynagh Energy Ltd.)	220kV	0.979	0.982	0.978	0.981	0.983	0.985	0.985	0.987	0.988	0.988	0.990	0.989	0.989	0.988	0.989	0.989	0.985	0.985	0.984	0.984	0.978	0.980	0.978	0.981
West Offaly Power (ESB)	110kV	0.995	0.992	0.994	0.991	0.999	0.997	1.001	1.003	1.004	1.000	1.007	0.999	1.014	1.008	1.008	1.003	1.004	0.997	1.002	0.996	0.998	0.993	0.996	0.994
Arklow Banks (Arklow Energy Ltd.)	110kV	1.000	1.005	1.000	1.005	0.999	1.003	0.998	1.001	0.999	1.002	1.000	1.002	0.999	1.002	1.001	1.004	1.001	1.004	1.004	1.007	1.004	1.007	1.004	1.008
Arthurstown Landfill Phase 2 (Irish Po	110kV	1.008	1.006	0.999	0.998	0.999	0.998	0.998	0.999	0.998	0.997	0.999	0.997	1.005	1.006	1.000	0.998	1.001	1.000	1.004	1.003	1.004	1.001	1.003	1.001
Arthurstown Landfill Phase 3 (Irish Po	110kV	1.008	1.006	0.999	0.998	0.999	0.998	0.998	0.999	0.998	0.997	0.999	0.997	1.005	1.006	1.000	0.998	1.001	1.000	1.004	1.003	1.004	1.001	1.003	1.001
Arthurstown Landfill Phase 1 & 4 (Irish	110kV	1.008	1.006	0.999	0.998	0.999	0.998	0.998	0.999	0.998	0.997	0.999	0.997	1.005	1.006	1.000	0.998	1.001	1.000	1.004	1.003	1.004	1.001	1.003	1.001
Glanta Commmons (Ballybane Windfa	110kV															1.034	1.028	1.037	1.027	1.031	1.020	1.029	1.024	1.022	1.024
Beam Hill (Beam Wind Ltd.)	110kV	0.986	0.957	0.989	0.970	0.978	0.962	0.978	0.970	0.983	0.964	0.982	0.960	0.981	0.960	0.985	0.961	0.983	0.960	0.979	0.961	0.985	0.966	0.979	0.958
Cark Wind Farm (RES-Gen Ltd.)	110kV	0.990	0.964	0.993	0.978	0.983	0.970	0.984	0.978	0.989	0.972	0.989	0.969	0.987	0.969	0.992	0.970	0.989	0.969	0.984	0.970	0.989	0.974	0.984	0.966
Carnsore (Hibernian)	110kV	1.029	1.022	1.029	1.023	1.026	1.021	1.023	1.019	1.025	1.019	1.027	1.017	1.026	1.015	1.026	1.018	1.028	1.018	1.031	1.020	1.034	1.023	1.030	1.024
Knockawarriga (SWS Knockawarriga W	110kV									1.024	1.023	1.025	1.019	1.024	1.012	1.016	1.017	1.014	1.013	1.001	1.000	0.993	1.001	0.989	1.001
Meenachullalan (Airoishin Wind Energ	110kV							0.984	0.985	0.991	0.982	0.992	0.980	0.991	0.979	0.994	0.980	0.990	0.980	0.984	0.979	0.987	0.982	0.983	0.974
Muingnaminnane (Muingnaminnane W	110kV											1.033	1.024	1.031	1.016	1.023	1.022	1.022	1.018	1.011	1.005	1.003	1.007	1.001	1.011
Liffey (ESB)*	-	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Culliagh (Dedondo Ltd.)	110kV	0.990	0.964	0.993	0.978	0.983	0.970	0.984	0.978	0.989	0.972	0.989	0.969	0.987	0.969	0.992	0.970	0.989	0.969	0.984	0.970	0.989	0.974	0.984	0.966
Gartnaneane (Gartnaneane Ltd.)	110kV	0.999	0.998	1.000	0.998	0.996	0.995	0.993	0.992	0.990	0.992	0.990	0.992	0.989	0.991	0.991	0.992	0.992	0.993	0.994	0.995	0.997	0.998	1.000	0.998
Moanmore (Kilrush Energy Ltd.)	110kV	1.004	1.005	1.005	1.007	1.011	1.012	1.017	1.017	1.025	1.021	1.031	1.017	1.031	1.016	1.025	1.018	1.022	1.015	1.014	1.008	1.009	1.008	1.005	1.008
Raheen Barr (Matrix Energy Partnersh	110kV	1.025	1.023	1.025	1.026	1.023	1.025	1.027	1.016	1.029	1.025	1.029	1.023	1.028	1.010	1.030	1.023	1.028	1.020	1.027	1.019	1.026	1.023	1.018	1.019
Richfield (Richfield Windfarm (ROI) Ltd	110kV	1.029	1.022	1.029	1.023	1.026	1.021	1.023	1.019	1.025	1.019	1.027	1.017	1.026	1.015	1.026	1.018	1.028	1.018	1.031	1.020	1.034	1.023	1.030	1.024
Sorne Hill (Sorne Wind Ltd.)	110kV	0.986	0.957	0.989	0.970	0.978	0.962	0.978	0.970	0.983	0.964	0.982	0.960	0.981	0.960	0.985	0.961	0.983	0.960	0.979	0.961	0.985	0.966	0.979	0.958
Taurbeg (Taurbeg Ltd.)	110kV	1.021	1.015	1.022	1.018	1.022	1.018	1.024	1.028	1.032	1.027	1.040	1.023	1.038	1.023	1.031	1.022	1.033	1.020	1.026	1.013	1.023	1.014	1.018	1.014
Tournafulla Phase 2 (Airtricity)**	110kV					1.002	1.009	1.014	1.018	1.024	1.023	1.025	1.019	1.024	1.012	1.016	1.017	1.014	1.013	1.001	1.000	0.993	1.001	0.989	1.001
Tursillagh 1 (Saorgus Energy Ltd.)	110kV	1.001	1.007	1.002	1.009	1.010	1.015	1.020	1.021	1.030	1.027	1.033	1.024	1.031	1.016	1.023	1.022	1.022	1.018	1.011	1.005	1.003	1.007	1.001	1.011
Tursillagh 2 (Saorgus Energy Ltd.)	110kV	1.001	1.007	1.002	1.009	1.010	1.015	1.020	1.021	1.030	1.027	1.033	1.024	1.031	1.016	1.023	1.022	1.022	1.018	1.011	1.005	1.003	1.007	1.001	1.011
Antrim	110kV	0.994	0.992	0.996	0.991	0.991	0.988	0.986	0.985	0.983	0.985	0.980	0.984	0.979	0.983	0.980	0.983	0.982	0.986	0.983	0.987	0.989	0.990	0.995	0.989
Antrim	110kV	0.994	0.992	0.996	0.991	0.991	0.988	0.986	0.985	0.983	0.985	0.980	0.984	0.979	0.983	0.980	0.983	0.982	0.986	0.983	0.987	0.989	0.990	0.995	0.989
Ballylumford	110kV	0.987	0.986	0.989	0.986	0.984	0.983	0.977	0.979	0.975	0.979	0.977	0.981	0.975	0.980	0.975	0.979	0.975	0.981	0.976	0.982	0.982	0.985	0.988	0.984
Ballylumford	275kV	0.990	0.988	0.992	0.988	0.987	0.985	0.981	0.982	0.978	0.981	0.977	0.981	0.976	0.981	0.977	0.980	0.978	0.983	0.979	0.984	0.985	0.986	0.991	0.986
Ballymena	110kV	0.997	0.994	0.999	0.993	0.994	0.990	0.989	0.987	0.985	0.986	0.982	0.985	0.981	0.984	0.982	0.984	0.984	0.987	0.986	0.989	0.992	0.992	0.998	0.991
Ballymena	110kV	0.997	0.994	0.999	0.993	0.994	0.990	0.989	0.987	0.985	0.986	0.982	0.985	0.981	0.984	0.982	0.984	0.984	0.987	0.986	0.989	0.992	0.992	0.998	0.991
Banbridge	110kV	1.001	0.998	1.003	0.997	0.998	0.995	0.994	0.992	0.991	0.991	0.989	0.991	0.988	0.990	0.990	0.990	0.991	0.992	0.993	0.994	0.998	0.996	1.002	0.996
Banbridge	110kV	1.001	0.998	1.003	0.997	0.998	0.995	0.994	0.992	0.991	0.991	0.989	0.991	0.988	0.990	0.990	0.990	0.991	0.992	0.993	0.994	0.998	0.996	1.002	0.996
Ballyvallagh	110kV	0.990	0.989	0.993	0.989	0.988	0.985	0.982	0.982	0.979	0.982	0.979	0.982	0.977	0.981	0.978	0.981	0.979	0.983	0.980	0.985	0.985	0.987	0.991	0.987
Ballynahinch	110kV	1.004	1.004	1.006	1.006	1.000	0.995	0.995	0.992	0.991	0.991	0.989	0.990	0.988	0.989	0.989	0.989	0.992	0.992	0.994	0.994	1.000	0.997	1.005	0.997
Ballynahinch	110kV	1.004	1.003	1.006	1.002	1.000	0.995	0.995	0.992	0.991	0.991	0.989	0.990	0.988	0.989	0.989	0.989	0.992	0.992	0.994	0.994	1.000	0.997	1.005	0.997

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Cables at Coolkerragh	275kV	0.987	0.989	0.989	0.989	0.986	0.987	0.986	0.987	0.974	0.982	0.971	0.983	0.969	0.982	0.973	0.983	0.974	0.986	0.976	0.986	0.981	0.988	0.986	0.986
Cables at Coolkerragh	275kV	0.987	0.989	0.989	0.989	0.986	0.987	0.986	0.987	0.974	0.982	0.971	0.983	0.969	0.982	0.973	0.983	0.974	0.986	0.976	0.986	0.981	0.988	0.986	0.986
Carnmoney	110kV	0.996	0.993	0.998	0.992	0.992	0.989	0.986	0.986	0.984	0.985	0.983	0.986	0.982	0.985	0.983	0.984	0.984	0.987	0.985	0.989	0.991	0.991	0.997	0.991
Carnmoney	110kV	0.996	0.993	0.998	0.993	0.992	0.989	0.987	0.986	0.984	0.986	0.984	0.986	0.982	0.985	0.983	0.985	0.984	0.987	0.986	0.989	0.991	0.992	0.997	0.991
Castlereagh	110kV	0.999	0.995	1.001	0.994	0.995	0.991	0.990	0.988	0.987	0.988	0.985	0.987	0.984	0.987	0.985	0.986	0.987	0.989	0.989	0.991	0.995	0.993	1.000	0.993
Castlereagh	110kV	0.999	0.995	1.001	0.994	0.995	0.991	0.990	0.988	0.987	0.988	0.985	0.987	0.984	0.987	0.985	0.986	0.987	0.989	0.989	0.991	0.995	0.993	1.000	0.993
Castlereagh	275kV	0.995	0.992	0.997	0.992	0.992	0.989	0.987	0.986	0.984	0.985	0.983	0.985	0.982	0.985	0.983	0.985	0.984	0.987	0.985	0.989	0.991	0.991	0.996	0.990
Belast Central	110kV	0.999	0.995	1.001	0.995	0.996	0.992	0.991	0.989	0.987	0.988	0.985	0.987	0.984	0.987	0.986	0.986	0.988	0.990	0.989	0.991	0.995	0.994	1.000	0.993
Belast Central	110kV	0.999	0.995	1.001	0.995	0.996	0.992	0.991	0.989	0.987	0.988	0.985	0.987	0.984	0.987	0.986	0.986	0.988	0.990	0.989	0.991	0.995	0.994	1.000	0.993
Coleraine	110kV	1.000	0.998	1.002	0.997	0.997	0.994	0.997	0.994	0.984	0.989	0.981	0.989	0.977	0.986	0.981	0.988	0.984	0.991	0.987	0.992	0.993	0.995	0.999	0.993
Coolkerragh	110kV	0.984	0.988	0.986	0.987	0.984	0.986	0.986	0.987	0.970	0.981	0.967	0.982	0.965	0.981	0.970	0.983	0.971	0.985	0.973	0.985	0.978	0.987	0.983	0.985
Coolkerragh	275kV	0.987	0.989	0.989	0.989	0.986	0.987	0.986	0.987	0.974	0.982	0.971	0.983	0.969	0.982	0.973	0.983	0.974	0.986	0.976	0.986	0.981	0.988	0.986	0.986
Creagh	110kV	0.999	0.995	1.001	0.995	0.996	0.992	0.991	0.989	0.986	0.988	0.981	0.985	0.980	0.984	0.982	0.984	0.984	0.987	0.985	0.988	0.990	0.991	0.996	0.990
Creagh	110kV	0.999	0.995	1.001	0.995	0.995	0.991	0.991	0.989	0.986	0.988	0.981	0.985	0.980	0.984	0.982	0.984	0.984	0.987	0.985	0.988	0.990	0.991	0.996	0.990
Creagh	110kV	0.999	0.995	1.001	0.995	0.996	0.992	0.991	0.989	0.987	0.988	0.981	0.985	0.980	0.984	0.982	0.984	0.984	0.987	0.985	0.988	0.990	0.991	0.996	0.990
Cregagh	110kV	0.999	0.995	1.001	0.995	0.996	0.991	0.991	0.989	0.987	0.988	0.985	0.987	0.984	0.987	0.985	0.986	0.988	0.989	0.989	0.991	0.995	0.994	1.000	0.993
Cregagh	110kV	0.999	0.995	1.001	0.995	0.996	0.991	0.991	0.989	0.987	0.988	0.985	0.987	0.984	0.987	0.985	0.986	0.988	0.989	0.989	0.991	0.995	0.994	1.000	0.993
Donegal	110kV	0.996	0.993	0.999	0.992	0.993	0.989	0.987	0.986	0.984	0.986	0.984	0.986	0.982	0.985	0.984	0.985	0.985	0.988	0.987	0.989	0.993	0.992	0.998	0.991
Donegal	110kV	0.996	0.993	0.999	0.992	0.993	0.989	0.987	0.986	0.984	0.986	0.984	0.986	0.982	0.985	0.984	0.985	0.985	0.988	0.987	0.989	0.992	0.992	0.998	0.991
Donegal	110kV	0.996	0.993	0.999	0.993	0.993	0.989	0.987	0.986	0.984	0.986	0.984	0.986	0.982	0.985	0.984	0.985	0.985	0.988	0.987	0.989	0.993	0.992	0.998	0.991
Donegal	110kV	0.996	0.993	0.999	0.993	0.993	0.989	0.987	0.986	0.984	0.986	0.984	0.986	0.982	0.985	0.984	0.985	0.985	0.988	0.987	0.989	0.993	0.992	0.998	0.991
Drumnakelly	110kV	1.000	0.997	1.002	0.996	0.997	0.993	0.993	0.991	0.990	0.990	0.987	0.989	0.986	0.989	0.988	0.989	0.989	0.991	0.990	0.992	0.995	0.995	1.000	0.994
Dungannon	110kV	1.007	1.001	1.008	1.001	1.003	0.997	1.000	0.995	0.993	0.993	0.984	0.987	0.982	0.987	0.984	0.987	0.986	0.989	0.987	0.990	0.993	0.993	0.998	0.992
Eden	110kV	0.992	0.990	0.995	0.990	0.989	0.987	0.983	0.983	0.980	0.983	0.981	0.984	0.979	0.983	0.980	0.982	0.981	0.985	0.982	0.986	0.988	0.989	0.994	0.988
Eden	110kV	0.992	0.990	0.995	0.990	0.989	0.987	0.983	0.983	0.981	0.983	0.981	0.984	0.979	0.983	0.980	0.983	0.981	0.985	0.982	0.987	0.988	0.989	0.994	0.988
Enniskillen	110kV	1.013	1.004	1.013	1.003	1.007	0.999	1.006	0.998	0.994	0.992	0.985	0.989	0.983	0.987	0.987	0.989	0.990	0.992	0.992	0.992	0.999	0.996	1.005	0.995
Derrylin	110kV	1.014	1.005	1.015	1.003	1.008	1.000	1.008	0.998	0.995	0.993	0.986	0.989	0.983	0.987	0.988	0.989	0.991	0.992	0.993	0.993	1.000	0.997	1.006	0.996
Finaghy	110kV	0.996	0.992	0.998	0.992	0.993	0.989	0.987	0.986	0.984	0.986	0.983	0.985	0.982	0.985	0.983	0.984	0.985	0.987	0.986	0.989	0.992	0.992	0.997	0.991
Finaghy	110kV	0.996	0.992	0.998	0.992	0.993	0.989	0.987	0.986	0.984	0.986	0.983	0.985	0.982	0.985	0.983	0.984	0.985	0.987	0.986	0.989	0.992	0.992	0.997	0.991
Glengormley	110kV	0.994	0.992	0.997	0.991	0.991	0.988	0.986	0.985	0.983	0.985	0.980	0.984	0.979	0.983	0.980	0.983	0.982	0.986	0.983	0.987	0.989	0.990	0.995	0.989
Glengormley	110kV	0.992	0.990	0.994	0.990	0.989	0.987	0.984	0.983	0.981	0.983	0.978	0.982	0.977	0.981	0.978	0.981	0.980	0.984	0.981	0.985	0.986	0.988	0.993	0.988
Hannahstown	110kV	0.996	0.992	0.998	0.992	0.992	0.989	0.987	0.986	0.984	0.985	0.983	0.985	0.982	0.985	0.983	0.984	0.985	0.987	0.986	0.989	0.992	0.991	0.997	0.991
Hannahstown	275kV	0.994	0.991	0.996	0.991	0.991	0.988	0.986	0.985	0.983	0.985	0.982	0.984	0.980	0.984	0.982	0.984	0.983	0.986	0.984	0.988	0.990	0.990	0.995	0.989
Kells	110kV	0.993	0.991	0.995	0.990	0.990	0.987	0.985	0.984	0.982	0.984	0.979	0.983	0.978	0.983	0.979	0.982	0.981	0.985	0.982	0.986	0.988	0.989	0.993	0.988
Kells	275kV	0.991	0.989	0.993	0.989	0.989	0.986	0.984	0.984	0.980	0.983	0.979	0.983	0.977	0.983	0.979	0.982	0.980	0.985	0.981	0.986	0.986	0.988	0.992	0.987
Kilroot	275kV	0.990	0.989	0.993	0.988	0.988	0.986	0.983	0.983	0.980	0.983	0.979	0.983	0.977	0.983	0.979	0.983	0.980	0.985	0.981	0.985	0.986	0.987	0.991	0.987
Knock	110kV	0.999	0.995	1.001	0.995	0.996	0.992	0.991	0.989	0.987	0.988	0.986	0.987	0.984	0.987	0.986	0.986	0.988	0.990	0.989	0.991	0.995	0.994	1.001	0.993
Knock	110kV	0.999	0.995	1.001	0.995	0.996	0.992	0.991	0.989	0.987	0.988	0.986	0.987	0.984	0.987	0.986	0.986	0.988	0.990	0.989	0.991	0.995	0.994	1.001	0.993

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Larne	110kV	0.991	0.989	0.994	0.989	0.988	0.986	0.982	0.982	0.979	0.982	0.979	0.983	0.977	0.982	0.978	0.981	0.979	0.984	0.980	0.985	0.986	0.988	0.992	0.987
Larne	110kV	0.991	0.989	0.994	0.989	0.988	0.986	0.982	0.982	0.979	0.982	0.979	0.983	0.977	0.982	0.978	0.981	0.979	0.984	0.980	0.985	0.986	0.988	0.992	0.987
Limavady	110kV	0.994	0.994	0.996	0.993	0.993	0.991	0.993	0.991	0.979	0.985	0.976	0.986	0.973	0.984	0.977	0.985	0.980	0.988	0.982	0.989	0.988	0.992	0.993	0.990
Lisburn	110kV	0.999	0.995	1.001	0.995	0.995	0.991	0.990	0.988	0.987	0.988	0.986	0.988	0.985	0.987	0.986	0.987	0.988	0.990	0.989	0.991	0.995	0.994	1.000	0.993
Lisburn	110kV	0.998	0.995	1.000	0.994	0.995	0.991	0.990	0.988	0.987	0.988	0.986	0.987	0.984	0.987	0.986	0.987	0.987	0.989	0.989	0.991	0.995	0.994	1.000	0.993
Lisaghmore	110kV	0.985	0.990	0.987	0.989	0.985	0.987	0.987	0.988	0.971	0.982	0.968	0.983	0.966	0.982	0.970	0.984	0.973	0.986	0.974	0.987	0.979	0.988	0.984	0.986
Lisaghmore	110kV	0.985	0.990	0.987	0.989	0.985	0.987	0.987	0.988	0.971	0.982	0.968	0.983	0.966	0.982	0.970	0.984	0.973	0.986	0.974	0.987	0.979	0.988	0.984	0.986
Loguestown	110kV	1.001	0.999	1.003	0.998	0.999	0.995	0.998	0.994	0.985	0.990	0.982	0.990	0.978	0.987	0.982	0.988	0.985	0.992	0.988	0.993	0.994	0.996	1.000	0.994
Loguestown	110kV	1.001	0.999	1.003	0.998	0.999	0.995	0.998	0.994	0.985	0.990	0.982	0.990	0.978	0.987	0.982	0.988	0.985	0.992	0.988	0.993	0.994	0.996	1.000	0.994
Magherafelt	275kV	0.991	0.990	0.994	0.990	0.989	0.988	0.986	0.985	0.981	0.984	0.978	0.983	0.977	0.983	0.978	0.983	0.980	0.985	0.981	0.986	0.986	0.989	0.992	0.988
Moyle	275kV	0.990	0.988	0.992	0.987	0.987	0.984	0.981	0.981	0.978	0.981	0.977	0.981	0.976	0.981	0.977	0.980	0.978	0.983	0.979	0.984	0.985	0.986	0.991	0.985
Newtownards	110kV	1.001	0.997	1.004	0.997	0.998	0.993	0.993	0.990	0.989	0.989	0.987	0.989	0.986	0.988	0.987	0.988	0.990	0.991	0.991	0.993	0.997	0.995	1.003	0.995
Newtownards	110kV	1.001	0.997	1.004	0.997	0.998	0.993	0.993	0.990	0.989	0.989	0.987	0.989	0.986	0.988	0.987	0.988	0.990	0.991	0.991	0.993	0.997	0.995	1.003	0.995
Newry	110kV	1.006	1.001	1.007	1.001	1.002	0.998	0.998	0.995	0.995	0.994	0.993	0.994	0.992	0.993	0.994	0.993	0.995	0.995	0.997	0.997	1.002	1.000	1.007	0.999
Newry	110kV	1.006	1.001	1.007	1.001	1.002	0.998	0.998	0.995	0.995	0.994	0.993	0.993	0.991	0.993	0.993	0.993	0.995	0.995	0.997	0.997	1.002	1.000	1.007	0.999
Norfil	110kV	0.994	0.992	0.996	0.991	0.991	0.988	0.986	0.985	0.983	0.985	0.980	0.984	0.979	0.983	0.980	0.983	0.982	0.986	0.983	0.987	0.989	0.989	0.995	0.989
Norfil	110kV	0.994	0.992	0.996	0.991	0.991	0.988	0.986	0.985	0.983	0.985	0.980	0.984	0.979	0.983	0.980	0.983	0.982	0.986	0.983	0.987	0.989	0.989	0.995	0.989
Omagh	110kV	1.004	0.999	1.004	0.998	0.999	0.994	0.999	0.993	0.987	0.989	0.980	0.985	0.978	0.985	0.981	0.986	0.984	0.989	0.985	0.989	0.991	0.992	0.996	0.990
Rathgael	110kV	1.003	0.998	1.005	0.998	0.999	0.994	0.994	0.991	0.990	0.990	0.989	0.989	0.987	0.989	0.989	0.989	0.991	0.992	0.993	0.994	0.999	0.997	1.005	0.996
Rathgael	110kV	1.003	0.998	1.005	0.998	0.999	0.994	0.994	0.991	0.990	0.990	0.989	0.989	0.987	0.989	0.989	0.989	0.991	0.992	0.993	0.994	0.999	0.997	1.005	0.996
Rosebank	110kV	0.999	0.995	1.001	0.994	0.995	0.991	0.990	0.988	0.987	0.988	0.985	0.987	0.984	0.987	0.985	0.986	0.987	0.989	0.989	0.991	0.995	0.993	1.000	0.993
Rosebank	110kV	0.999	0.995	1.001	0.994	0.995	0.991	0.990	0.988	0.987	0.988	0.985	0.987	0.984	0.987	0.985	0.986	0.987	0.989	0.989	0.991	0.995	0.993	1.000	0.993
Strabane	110kV	0.989	0.991	0.991	0.990	0.988	0.988	0.990	0.989	0.974	0.983	0.970	0.983	0.968	0.982	0.972	0.983	0.975	0.986	0.976	0.986	0.981	0.988	0.987	0.986
Tandragee	110kV	0.998	0.995	1.000	0.995	0.995	0.992	0.992	0.990	0.988	0.989	0.987	0.989	0.985	0.989	0.987	0.988	0.988	0.990	0.990	0.992	0.995	0.994	0.999	0.994
Tandragee	110kV	0.998	0.995	1.000	0.995	0.995	0.992	0.992	0.990	0.988	0.989	0.987	0.989	0.985	0.989	0.987	0.988	0.988	0.990	0.990	0.992	0.995	0.994	0.999	0.994
Tandragee	275kV	0.995	0.993	0.997	0.993	0.993	0.990	0.989	0.988	0.985	0.987	0.985	0.988	0.984	0.988	0.986	0.988	0.987	0.990	0.988	0.991	0.993	0.993	0.997	0.992
Coal Island	110kV											0.981	0.985	0.980	0.985	0.982	0.985	0.983	0.988	0.985	0.989	0.990	0.991	0.995	0.990
Coal Island	275kV											0.977	0.983	0.975	0.982	0.977	0.982	0.979	0.985	0.980	0.986	0.985	0.988	0.991	0.987
Warringstown	110kV	1.001	0.997	1.002	0.997	0.997	0.994	0.994	0.992	0.990	0.991	0.988	0.990	0.987	0.990	0.989	0.990	0.990	0.992	0.992	0.993	0.997	0.996	1.001	0.995
Warringstown	110kV	1.001	0.997	1.002	0.997	0.997	0.994	0.994	0.992	0.990	0.991	0.988	0.990	0.987	0.990	0.989	0.990	0.990	0.992	0.992	0.993	0.997	0.996	1.001	0.995
West Belfast Central	110kV	0.997	0.993	0.999	0.993	0.994	0.990	0.988	0.987	0.985	0.986	0.984	0.986	0.983	0.985	0.984	0.985	0.986	0.988	0.987	0.990	0.993	0.993	0.999	0.992
West Belfast Central	110kV	0.997	0.993	0.999	0.993	0.994	0.990	0.988	0.986	0.985	0.986	0.984	0.986	0.983	0.985	0.984	0.985	0.986	0.988	0.987	0.990	0.993	0.992	0.998	0.992

2007 Compression Factor TLAF																									
		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
Unit	kV	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Aghada (ESB)	220kV	1.017	1.024	1.017	1.024	1.020	1.022	1.020	1.022	1.020	1.022	1.020	1.016	1.020	1.016	1.020	1.016	1.019	1.021	1.019	1.021	1.024	1.025	1.022	1.026
Aghada PCP (ESB)	110kV	1.018	1.025	1.018	1.025	1.020	1.022	1.020	1.022	1.020	1.022	1.020	1.017	1.020	1.017	1.020	1.017	1.019	1.022	1.019	1.022	1.025	1.026	1.023	1.026
Ardnacrusha (ESB)	110kV	1.002	1.004	1.002	1.004	1.012	1.009	1.012	1.009	1.012	1.009	1.014	1.006	1.014	1.006	1.014	1.006	1.013	1.011	1.013	1.011	1.010	1.012	1.009	1.010
Ballywater (Ballywater Windfarms Ltd	110kV	1.020	1.017	1.020	1.017	1.013	1.010	1.013	1.010	1.013	1.010	1.012	1.035	1.012	1.009	1.012	1.009	1.014	1.009	1.014	1.009	1.023	1.022	1.023	1.022
Booltiagh (Booltiagh Windfarm Ltd.)	110kV	1.002	1.003	1.002	1.003	1.009	1.005	1.009	1.005	1.009	1.005	1.010	1.001	1.010	1.001	1.010	1.001	1.010	1.007	1.010	1.007	1.008	1.009	1.007	1.009
Bindoo Windfarm Ltd.	110kV	1.005	0.989	1.005	0.989	0.995	0.994	0.995	0.994	0.995	0.994	0.994	0.994	0.994	0.994	0.994	0.994	0.994	0.987	0.994	0.987	1.001	0.993	1.002	0.996
Coomagearlahy (SWS Kilgarvan Wind	110kV	1.009	1.016	1.009	1.016	1.014	1.013	1.014	1.013	1.014	1.013	1.013	1.006	1.013	1.006	1.013	1.006	1.010	1.008	1.010	1.008	1.009	1.008	1.008	1.009
Barnesmore Wind Farm (Golagh)	110kV																					0.992	0.983	0.990	0.981
Coomagearlahy	110kV																					1.009	1.008	1.008	1.009
Derrybrien	110kV	0.993	0.991	0.993	0.991	0.997	0.991	0.997	0.991	0.997	0.991	0.998	0.989	0.998	0.989	0.998	0.989	1.000	0.993	1.000	0.993	0.998	0.994	0.998	0.995
Dublin Bay Power	220kV	0.990	0.996	0.990	0.996	0.986	0.993	0.986	0.993	0.986	0.993	0.988	0.997	0.988	0.997	0.988	0.997	0.987	0.994	0.987	0.994	0.991	1.002	0.992	1.000
Edenderry (Edenderry Power Ltd.)	110kV	0.974	0.968	0.974	0.968	0.969	0.965	0.969	0.965	0.969	0.965	0.971	0.967	0.971	0.967	0.971	0.967	0.989	0.985	0.989	0.985	0.973	0.968	0.977	0.969
Erne (ESB)	110kV	1.002	0.979	1.002	0.979	0.999	0.989	0.999	0.989	0.999	0.989	0.993	0.985	0.993	0.985	0.993	0.985	0.990	0.980	0.990	0.980	0.991	0.987	0.988	0.982
Erne (ESB)	110kV	1.004	0.981	1.004	0.981	1.000	0.990	1.000	0.990	1.000	0.990	0.993	0.985	0.993	0.985	0.993	0.985	0.991	0.981	0.991	0.981	0.992	0.987	0.990	0.983
Glanlee Wind Farm	110kV											1.012	1.006	1.012	1.006	1.012	1.006	1.010	1.008	1.010	1.008	1.009	1.008	1.008	1.009
Great Island (ESB)	110kV	1.018	1.020	1.018	1.020	1.015	1.016	1.015	1.016	1.015	1.016	1.015	1.014	1.015	1.014	1.015	1.014	1.015	1.015	1.015	1.015	1.022	1.024	1.021	1.023
Great Island (ESB)	220kV	1.013	1.016	1.013	1.016	1.011	1.012	1.011	1.012	1.011	1.012	1.011	1.011	1.011	1.011	1.011	1.011	1.011	1.012	1.011	1.012	1.016	1.020	1.016	1.019
Huntstown 1 (Huntstown Power Ltd.)	220kV	0.990	0.996	0.990	0.996	0.986	0.992	0.986	0.992	0.986	0.992	0.988	0.996	0.988	0.996	0.988	0.996	0.985	0.993	0.985	0.993	0.989	1.001	0.989	0.999
Huntstown 2 (Huntstown Power Ltd.)	220kV											0.987	0.996	0.987	0.996	0.987	0.996	0.984	0.992	0.984	0.992	0.988	1.000	0.988	0.998
Kingsmountain (Brickmount Ltd.)	110kV	1.029	1.003	1.029	1.003	1.023	1.006	1.023	1.006	1.023	1.006	1.006	0.996	1.006	0.996	1.006	0.996	1.009	0.996	1.009	0.996	1.010	1.002	1.009	1.003
Lee (ESB)	110kV	1.016	1.023	1.016	1.023	1.021	1.021	1.021	1.021	1.021	1.021	1.020	1.014	1.020	1.014	1.020	1.014	1.019	1.018	1.019	1.018	1.020	1.022	1.019	1.022
Lee (ESB)	110kV	1.020	1.028	1.020	1.028	1.024	1.025	1.024	1.025	1.024	1.025	1.025	1.017	1.025	1.017	1.025	1.017	1.024	1.023	1.024	1.023	1.025	1.027	1.023	1.027
Liffey (ESB)	110kV	1.008	1.009	1.008	1.009	1.007	1.004	1.007	1.004	1.007	1.004	1.010	1.005	1.010	1.005	1.010	1.005	1.009	1.005	1.009	1.005	1.013	1.015	1.013	1.014
Lough Ree Power (ESB)	110kV	0.996	0.986	0.996	0.986	0.994	0.984	0.994	0.984	0.994	0.984	0.993	0.983	0.993	0.983	0.993	0.983	1.003	0.992	1.003	0.992	0.998	0.987	0.996	0.987
Marina (ESB)	110kV	1.025	1.031	1.025	1.031	1.027	1.027	1.027	1.027	1.027	1.027	1.028	1.021	1.028	1.021	1.028	1.021	1.027	1.026	1.027	1.026	1.030	1.031	1.029	1.032
Meentycat (Meentycat Ltd.)	110kV	1.005	0.971	1.005	0.971	0.994	0.976	0.994	0.976	0.994	0.976	0.987	0.970	0.987	0.970	0.987	0.970	0.986	0.967	0.986	0.967	0.991	0.978	0.990	0.977
Moneypoint (ESB)	380kV	0.978	0.983	0.978	0.983	0.984	0.989	0.840	0.989	0.984	0.989	0.986	0.991	0.986	0.991	0.986	0.991	0.983	0.988	0.983	0.988	0.982	0.988	0.982	0.986
North Wall (ESB)	220kV	0.991	0.997	0.991	0.997	0.987	0.993	0.987	0.993	0.987	0.993	0.989	0.997	0.989	0.997	0.989	0.997	0.985	0.993	0.985	0.993	0.989	1.001	0.989	0.999
North Wall (ESB)	220kV	0.991	0.997	0.991	0.997	0.987	0.993	0.987	0.993	0.987	0.993	0.989	0.997	0.989	0.997	0.989	0.997	0.985	0.993	0.985	0.993	0.990	1.001	0.990	1.000
Poolbeg (ESB)	220kV	0.991	0.997	0.991	0.997	0.988	0.994	0.988	0.994	0.988	0.994	0.989	0.998	0.989	0.998	0.989	0.998	0.988	0.995	0.988	0.995	0.993	1.003	0.993	1.001
Poolbeg (ESB)	220kV	0.990	0.995	0.990	0.995	0.986	0.992	0.986	0.992	0.986	0.992	0.988	0.997	0.988	0.997	0.988	0.997	0.986	0.993	0.986	0.993	0.991	1.002	0.991	1.000
Rhode PCP (ESB)	110kV	0.998	1.001	0.998	1.001	0.995	0.998	0.995	0.998	0.995	0.998	0.997	1.001	0.997	1.001	0.997	1.001	0.996	0.998	0.996	0.998	1.000	1.006	1.000	1.005
Seal Rock (Aughinish Alumina)	110kV	0.984	0.989	0.984	0.989	0.996	0.994	0.996	0.994	0.996	0.994	0.994	0.988	0.994	0.988	0.994	0.988	0.995	0.993	0.995	0.993	0.992	0.991	0.991	0.991
Tarbert (ESB)	110kV	0.985	0.995	0.985	0.995	0.999	1.000	0.999	1.000	0.999	1.000	0.998	0.996	0.998	0.996	0.998	0.996	0.998	1.000	0.998	1.000	0.994	0.996	0.994	0.997
Tarbert (ESB)	220kV	0.988	0.997	0.988	0.997	1.000	1.001	1.000	1.001	1.000	1.001	0.999	0.998	0.999	0.998	0.999	0.998	1.000	1.001	1.000	1.001	0.996	0.999	0.996	0.999

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Tawnaghmore PCP (ESB)	110kV	1.044	1.014	1.044	1.014	1.038	1.014	1.038	1.014	1.038	1.014	1.024	1.004	1.024	1.004	1.024	1.004	1.029	1.007	1.029	1.007	1.028	1.016	1.027	1.017
Turlough Hill (ESB)	220kV	0.990	1.000	0.990	1.000	0.988	0.996	0.988	0.996	0.988	0.996	0.989	0.999	0.989	0.999	0.989	0.999	0.988	0.996	0.988	0.996	0.991	1.004	0.992	0.999
Tynagh CCGT	220kV	0.975	0.976	0.975	0.976	0.978	0.981	0.978	0.981	0.978	0.981	0.979	0.982	0.979	0.982	0.979	0.982	0.981	0.984	0.984	0.984	0.977	0.982	0.978	0.982
West Offaly Power (ESB)	110kV	0.994	0.991	0.994	0.991	0.994	0.989	0.994	0.989	0.994	0.989	0.996	0.990	0.996	0.990	0.996	0.990	0.998	0.993	0.998	0.993	0.996	0.994	0.998	0.996
A&L Goodbody (Bord Gais)		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000				
A&L Goodbody (Marren Engineer	220kV	0.991	0.997	0.991	0.997	0.988	0.994	0.988	0.994	0.988	0.994	0.989	0.998	0.989	0.998	0.989	0.998	0.985	0.993	0.985	0.993				
Altagowlan (Moneeenatieve Wind	110kV	0.999	0.984	0.999	0.984	0.996	0.990	0.996	0.990	0.996	0.990	0.994	0.992	0.994	0.992	0.994	0.992	0.996	0.991	0.996	0.991				
Arklow Banks (Arklow Energy Lt	110kV	0.998	1.003	0.998	1.003	0.994	0.999	0.994	0.999	0.994	0.999	0.995	1.001	0.995	1.001	0.995	1.001	0.994	0.999	0.994	0.999	1.000	1.008	1.001	1.007
Arthurstown Landfill Phase 2 (Iri	110kV	0.996	1.000	0.996	1.000	0.992	0.997	0.992	0.997	0.992	0.997	0.993	1.000	0.993	1.000	0.993	1.000	0.995	0.998	0.995	0.998	0.998	1.004	0.997	0.999
Arthurstown Landfill Phase 3 (Iri	110kV	0.996	1.000	0.996	1.000	0.992	0.997	0.992	0.997	0.992	0.997	0.993	1.000	0.993	1.000	0.993	1.000	0.995	0.998	0.995	0.998	0.998	1.004	0.997	0.999
Ballineen (CM Power Ltd)	110kV	1.029	1.033	1.029	1.033	1.032	1.029	1.032	1.029	1.032	1.029	1.028	1.018	1.028	1.018	1.028	1.018	1.029	1.024	1.029	1.024				
Ballinlough I (Jaroma Windfarm L	110kV	1.025	1.019	1.025	1.019	1.026	1.015	1.026	1.015	1.026	1.015	1.026	1.012	1.026	1.012	1.026	1.012	1.028	1.016	1.028	1.016				
Ballinveny I (North Tipperary Wind	110kV	1.025	1.019	1.025	1.019	1.026	1.015	1.026	1.015	1.026	1.015	1.026	1.012	1.026	1.012	1.026	1.012	1.028	1.016	1.028	1.016				
Ballyragget Power (Glanbia Plc.)	110kV	1.024	1.025	1.024	1.025	1.018	1.019	1.018	1.019	1.018	1.019	1.018	1.018	1.018	1.018	1.018	1.018	1.019	1.019	1.019	1.019				
Beal Hill (Port Finch Ltd)	110kV	0.996	1.004	0.996	1.004	1.007	1.006	1.007	1.006	1.007	1.006	1.003	0.999	1.003	0.999	1.003	0.999	1.002	1.002	1.002	1.002				
Beam Hill (Beam Wind Ltd.)	110kV	1.007	0.968	1.007	0.968	0.994	0.971	0.994	0.971	0.994	0.971	0.985	0.964	0.985	0.964	0.985	0.964	0.986	0.962	0.986	0.962	0.991	0.974	0.990	0.974
Carnsore (Hibernian Wind Power	110kV	1.025	1.021	1.025	1.021	1.018	1.014	1.018	1.014	1.018	1.014	1.017	1.011	1.017	1.011	1.017	1.011	1.019	1.013	1.019	1.013	1.028	1.024	1.028	1.025
Culliagh (Dedondo Ltd.)	110kV	1.010	0.973	1.010	0.973	0.998	0.978	0.998	0.978	0.998	0.978	0.991	0.971	0.991	0.971	0.991	0.971	0.990	0.968	0.990	0.968	0.994	0.980	0.993	0.980
Gartnaneane (Gartnaneane Ltd.)	110kV	0.996	0.992	0.996	0.992	0.992	0.999	0.992	0.999	0.992	0.999	0.992	1.001	0.992	1.001	0.992	1.001	0.992	0.991	0.992	0.991	0.999	0.995	1.000	0.997
Moanmore (Kilrush Energy Ltd.)	110kV	1.003	1.005	1.003	1.005	1.011	1.007	1.011	1.007	1.011	1.007	1.011	1.002	1.011	1.002	1.011	1.002	1.011	1.008	1.011	1.008	1.009	1.011	1.008	1.011
Raheen Barr (Matrix Energy Partn	110kV	1.036	1.013	1.036	1.013	1.033	1.013	1.033	1.013	1.033	1.013	1.025	1.005	1.025	1.005	1.025	1.005	1.032	1.011	1.032	1.011	1.029	1.023	1.028	1.026
Richfield (Richfield Windfarm (RO	110kV	1.025	1.021	1.025	1.021	1.018	1.014	1.018	1.014	1.018	1.014	1.017	1.019	1.017	1.011	1.017	1.011	1.019	1.013	1.019	1.013	1.028	1.024	1.028	1.025
Sorne Hill (Sorne Wind Ltd.)	110kV	1.007	0.968	1.007	0.968	0.994	0.971	0.994	0.971	0.994	0.971	0.985	0.964	0.985	0.964	0.985	0.964	0.986	0.962	0.986	0.962	0.991	0.974	0.990	0.974
Taurbeg (Taurbeg Ltd.)	110kV	1.020	1.017	1.020	1.017	1.024	1.017	1.024	1.017	1.024	1.017	1.023	1.010	1.023	1.010	1.023	1.010	1.025	1.016	1.025	1.016	1.027	1.020	1.024	1.019
Tursillagh 2	110kV	1.007	1.014	1.007	1.014	1.012	1.010	1.012	1.010	1.012	1.010	1.009	1.003	1.009	1.003	1.009	1.003	1.008	1.007	1.008	1.007	1.005	1.006	1.004	1.007
ANTR1A	110kV	0.989	0.983	0.990	0.982	0.989	0.993	0.986	0.995	0.987	0.987	0.993	0.996	0.989	0.998	0.984	0.995	0.980	0.984	0.994	0.987	0.994	0.985	0.996	0.988
ANTR1B	110kV	0.989	0.983	0.990	0.982	0.989	0.993	0.986	0.995	0.987	0.987	0.993	0.996	0.989	0.998	0.984	0.995	0.980	0.984	0.994	0.987	0.994	0.985	0.996	0.988
BAFD1-	110kV	0.982	0.981	0.983	0.980	0.983	0.991	0.980	0.994	0.982	0.982	0.986	0.995	0.983	0.997	0.977	0.995	0.973	0.982	0.987	0.985	0.988	0.983	0.989	0.985
BAFD2-	275kV	0.985	0.982	0.986	0.981	0.985	0.992	0.983	0.994	0.984	0.984	0.989	0.995	0.985	0.997	0.980	0.995	0.976	0.982	0.990	0.985	0.990	0.983	0.991	0.986
BAME1A	110kV	0.993	0.985	0.994	0.984	0.992	0.995	0.989	0.997	0.990	0.990	0.996	0.998	0.992	0.999	0.987	0.997	0.984	0.986	0.998	0.990	0.998	0.988	0.999	0.990
BAME1B	110kV	0.993	0.985	0.994	0.984	0.992	0.995	0.989	0.997	0.990	0.990	0.996	0.998	0.992	0.999	0.987	0.997	0.984	0.986	0.998	0.990	0.998	0.988	0.999	0.990
BANB1A	110kV	0.999	0.992	0.999	0.991	0.997	0.998	0.995	1.000	0.996	0.996	0.999	1.001	0.997	1.002	0.993	1.000	0.991	0.991	1.000	0.994	1.000	0.993	1.001	0.995
BANB1B	110kV	0.999	0.992	0.999	0.991	0.997	0.998	0.995	1.000	0.996	0.996	0.999	1.001	0.997	1.002	0.993	1.000	0.991	0.991	1.000	0.994	1.000	0.993	1.001	0.995
BAVA1-	110kV	0.986	0.983	0.987	0.981	0.986	0.993	0.984	0.995	0.985	0.985	0.990	0.996	0.986	0.998	0.981	0.996	0.977	0.983	0.991	0.986	0.991	0.984	0.993	0.987
BNCH1A	110kV	0.998	0.990	0.999	0.989	0.997	0.999	0.994	1.001	0.995	0.995	1.000	1.002	0.996	1.003	0.992	1.001	0.989	0.990	1.002	0.994	1.002	0.992	1.004	0.995
BNCH1B	110kV	0.998	0.990	0.999	0.989	0.997	0.999	0.994	1.001	0.995	0.995	1.000	1.002	0.996	1.003	0.992	1.001	0.989	0.990	1.002	0.994	1.002	0.992	1.004	0.995

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
CACO2A	275kV	0.986	0.980	0.987	0.978	0.983	0.984	0.980	0.986	0.981	0.981	0.985	0.987	0.983	0.989	0.979	0.987	0.978	0.979	0.995	0.988	0.987	0.980	0.988	0.983
CACO2B	275kV	0.986	0.980	0.987	0.978	0.983	0.984	0.980	0.986	0.981	0.981	0.985	0.987	0.983	0.989	0.979	0.987	0.978	0.979	0.995	0.988	0.987	0.980	0.988	0.983
CARN1A	110kV	0.990	0.986	0.991	0.985	0.990	0.997	0.987	0.999	0.989	0.989	0.993	1.000	0.990	1.002	0.984	1.000	0.980	0.986	0.995	0.990	0.996	0.988	0.997	0.991
CARN1B	110kV	0.990	0.986	0.991	0.985	0.990	0.997	0.987	1.000	0.988	0.988	0.993	1.000	0.990	1.002	0.984	1.000	0.980	0.987	0.994	0.990	0.996	0.988	0.997	0.991
CAST1A	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.995	0.999	0.992	1.000	0.987	0.998	0.984	0.987	0.997	0.990	0.997	0.988	0.998	0.991
CAST1B	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.995	0.999	0.992	1.000	0.987	0.998	0.984	0.987	0.997	0.990	0.997	0.988	0.998	0.991
CAST2-	275kV	0.991	0.986	0.992	0.985	0.991	0.994	0.988	0.996	0.989	0.989	0.994	0.998	0.990	0.999	0.986	0.997	0.983	0.986	0.995	0.989	0.995	0.987	0.996	0.989
CENT1A	110kV	0.994	0.987	0.995	0.987	0.993	0.996	0.991	0.998	0.991	0.991	0.996	0.999	0.993	1.001	0.988	0.998	0.985	0.988	0.998	0.991	0.998	0.989	0.999	0.991
CENT1B	110kV	0.994	0.987	0.995	0.987	0.993	0.996	0.991	0.998	0.991	0.991	0.996	0.999	0.993	1.001	0.988	0.998	0.985	0.988	0.998	0.991	0.998	0.989	0.999	0.991
COLE1-	110kV	1.002	0.988	1.002	0.987	0.997	0.994	0.993	0.995	0.994	0.994	0.998	0.995	0.995	0.996	0.992	0.994	0.991	0.987	1.009	0.995	1.002	0.988	1.002	0.991
COOL1-	110kV	0.987	0.979	0.988	0.978	0.983	0.982	0.980	0.984	0.981	0.981	0.984	0.985	0.982	0.986	0.979	0.985	0.979	0.978	0.996	0.988	0.987	0.979	0.988	0.981
COOLKEE	275kV	0.986	0.979	0.986	0.978	0.983	0.984	0.980	0.986	0.980	0.980	0.985	0.987	0.983	0.989	0.979	0.987	0.978	0.979	0.995	0.988	0.987	0.980	0.988	0.982
CREAGH	110kV	0.982	0.979	0.984	0.978	0.983	0.990	0.980	0.992	0.982	0.982	0.988	0.994	0.984	0.996	0.978	0.993	0.974	0.981	0.990	0.985	0.990	0.983	0.992	0.985
CREC1A	110kV	0.983	0.979	0.984	0.978	0.983	0.990	0.980	0.992	0.982	0.982	0.988	0.994	0.984	0.996	0.978	0.993	0.974	0.981	0.990	0.985	0.990	0.983	0.992	0.985
CREC1B	110kV	0.982	0.979	0.984	0.978	0.982	0.990	0.980	0.992	0.982	0.982	0.988	0.994	0.983	0.996	0.978	0.993	0.974	0.981	0.990	0.985	0.990	0.983	0.992	0.985
CREG1A	110kV	0.994	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.000	0.988	0.998	0.985	0.987	0.998	0.991	0.998	0.989	0.999	0.991
CREG1B	110kV	0.994	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.000	0.988	0.998	0.985	0.987	0.998	0.991	0.998	0.989	0.999	0.991
DONE1C	110kV	0.994	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.001	0.988	0.998	0.984	0.987	0.997	0.990	0.998	0.989	0.999	0.991
DONE1B	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.001	0.987	0.998	0.984	0.987	0.997	0.990	0.998	0.989	0.999	0.991
DONE1D	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.001	0.987	0.998	0.984	0.987	0.997	0.990	0.998	0.989	0.999	0.991
DONE1A	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.001	0.987	0.998	0.984	0.987	0.997	0.990	0.998	0.989	0.999	0.991
DRUM1-	110kV	0.998	0.991	0.999	0.990	0.997	0.997	0.995	0.999	0.995	0.995	0.999	1.000	0.996	1.001	0.993	0.999	0.991	0.991	0.999	0.993	0.998	0.991	0.999	0.993
DUNG1-	110kV	1.012	0.997	1.012	0.997	1.009	1.003	1.005	1.004	1.005	1.005	1.008	1.004	1.006	1.004	1.003	1.003	1.003	0.996	1.002	0.993	1.000	0.991	1.001	0.993
EDEN1A	110kV	0.987	0.985	0.989	0.983	0.988	0.995	0.985	0.998	0.986	0.986	0.991	0.998	0.988	1.000	0.982	0.998	0.978	0.985	0.992	0.988	0.993	0.987	0.995	0.989
EDEN1B	110kV	0.987	0.985	0.988	0.984	0.988	0.995	0.985	0.998	0.986	0.986	0.991	0.999	0.988	1.001	0.982	0.998	0.977	0.985	0.992	0.988	0.993	0.987	0.995	0.989
ENNISKI	110kV	1.019	0.997	1.019	0.997	1.015	1.002	1.010	1.003	1.011	1.011	1.014	1.002	1.010	1.001	1.009	1.000	1.010	0.996	1.015	0.997	1.013	0.996	1.013	0.995
ENNISKI	110kV	1.019	0.999	1.019	0.999	1.015	1.004	1.010	1.004	1.011	1.011	1.013	1.003	1.010	1.002	1.009	1.001	1.010	0.998	1.014	0.999	1.013	0.998	1.012	0.997
FINY1A	110kV	0.993	0.987	0.994	0.986	0.992	0.996	0.990	0.998	0.990	0.990	0.995	0.999	0.992	1.000	0.987	0.998	0.984	0.987	0.997	0.990	0.997	0.988	0.999	0.991
FINY1B	110kV	0.993	0.987	0.994	0.986	0.992	0.996	0.990	0.998	0.990	0.990	0.995	0.999	0.992	1.000	0.987	0.998	0.984	0.987	0.997	0.990	0.997	0.988	0.999	0.991
GLEN1A	110kV	0.990	0.984	0.991	0.983	0.989	0.993	0.987	0.996	0.988	0.988	0.994	0.997	0.989	0.998	0.984	0.996	0.981	0.985	0.995	0.988	0.995	0.986	0.997	0.989
HANA1A	110kV	0.993	0.986	0.993	0.986	0.992	0.996	0.989	0.998	0.990	0.990	0.995	0.999	0.992	1.000	0.987	0.998	0.984	0.987	0.997	0.990	0.997	0.988	0.998	0.991
HANA2A	275kV	0.990	0.985	0.991	0.984	0.990	0.994	0.987	0.996	0.988	0.988	0.993	0.997	0.990	0.999	0.985	0.997	0.982	0.985	0.994	0.988	0.994	0.987	0.996	0.989
KELS1-	110kV	0.988	0.982	0.989	0.981	0.988	0.992	0.985	0.994	0.986	0.986	0.992	0.996	0.988	0.997	0.983	0.995	0.979	0.983	0.993	0.987	0.993	0.984	0.994	0.987
KELS2-	275kV	0.987	0.982	0.988	0.982	0.987	0.991	0.985	0.993	0.985	0.985	0.991	0.995	0.987	0.997	0.982	0.994	0.979	0.983	0.992	0.987	0.991	0.984	0.993	0.986
KILR2-	275kV	0.987	0.982	0.987	0.981	0.986	0.991	0.984	0.993	0.985	0.985	0.991	0.995	0.986	0.996	0.981	0.994	0.978	0.983	0.991	0.986	0.990	0.983	0.992	0.986
KNCK1A	110kV	0.994	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.000	0.988	0.998	0.985	0.987	0.998	0.991	0.998	0.989	0.999	0.991
KNCK1B	110kV	0.994	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.996	0.999	0.992	1.000	0.988	0.998	0.985	0.987	0.998	0.991	0.998	0.989	0.999	0.991
LARN1A	110kV	0.987	0.983	0.988	0.982	0.987	0.993	0.984	0.995	0.986	0.986	0.991	0.997	0.987	0.998	0.981	0.996	0.977	0.983	0.991	0.987	0.992	0.985	0.993	0.987
LARN1B	110kV	0.987	0.983	0.988	0.982	0.987	0.993	0.984	0.995	0.986	0.986	0.991	0.997	0.987	0.998	0.981	0.996	0.977	0.983	0.991	0.987	0.992	0.985	0.993	0.987
LIMA1-	110kV	0.997	0.985	0.998	0.984	0.993	0.989	0.989	0.991	0.990	0.990	0.993	0.991	0.991	0.992	0.988	0.991	0.988	0.983	1.005	0.993	0.997	0.985	0.998	0.988
LISB1A	110kV	0.995	0.988	0.995	0.987	0.994	0.997	0.991	0.999	0.992	0.992	0.996	0.999	0.993	1.001	0.989	0.999	0.986	0.988	0.998	0.991	0.998	0.989	1.000	0.992

		Jan		Feb		March		April		May		June		July		August		September		October		November		December	
		Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
LISB1B	110kV	0.995	0.988	0.995	0.987	0.994	0.997	0.991	0.999	0.992	0.992	0.997	0.999	0.993	1.001	0.989	0.999	0.986	0.988	0.998	0.991	0.998	0.990	0.999	0.992
LSMR1A	110kV	0.989	0.980	0.990	0.979	0.985	0.983	0.981	0.985	0.982	0.982	0.986	0.986	0.984	0.987	0.980	0.986	0.981	0.979	0.998	0.989	0.989	0.981	0.990	0.983
LSMR1B	110kV	0.989	0.980	0.990	0.979	0.985	0.983	0.981	0.985	0.982	0.982	0.986	0.986	0.984	0.987	0.980	0.986	0.981	0.979	0.998	0.989	0.989	0.981	0.990	0.983
LOGE1A	110kV	1.003	0.989	1.003	0.988	0.999	0.994	0.994	0.996	0.995	0.995	0.999	0.996	0.996	0.997	0.993	0.995	0.993	0.987	1.010	0.996	1.003	0.989	1.004	0.992
LOGE1B	110kV	1.003	0.989	1.003	0.988	0.999	0.994	0.994	0.996	0.995	0.995	0.999	0.996	0.996	0.997	0.993	0.995	0.993	0.987	1.010	0.996	1.003	0.989	1.004	0.992
MAGF2-	275kV	0.989	0.984	0.990	0.983	0.988	0.991	0.985	0.993	0.986	0.986	0.991	0.995	0.988	0.996	0.983	0.994	0.981	0.984	0.994	0.988	0.992	0.985	0.993	0.987
BALLYCR	275kV	0.985	0.982	0.986	0.980	0.985	0.992	0.983	0.994	0.984	0.984	0.989	0.995	0.985	0.997	0.980	0.995	0.976	0.982	0.990	0.985	0.990	0.983	0.991	0.985
BALLYCR	275kV	0.985	0.982	0.986	0.980	0.985	0.992	0.983	0.994	0.984	0.984	0.989	0.995	0.985	0.997	0.980	0.995	0.976	0.982	0.990	0.985	0.990	0.983	0.991	0.985
NARD1A	110kV	0.997	0.989	0.997	0.988	0.996	0.998	0.993	1.000	0.994	0.994	0.998	1.001	0.995	1.002	0.990	1.000	0.987	0.989	1.001	0.993	1.001	0.991	1.002	0.993
NARD1B	110kV	0.997	0.989	0.997	0.988	0.996	0.998	0.993	1.000	0.994	0.994	0.998	1.001	0.995	1.002	0.990	1.000	0.987	0.989	1.001	0.993	1.001	0.991	1.002	0.993
NEWY1A	110kV	1.005	0.995	1.005	0.995	1.003	1.002	1.000	1.004	1.001	1.001	1.004	1.004	1.001	1.005	0.998	1.003	0.996	0.995	1.006	0.998	1.006	0.996	1.007	0.999
NEWY1B	110kV	1.005	0.995	1.005	0.995	1.003	1.002	1.000	1.004	1.001	1.001	1.004	1.004	1.001	1.005	0.998	1.003	0.996	0.995	1.006	0.998	1.006	0.996	1.007	0.999
NORF1A	110kV	0.989	0.983	0.990	0.982	0.989	0.992	0.986	0.995	0.987	0.987	0.993	0.996	0.989	0.998	0.984	0.995	0.980	0.984	0.994	0.987	0.994	0.985	0.995	0.988
NORF1B	110kV	0.989	0.983	0.990	0.982	0.989	0.992	0.986	0.995	0.987	0.987	0.993	0.996	0.989	0.998	0.984	0.995	0.980	0.984	0.994	0.987	0.994	0.985	0.995	0.988
OMAH1-	110kV	1.011	0.994	1.011	0.993	1.007	0.999	1.002	0.999	1.003	1.003	1.006	0.998	1.003	0.998	1.001	0.997	1.002	0.992	1.007	0.994	1.004	0.991	1.004	0.991
RATH1A	110kV	0.998	0.990	0.999	0.989	0.997	0.999	0.994	1.001	0.995	0.995	1.000	1.002	0.996	1.003	0.992	1.001	0.989	0.990	1.002	0.994	1.002	0.992	1.004	0.994
RATH1B	110kV	0.998	0.990	0.999	0.989	0.997	0.999	0.994	1.001	0.995	0.995	1.000	1.002	0.996	1.003	0.992	1.001	0.989	0.990	1.002	0.994	1.002	0.992	1.004	0.994
ROSE1A	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.995	0.999	0.992	1.000	0.987	0.998	0.985	0.987	0.997	0.990	0.997	0.989	0.999	0.991
ROSE1B	110kV	0.993	0.987	0.994	0.986	0.993	0.996	0.990	0.998	0.991	0.991	0.995	0.999	0.992	1.000	0.987	0.998	0.985	0.987	0.997	0.990	0.997	0.989	0.999	0.991
STRABAN	110kV	0.996	0.983	0.996	0.983	0.992	0.986	0.987	0.988	0.988	0.988	0.991	0.988	0.989	0.988	0.986	0.987	0.987	0.981	1.000	0.989	0.993	0.982	0.993	0.984
STRABAN	110kV	0.997	0.983	0.998	0.983	0.993	0.986	0.989	0.988	0.990	0.990	0.992	0.988	0.989	0.988	0.987	0.987	0.988	0.981	1.000	0.988	0.993	0.982	0.993	0.983
TAND1A	110kV	0.996	0.990	0.997	0.989	0.994	0.996	0.993	0.998	0.993	0.993	0.997	0.999	0.994	1.000	0.991	0.998	0.989	0.989	0.997	0.992	0.997	0.990	0.998	0.992
TAND1B	110kV	0.996	0.990	0.997	0.989	0.994	0.996	0.993	0.998	0.993	0.993	0.997	0.999	0.994	1.000	0.991	0.998	0.989	0.989	0.997	0.992	0.997	0.990	0.998	0.992
TANDRAG	275kV	0.993	0.987	0.993	0.987	0.991	0.994	0.989	0.996	0.990	0.990	0.994	0.997	0.991	0.998	0.987	0.996	0.985	0.987	0.996	0.991	0.995	0.989	0.996	0.991
COALISL	110kV																			0.997	0.991	0.996	0.989	0.997	0.990
COALISL	275kV																			0.995	0.990	0.994	0.987	0.995	0.989
WARN1A	110kV	0.998	0.991	0.999	0.991	0.996	0.997	0.995	0.999	0.995	0.995	0.999	1.000	0.996	1.001	0.992	0.999	0.990	0.991	0.999	0.993	0.999	0.992	1.000	0.994
WARN1B	110kV	0.998	0.991	0.999	0.991	0.996	0.997	0.995	0.999	0.995	0.995	0.999	1.000	0.996	1.001	0.992	0.999	0.990	0.991	0.999	0.993	0.999	0.992	1.000	0.994
WEST1A	110kV	0.995	0.988	0.996	0.987	0.994	0.998	0.991	1.000	0.992	0.992	0.997	1.000	0.994	1.002	0.989	0.999	0.986	0.988	0.999	0.991	0.999	0.990	1.001	0.992
WEST1B	110kV	0.995	0.988	0.996	0.987	0.994	0.998	0.991	1.000	0.992	0.992	0.997	1.000	0.994	1.002	0.989	0.999	0.985	0.988	0.999	0.991	0.999	0.990	1.001	0.992

Indicative TUoS Tariff Analysis

Appendix J
Indicative Tariffs 2008/2009

Table 16 below (shown over 5 pages) outlines the indicative tariff for each unit in the tariff period 2008/2009. Generators connected to the distribution system with Contracted Capacity of 5MW and above have been included in the tariff studies. A number of generators may be connected at one node, in this case the same tariff shall apply to each generator unit.

Table 22: Indicative tariffs for tariff period 2008/2009 under the five possible Options

INDICATIVE 2008/2009 ALL-ISLAND CAPACITY BASED GENERATOR TUOS CHARGES					
	Option 1	Option 2	Option 3	Option 4	Option 5
Generator Unit/Connected at	Indicative tariffs	Indicative tariffs	Indicative tariffs	Indicative tariffs	Indicative Tariffs
Ardnacrusha	7.3498	6.0870	11.4493	5.7751	5.7249
Arigna_Wind	5.5836	8.8042	7.1675	6.3540	5.7249
Arklow Wind	1.2646	8.1238	-7.8979	6.2091	5.7249
Ballylickey	6.1352	-6.8662	7.8580	3.0156	5.7249
Binbane	10.9091	30.4354	22.1708	10.9624	5.7249
Bellacorrick	5.2095	18.3530	4.5702	8.3883	5.7249
Bandon	4.3667	-4.1461	4.4583	3.5951	5.7249
Butlerstown	-0.3799	6.4047	-9.6933	5.8428	5.7249
Corderry	6.8154	7.4434	10.5823	6.0641	5.7249
Clahane	11.7676	9.5383	25.1915	6.5104	5.7249
Castlebar	3.6048	25.9259	-0.1671	10.0017	5.7249
Erne (Cathleen's Fall ER1, ER2)	10.6471	6.7409	22.1708	5.9145	5.7249
Crane	4.4322	20.1733	3.2058	8.7761	5.7249
Carlow	1.6552	9.9343	-5.2182	6.5948	5.7249
Dundalk	-0.6354	0.0962	-11.9555	4.4989	5.7249
Drybridge	2.7255	5.6357	-2.8311	5.6790	5.7249
Dunmanway	5.8732	-6.8662	7.8580	3.0156	5.7249
Dallow	6.5469	10.7935	9.4183	6.7778	5.7249
Galway	6.0743	9.9211	9.6462	6.5920	5.7249
Glenlara	6.4724	4.1560	8.2875	5.3638	5.7249
Ikerrin	4.9866	8.4110	3.4225	6.2703	5.7249

INDICATIVE 2008/2009 ALL-ISLAND CAPACITY BASED GENERATOR TUOS CHARGES					
Generator Unit/Connected at	**Option 1 Indicative tariffs**	**Option 2 Indicative tariffs**	**Option 3 Indicative tariffs**	**Option 4 Indicative tariffs**	**Option 5 Indicative Tariffs**
Knockeragh	7.8840	14.3420	12.0804	7.5338	5.7249
Letterkenny	13.4795	27.1371	32.6973	10.2597	5.7249
Meath Hill	0.6421	12.3337	-8.2962	7.1060	5.7249
Macroom	7.3903	4.8989	11.2899	5.5220	5.7249
Mallow	5.5062	3.0451	6.6052	5.1271	5.7249
Moy	6.4499	12.6009	7.7424	7.1629	5.7249
Shankill	1.6811	-5.8062	-6.7365	3.2414	5.7249
Sorne Hill	13.7415	27.1371	32.6973	10.2597	5.7249
Somerset	5.4579	9.1026	5.7320	6.4176	5.7249
Tullabrack	10.4574	7.1168	22.7958	5.9945	5.7249
Trien	10.9044	9.8101	22.7786	6.5683	5.7249
Tralee	11.0967	9.6376	23.4633	6.5316	5.7249
Tonroe	4.4821	33.8202	3.4553	11.6835	5.7249
Trillick	13.7415	27.1371	32.6973	10.2597	5.7249
Wexford	3.0415	15.1363	-0.2606	7.7030	5.7249
Aghada 220KV	2.8905	14.1934	-1.1767	7.5022	5.7249
Athea	10.9044	9.9186	22.7786	6.5914	5.7249
Ballywater	4.4322	20.1733	3.2058	8.7761	5.7249
Booltiagh	9.3650	7.1168	18.3395	5.9945	5.7249
Lee (Carrigadrohid)	6.7158	4.8033	10.8214	5.5017	5.7249
Erne (Cliff) ER3, ER4	11.1761	6.7420	23.2601	5.9147	5.7249

INDICATIVE 2008/2009 ALL-ISLAND CAPACITY BASED GENERATOR TUOS CHARGES					
Generator Unit/Connected at	Option 1 Indicative tariffs	Option 2 Indicative tariffs	Option 3 Indicative tariffs	Option 4 Indicative tariffs	Option 5 Indicative Tariffs
Coomacheo	9.9877	21.9496	19.2318	9.1545	5.7249
Cunghill	7.8189	4.3243	12.6168	5.3996	5.7249
Cushaling	6.3108	18.5250	9.7786	8.4250	5.7249
Coomagearlaghy	9.9877	18.6796	19.2319	8.4579	5.7249
Derrybrien	9.4824	8.1885	19.2535	6.2229	5.7249
Rhode (Derryiron RH1 ,RH2)	-0.2336	-0.9767	-11.7936	4.2703	5.7249
Glanlee	9.9877	18.6790	19.2322	8.4578	5.7249
Great Island 110kV GI1, GI2	1.0623	6.9787	-6.0087	5.9651	5.7249
Great Island 220kV GI3	2.2345	8.8454	-4.0960	6.3628	5.7249
Golagh	11.8287	14.3900	26.3653	7.5440	5.7249
Huntstown CT, ST	6.0876	9.2117	5.7498	6.4408	5.7249
Huntstown 2	6.4253	9.2906	6.3045	6.4576	5.7249
Lee Inniscarra LE1, LE2	6.2116	3.2425	7.4854	5.1692	5.7249
Dublin Bay Power - Irishtown	5.5681	9.0560	4.2916	6.4077	5.7249
Lough Ree Power (Lanesboro)	6.4415	3.8581	7.7706	5.3003	5.7249
Moneypoint 1, 2 & 3	8.3831	17.3976	14.1827	8.1848	5.7249
Marina MR1, MRT	4.0467	0.9527	3.4245	4.6813	5.7249
Meentycat	14.0304	24.2568	34.0156	9.6461	5.7249
North Wall 38kV	5.4697	9.2118	5.7498	6.4409	5.7249
North Wall 220kV	6.7403	9.1284	7.4776	6.4231	5.7249

INDICATIVE 2008/2009 ALL-ISLAND CAPACITY BASED GENERATOR TUOS CHARGES					
Generator Unit/Connected at	Option 1 Indicative tariffs	Option 2 Indicative tariffs	Option 3 Indicative tariffs	Option 4 Indicative tariffs	Option 5 Indicative Tariffs
Liffey (Pollaphuca)	3.8791	9.9359	2.7051	6.5951	5.7249
Poolbeg 1, 2 & 3	5.0076	8.8897	4.1249	6.3722	5.7249
Ratrussan (Bindoo)	2.4544	-4.4603	-3.6353	3.5281	5.7249
Mountain Lodge	2.4544	-4.4603	-3.6353	3.5281	5.7249
West Offaly Power (Shannonbridge)	6.2857	10.2298	7.8076	6.6577	5.7249
Poolbeg 4, 5 & 6	5.7176	9.0811	4.6141	6.4130	5.7249
Aughinish (Seal Rock)	11.7121	6.2310	25.5180	5.8058	5.7249
Tarbert 110kV TB1, TB2	8.9025	6.9196	17.0104	5.9525	5.7249
Tarbert 220kV TB3, TB4	8.0355	6.4487	16.6180	5.8522	5.7249
Tynagh	8.7575	12.4312	15.2516	7.1267	5.7249
Turlough Hill (TH1 -TH4)	6.8274	8.8396	10.1496	6.3616	5.7249
Tawnaghamore	6.7835	12.5972	7.9256	7.1621	5.7249
Coleraine	0.7448	-9.4275	-10.8468	2.4699	5.7249
Ballymena	0.4006	-9.5772	-11.0651	2.4380	5.7249
Enniskillen	3.8670	-7.5739	3.2190	2.8648	5.7249
Larne	0.7069	-9.6760	-8.8846	2.4170	5.7249
Omagh	0.7917	-7.5746	-8.1141	2.8647	5.7249
Strabane	1.5556	-12.4029	-7.6090	1.8360	5.7249
Limavady	2.7749	-9.4069	-7.5847	2.4743	5.7249
Aghyoule	4.7536	-7.5742	6.7106	2.8647	5.7249
Lisamore	-0.1732	-9.3699	-13.9891	2.4822	5.7249

INDICATIVE 2008/2009 ALL-ISLAND CAPACITY BASED GENERATOR TUOS CHARGES					
Generator Unit/Connected at	**Option 1 Indicative tariffs**	**Option 2 Indicative tariffs**	**Option 3 Indicative tariffs**	**Option 4 Indicative tariffs**	**Option 5 Indicative Tariffs**
Ballylumford G4, G5, G6	3.0102	-9.3602	-4.5944	2.4843	5.7249
Ballylumford Gas Turbine 1 & 2	3.5909	-9.6806	-0.9689	2.4160	5.7249
Ballylumford CCGT20	2.5097	-9.3615	-5.9516	2.4840	5.7249
Ballylumford CCGT10	3.3455	-9.6820	-1.7707	2.4157	5.7249
Coolkeeragh CCGT	3.6944	-9.3716	-2.5794	2.4818	5.7249
Coolkeeragh Unit 8	3.8921	-9.3701	-1.8329	2.4822	5.7249
Kilroot G1 & G2	2.3931	-9.8558	-5.7266	2.3787	5.7249
Kilroot Gas Turbine 1 & 2	2.3527	-9.8561	-5.7606	2.3786	5.7249

Appendix K
Statistics for Indicative Tariffs 2008/2009

The table below outlines some statistics associated with the indicative 2008/2009 tariffs outlined in Appendix J above.

Table 23: Statistics associated with each possible option based on indicative tariffs for tariff period 2008/2009

	Option 1 Statistics	Option 2 Statistics	Option 3 Statistics	Option 4 Statistics	Option 5 Statistics
Minimum tariff	-0.6354	-12.4029	-13.9891	1.8360	5.7249
Maximum tariff	14.0304	33.8202	34.0156	11.6835	5.7249
Range	14.6658	46.2231	48.0047	9.8474	0
Standard deviation	3.6612	10.8156	11.7075	2.3042	0
Annual Revenue requirement (€m)	57.08	57.08	57.08	57.08	57.08

Appendix L
Indicative Tariffs 2014
Static Models

The table below (shown over 3 pages) outlines the indicative tariff for each unit that has been calculated for tariff period 2013/2014 using Option 1 and Option 3 which are both based on a static network model. In addition appendix N shows how the 2013/2014 indicative tariffs compare to the indicative tariffs for 2008/2009 calculated using the same methodologies. This analysis allows us to assess the potential volatility of Options 1 and Option 3.

It is not possible at this time to develop indicative tariffs for 2013/2014 for Option 2 or Option 4 as these as these would require future network scenarios based on 2018/2019 and this data is not available at this time.

Table 24: Indicative tariff for 2013/2014 using option 1 and option 3

Generator Unit/ Connected at	Option 1 2014 Indicative tariffs	Option 3 2014 Indicative tariffs
Ardnacrusha	3.7073	3.0851
Arigna_Wind	6.3602	12.2037
Agann	5.7789	10.8638
Arklow Wind	0.1852	-12.3604
Athea	7.1408	16.7552
Athlone	2.0608	-5.5750
Ballylickey	7.2137	16.8360
Binbane	10.4506	25.6645
Bellacorrick	5.1011	8.0063
Bandon	6.6003	16.0747
Butlerstown	2.6114	-2.3135
Clashavoon	8.0621	20.9399
Clonkeen	9.3771	27.2040
Corderry	6.8553	14.9929
Clahane	7.4578	17.2941
Castlebar	3.5200	1.2827
Erne (Cathleen's Fall ER1, ER2)	9.4335	26.0472
Cahie	2.9522	-1.2072
New garrow	9.3947	27.2425
Crane	1.6137	-7.1490
Carlow	0.0796	-13.1194
Dundalk	0.4870	-10.8345
Dungarven	3.8230	4.1294
Drybridge	0.0370	-15.6944
Dunmanway	7.0233	16.8360
Dallow	3.4641	0.7742
Dalton	2.6984	-1.8935
Enniskillen	4.8555	5.6931
Galway	2.0771	-3.7263
Glenlara	4.2811	3.5414
Hartnett's Cross	7.4035	19.7755
Kilkenny	-1.3100	-17.6220
Kiskeam	8.2624	24.8408
Knockeragh	7.7089	19.1963
Knochanure	7.1409	16.7552
Letterkenny	12.4940	38.5600
Louth CCGT	2.1796	-6.1080

Generator Unit/ Connected at	Option 1 2014 Indicative tariffs	Option 3 2014 Indicative tariffs
Lodgewood	2.2151	-6.1524
Midleton	4.4841	9.8840
Meath Hill	1.0848	-7.2475
Macroom	7.5939	19.7755
Moy	6.3177	12.6873
Meentycat	11.9414	36.8699
Navan	0.9233	-12.6028
nenagh	3.7032	5.4966
Oughteragh	5.9989	10.8736
Rathkeale	5.4163	9.3223
Shankill	3.0191	-2.4141
Sligo	6.7828	15.2717
Sorne Hill	12.6843	38.5599
Somerset	2.5934	-3.4026
Tullabrack	6.6862	14.9027
Trien	7.7107	17.8195
Tralee	7.1742	16.5080
Thurles	4.0458	2.8068
Tonroe	5.0116	12.2874
Trillick	12.6843	38.5599
Tipp/ Cappagh	4.7228	5.8761
Woodland	3.1088	-4.7148
White Gen	7.0467	17.8012
Wexford	0.5391	-9.1585
Aghada 220KV	7.0624	17.8952
Ballywater	1.6137	-7.1490
Booltiagh	5.8924	10.4464
Lee (Carrigadrohid)	7.1773	19.5769
Erne (Cliff) ER3, ER4	9.8152	27.1254
Coomacheo	9.3947	27.2425
Cunghill	7.7661	19.7322
Cushaling	2.5384	-4.9488
Coomagearlaghy	9.3771	27.2038
Derrybrien	5.7789	10.8637
Rhode (Derryiron RH1 ,RH2)	0.3884	-10.9612
Glanlee	9.3767	27.2020
Golagh	10.6923	31.0345

Generator Unit/ Connected at	Option 1 2014 Indicative tariffs	Option 3 2014 Indicative tariffs
Huntstown CT, ST	1.8913	-8.4685
Huntstown 2	2.0946	-8.0962
Lee Inniscarra LE1, LE2	6.7698	16.2352
Dublin Bay Power - Irishtown	0.8506	-13.0567
Lough Ree Power (Lanesboro)	3.9453	2.7220
Moneypoint 1, 2 & 3	6.1932	12.0865
Marina	4.9453	11.6290
Meentycat	11.9414	36.8699
North Wall 38kV	1.4421	-8.4693
North Wall 220kV	1.3414	-11.5423
Liffey (Pollaphuca)	1.5034	-5.1972
Ratrussan (Bindoo)	3.4433	-0.7534
Mountain Lodge	3.4433	-0.7534
West Offaly Power (Shannonbridge)	3.2158	-1.1827
Poolbeg 4, 5 & 6	0.9463	-12.7890
Aughinish (Seal Rock)	7.4515	19.1751
Tynagh	4.8946	5.0356
Turlough Hill (TH1 -TH4)	3.1797	-1.0692
Tawnaghamore	6.5063	12.6801
Coleraine	1.9110	-7.8280
Ballymena	3.0000	-2.1585
Enniskillen	2.9288	0.7899
Larne	3.2036	-2.1297
Omagh	2.0832	-6.5669
Strabane	2.9785	0.8183
Limavady	2.3693	-3.6128
Aghyoule	2.9918	0.7896
Dungannon	2.2078	-6.2737
Lisamore	3.3545	0.3511
Ballylumford Gas Turbine 1 & 2	4.6363	3.5806
Ballylumford CCGT20	3.9409	0.2309
Ballylumford CCGT10	4.4602	2.6952
Coolkeeragh CCGT	4.1473	2.9342
Coolkeeragh Unit 8	4.2913	3.7581
Kilroot G1 & G2	4.2582	2.0824
Kilroot OCGT 1 & 2	4.1625	1.9578
Kilroot CCGT1	4.1625	1.9578
Kilroot Gas Turbine 1 & 2	4.2586	2.0850
Glenavy	1.8185	-8.7251

Appendix M
Statistics for Indicative Tariffs 2013/2014

The table below outlines some statistics associated with the indicative 2013/2014 tariffs outlined in Appendix L above.

Table 25: Statistics based on indicative tariff in 2013/3014

	Option 1 Statistics	Option 3 Statistics
Statistics		
Minimum tariff	**-1.31**	**-17.62**
Maximum tariff	**12.68**	**38.56**
Range	**13.99**	**56.18**
Standard deviation	**3.10**	**13.52**

Appendix N
Volatility Analysis

Table 20 (shown over 2 pages) and Figure 19 below show a comparison of indicative tariffs for 2008/2009 and 2013/2014 using option 1. Only units connected to the system in both years have been illustrated in the tables and charts below.

Table 21 (shown over 2 pages) and Figure 20 also show a comparison of indicative tariff for 2008/2009 and 2013/2014 using Option 3. Again only units connected to the system in both years have been illustrated in the tables and charts below.

Note that the axis on the figures below are different scales.

Table 26 : Indicative tariffs for Option 1 in both years

Generator Unit/ Connected at	ID No.	Option 1 Indicative tariffs 2008/2009	Option 1 2014 Indicative tariffs 2014
Ardnacrusha	1	7.3498	3.7073
Arigna_Wind	2	5.5836	6.3602
Arklow Wind	3	1.2646	0.1852
Ballylickey	4	6.1352	7.2137
Binbane	5	10.9091	10.4506
Bellacorrick	6	5.2095	5.1011
Bandon	7	4.3667	6.6003
Butlerstown	8	-0.3799	2.6114
Corderry	9	6.8154	6.8553
Clahane	10	11.7676	7.4578
Castlebar	11	3.6048	3.5200
Erne (Cathleen's Fall ER1, ER2)	12	10.6471	9.4335
Crane	13	4.4322	1.6137
Carlow	14	1.6552	0.0796
Dundalk	15	-0.6354	0.4870
Drybridge	16	2.7255	0.0370
Dunmanway	17	5.8732	7.0233
Dallow	18	6.5469	3.4641
Galway	20	6.0743	2.0771
Glenlara	21	6.4724	4.2811
Ikerrin	22	4.9866	3.7032
Knockeragh	23	7.8840	7.7089
Letterkenny	24	13.4795	12.4940
Meath Hill	25	0.6421	1.0848
Macroom	26	7.3903	7.5939
Mallow	27	5.5062	8.0621
Moy	28	6.4499	6.3177
Shankill	29	1.6811	3.0191
Sorne Hill	30	13.7415	12.6843
Somerset	31	5.4579	2.5934
Tullabrack	32	10.4574	6.6862
Trien	33	10.9044	7.7107
Tralee	34	11.0967	7.1742
Tonroe	35	4.4821	5.0116
Trillick	36	13.7415	12.6843
Wexford	37	3.0415	0.5391
Aghada 220KV	42	2.8905	7.0624
Athea	46	10.9044	7.1408
Ballywater	47	4.4322	1.6137
Booltiagh	48	9.3650	5.8924
Lee (Carrigadrohid)	49	6.7158	7.1773
Erne (Cliff) ER3, ER4	52	11.1761	9.8152

Generator Unit/ Connected at	ID No.	Option 1 Indicative tariffs 2008/2009	Option 1 2014 Indicative tariffs 2014
Coomacheo	54	9.9877	9.3947
Cunghill	55	7.8189	7.7661
Cushaling	56	6.3108	2.5384
Coomagearlaghy	57	9.9877	9.3771
Derrybrien	58	9.4824	5.7789
Rhode (Derryiron RH1 ,RH2)	59	-0.2336	0.3884
Glanlee	61	9.9877	9.3767
Golagh	62	11.8287	10.6923
Huntstown CT, ST	63	6.0876	1.8913
Huntstown 2	65	6.4253	2.0946
Lee Inniscarra LE1, LE2	66	6.2116	6.7698
Dublin Bay Power - Irishtown	67	5.5681	0.8506
Lough Ree Power (Lanesboro)	68	6.4415	3.9453
Moneypoint 1, 2 & 3	69	8.3831	6.1932
Marina MR1, MRT	72	4.0467	4.9453
Meentycat	73	14.0304	11.9414
North Wall 38kV	74	5.4697	1.4421
North Wall 220kV	75	6.7403	1.3414
Liffey (Pollaphuca)	77	3.8791	1.5034
Ratrussan (Bindoo)	78	2.4544	3.4433
Mountain Lodge	79	2.4544	3.4433
West Offaly Power (Shannonbridge)	80	6.2857	3.2158
Poolbeg 4, 5 & 6	82	5.7176	0.9463
Aughinish (Seal Rock)	85	11.7121	7.4515
Tynagh	87	8.7575	4.8946
Turlough Hill (TH1 -TH4)	89	6.8274	3.1797
Tawnaghamore	93	6.7835	6.5063
Coleraine	94	0.7448	1.9110
Ballymena	95	0.4006	3.0000
Enniskillen	96	3.8670	2.9288
Larne	97	0.7069	3.2036
Omagh	98	0.7917	2.0832
Strabane	99	1.5556	2.9785
Limavady	100	2.7749	2.3693
Aghyoule	101	4.7536	2.9918
Lisamore	102	-0.1732	3.3545
Ballylumford Gas Turbine 1 & 2	103	3.5909	4.6363
Ballylumford CCGT20	105	2.5097	3.9409
Ballylumford CCGT10	108	3.3455	4.4602
Coolkeeragh CCGT	109	3.6944	4.1473
Coolkeeragh Unit 8	111	3.8921	4.2913
Kilroot G1 & G2	113	2.3931	4.2582
Kilroot Gas Turbine 1 & 2	114	2.3527	4.2586

Table 27 : Indicative tariffs for Option 3 in both years

Generator Name/ Connected at	Unit ID No.	Option 3 Indicative tariffs 2008/2009	Option 3 Indicative tariffs 2014
Ardnacrusha	1	11.4493	3.0851
Arigna_Wind	2	7.1675	12.2037
Arklow Wind	3	-7.8979	-12.3604
Ballylickey	4	7.8580	16.8360
Binbane	5	22.1708	25.6645
Bellacorrick	6	4.5702	8.0063
Bandon	7	4.4583	16.0747
Butlerstown	8	-9.6933	-2.3135
Corderry	9	10.5823	14.9929
Clahane	10	25.1915	17.2941
Castlebar	11	-0.1671	1.2827
Erne (Cathleen's Fall ER1, ER2)	12	22.1708	26.0472
Crane	13	3.2058	-7.1490
Carlow	14	-5.2182	-13.1194
Dundalk	15	-11.9555	-10.8345
Drybridge	16	-2.8311	-15.6944
Dunmanway	17	7.8580	16.8360
Dallow	18	9.4183	0.7742
Galway	20	9.6462	-3.7263
Glenlara	21	8.2875	3.5414
Ikerrin	22	3.4225	5.4966
Knockeragh	23	12.0804	19.1963
Letterkenny	24	32.6973	38.5600
Meath Hill	25	-8.2962	-7.2475
Macroom	26	11.2899	19.7755
Mallow	27	6.6052	n/a
Moy	28	7.7424	12.6873
Shankill	29	-6.7365	-2.4141
Sorne Hill	30	32.6973	38.5599
Somerset	31	5.7320	-3.4026
Tullabrack	32	22.7958	14.9027
Trien	33	22.7786	17.8195
Tralee	34	23.4633	16.5080
Tonroe	35	3.4553	12.2874
Trillick	36	32.6973	38.5599
Wexford	37	-0.2606	-9.1585
Aghada 220KV	42	-1.1767	17.8952
Athea	46	22.7786	16.7552
Ballywater	47	3.2058	-7.1490
Booltiagh	48	18.3395	10.4464
Lee (Carrigadrohid)	49	10.8214	19.5769
Erne (Cliff) ER3, ER4	52	23.2601	27.1254

Generator Name/ Connected at	ID No.	Option 3 Indicative tariffs 2008/2009	Option 3 Indicative tariffs 2014
Coomacheo	54	19.2318	27.2425
Cunghill	55	12.6168	19.7322
Cushaling	56	9.7786	-4.9488
Coomagearlaghy	57	19.2319	27.2038
Derrybrien	58	19.2535	10.8637
Rhode (Derryiron RH1 ,RH2)	59	-11.7936	-10.9612
Glanlee	61	19.2322	27.2020
Golagh	62	26.3653	31.0345
Huntstown CT, ST	63	5.7498	-8.4685
Huntstown 2	65	6.3045	-8.0962
Lee Inniscarra LE1, LE2	66	7.4854	16.2352
Dublin Bay Power - Irishtown	67	4.2916	-13.0567
Lough Ree Power (Lanesboro)	68	7.7706	2.7220
Moneypoint 1, 2 & 3	69	14.1827	12.0865
Marina MR1, MRT	72	3.4245	11.6290
Meentycat	73	34.0156	36.8699
North Wall 38kV	74	5.7498	-8.4693
North Wall 220kV	75	7.4776	-11.5423
Liffey (Pollaphuca)	77	2.7051	-5.1972
Ratrussan (Bindoo)	78	-3.6353	-0.7534
Mountain Lodge	79	-3.6353	-0.7534
West Offaly Power (Shannonbridg	80	7.8076	-1.1827
Poolbeg 4, 5 & 6	82	4.6141	-12.7890
Aughinish (Seal Rock)	85	25.5180	19.1751
Tynagh	87	15.2516	5.0356
Turlough Hill (TH1 -TH4)	89	10.1496	-1.0692
Tawnaghamore	93	7.9256	12.6801
Coleraine	94	-10.8468	-7.8280
Ballymena	95	-11.0651	-2.1585
Enniskillen	96	3.2190	0.7899
Larne	97	-8.8846	-2.1297
Omagh	98	-8.1141	-6.5669
Strabane	99	-7.6090	0.8183
Limavady	100	-7.5847	-3.6128
Aghyoule	101	6.7106	0.7896
Lisamore	102	-13.9891	0.3511
Ballylumford Gas Turbine 1 & 2	103	-0.9689	3.5806
Ballylumford CCGT20	105	-5.9516	0.2309
Ballylumford CCGT10	108	-1.7707	2.6952
Coolkeeragh CCGT	109	-2.5794	2.9342
Coolkeeragh Unit 8	111	-1.8329	3.7581
Kilroot G1 & G2	113	-5.7266	2.0824
Kilroot Gas Turbine 1 & 2	114	-5.7606	2.0850

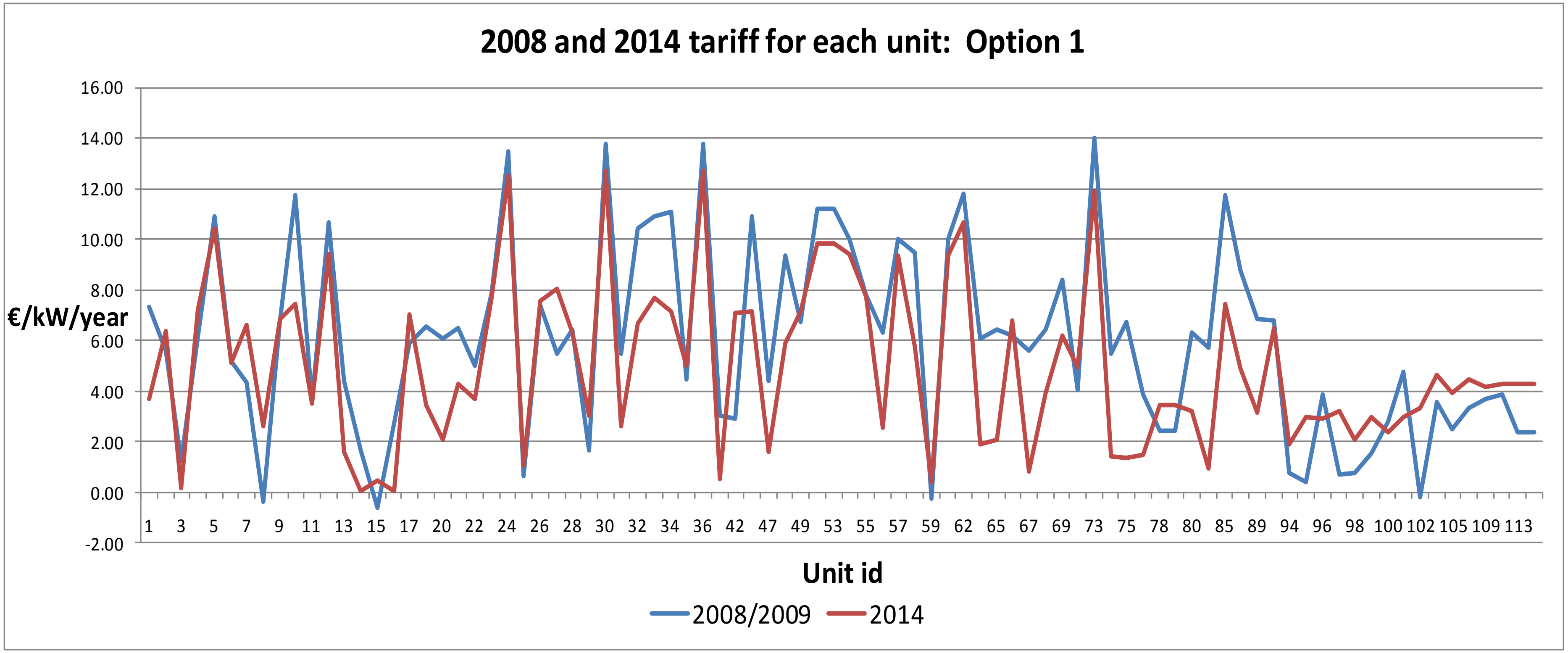


Figure 29: Volatility analysis for Option 1

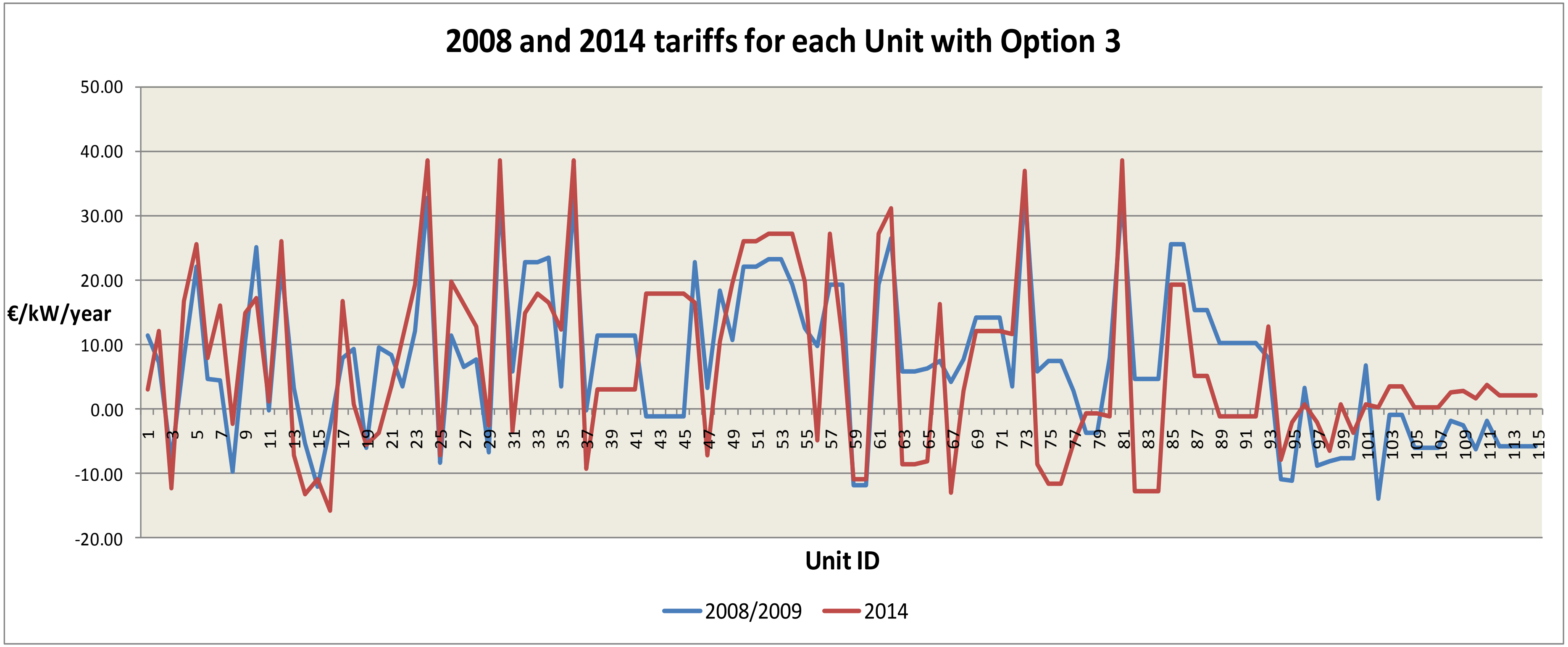


Figure 30: Volatility Analysis for Option 3

Appendix O
Dispatch Scenarios

Each scenario is based upon merit order dispatch in order for generation to meet the associated demand.

Winter Peak with 0% wind penetration

This scenario comprises a merit order under maximum demand conditions and is representative of the system's ability to accommodate flows at peak demand. There is zero percent wind penetration assumed under this dispatch. A high wind scenario at winter peak is not included in the package as the ability of the system to accommodate wind export from a particular region is more stressed under either the Summer Peak or Summer Minimum conditions when local load will be lower.

Summer Peak

The Summer Peak refers to the average week-day peak value between March and September inclusive, which is typically 20% lower than the winter peak. This demand level is of interest because although the overall grid power flow may be lower in summer than in winter, this may not be the case for flows on all circuits. In addition, the capacity of overhead lines is lower because of higher ambient temperatures, while network maintenance, normally carried out in the March to September period, can deplete the network, further reducing its capability to transport power. Summer Peak is examined under two separate scenarios, one with zero wind and one with high wind.

- *With 80% wind penetration*

A high, yet realistic level of wind penetration is included in this scenario. While penetration up to 100% would be considered at the 'local' level the

System Operators believe 80% to be a reasonable balance between local or regional considerations and wider backbone system development.

- *With 0% wind penetration*

This scenario looks at the ability of a merit order of the conventional plant portfolio to meet peak demand in the summer conditions when the equipment ratings are somewhat lower due to ambient temperatures. In addition, when compared to the winter peak it tests the system's ability to respond to a uniform or dispersed reduction of demand being served from a smaller number of discrete generating units with consequential potential for higher bulk power transfer on the network.

Summer Minimum with 80% wind penetration

The Summer Valley is the annual minimum which generally occurs in August. Annual minimum demand is typically 36% of the annual maximum demand. Analysis of summer valley cases is concerned with the impact of low demand and low levels of generation. This minimum condition is of particular interest when assessing the capability to connect new generation. With local demand at a minimum, the connecting generator must export more of its power across the grid than at peak times. A high level of wind penetration is chosen as this represents testing conditions for the export of wind power from geographically remote regions with limited demand. As with the summer peak scenario, the 80% penetration is considered to be a reasonable balance between local or regional considerations and wider backbone system development. In this scenario a small portfolio of conventional plant will be required to meet dispersed system demand conditions.

Examples of Network Developments using the four dispatch scenarios which are utilised in the locational tariff methodologies, Options 1 to 4 inclusive.

Arva – Shankill 110 kV project: A second 110 kV line between Arva and Shankill stations; required to alleviate overloads under maintenance-trip conditions at summer peak, regardless of wind output.

Lodgewood 220 / 110 kV project: A new 220/110 kV station in county Wexford, connected into the Arklow–Great Island 220 kV line, and linked with a new Crane–Lodgewood 110 kV line, through a 250 MVA 220/110 kV transformer. This is required to satisfy security of supply requirements in Wexford which is tested at Summer Peak, with or without wind. It is also required to resolve potential low voltages at winter peak.

Uprating of the three 110 kV lines from Cathaleen's Fall to Sligo, Corderry and Coraclassy [under consideration]: The requirement to uprate these lines was identified in studies for summer peak and summer minimum conditions with wind high. It is intended to proceed with these projects in the near future.

Reinforcement to Castlebar (Co. Mayo): a new 110kV circuit required to reinforcement the transmission network to Castlebar. This is required to alleviate overloads under maintenance-trip conditions at summer peak low wind conditions. This and future reinforcements will be required to cater for future expected generator connections in the area at summer peak and summer min conditions both with high wind.

Binbane - Letterkenny 110kV project (Co. Donegal): a new 110kV circuit required between Binbane and Letterkenny 110kV stations in Co. Donegal. This is required to satisfy security of supply requirements in Donegal which is tested at summer peak with low and high wind and summer min with high wind.

Gate 2 related projects in south-west: 2 220kV stations required to accommodate the expected connection of Gate 2 generation in the south-west i.e. Kerry/Cork area. These projects are required to divert power onto the 220kV network in order to reduce the risk of overloading the local 110kV network which could occur in high wind conditions.

2nd North – South interconnector: 400kV project which in totality is planned to link Woodland 400kV station near Dublin to a new 400kV/275kV station in Co. Tyrone via a new 400kV/220kV station in Co. Cavan. This project is required to reinforce the system in the north east and also to accommodate safe bulk power transfers between NI and ROI primarily at peak conditions.