



## **Joint TSO/DSO Group Processing Approach**

### **Charging and Rebating Principles**

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## 1 Introduction

Group processing of connection offers for renewable generation is a strategic approach to connection offer processing that was proposed by the **System Operators**<sup>1</sup> in 2004 and approved by the **Commission for Energy Regulation (CER)**. The **Group Processing Approach (GPA)** enables the System Operators to process a pre-defined number of connection offers concurrently rather than having to treat each application on an individual independent basis, as had been the case before Group Processing was introduced.

The purpose of this paper is to provide applicants seeking to connect under the GPA with a clear set of guidelines explaining the rationale behind how projects are charged for connection, and when and how they will be rebated in the event that another party connects to the asset for which they had paid. Please note that while this paper is intended primarily to cover the GPA the general policies outlined are also applicable to demand connections at transmission level<sup>2</sup>.

In addition, a separate, complementary paper on connection offer policy will also be published focussing on aspects of GPA connection policy which is not purely related to charging and rebating.

These two documents taken together will supersede the Pricing Principles Guidelines first approved and published in February 2007.

The information contained in this paper applies for the most part to both System Operators, i.e. it covers both the Transmission and Distribution Systems. Where policy differences between the System Operators exist, these are clearly stated.

The policies outlined in this paper generally apply to all categories of generators processed under the Group Processing Approach unless stated otherwise. This includes conventional plant, wind farms, pumped storage units and interconnectors.

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<sup>1</sup> EirGrid plc. as the Transmission System Operator and ESB Networks Ltd. as the Distribution System Operator.

<sup>2</sup> Demand customers will however pay 50% of the LCC connection charge unless they request an alternative connection method..

Please note that in the event of any inconsistencies between this paper and any transmission or distribution connection agreement, the connection agreement would take precedence.

EirGrid plc, the Transmission System Operator, will be referred to as TSO throughout the document. ESB Networks Ltd., the Distribution System Operator, will be referred to as DSO throughout the document.

A list of relevant published documents is contained in Appendix 5 to this paper.

## 2 Connection Method Principles

### 2.1 *Least Cost Connection Method and basis for charging*

Under the GPA the **Customer**<sup>3</sup> or **Subgroup**<sup>4</sup> will be charged based on the **Least Cost** connection method, except in the circumstance where the Customer or Subgroup requests an alternative connection method. This connection method will be the least cost to the Subgroup as a whole, and will be based on the assumption that all subgroup members will proceed to connection.

Previously the term Least Cost Technically Acceptable (LCTA) connection method was used to describe the basis of the connection charge for connections that had transmission and/or distribution assets as part of their connection. However it is appropriate to highlight the different connection charging boundaries at transmission and distribution and the subsequent affect on what connection methods may or may not be termed technically acceptable.

For distribution applicants that only require distribution assets for connection (i.e. there are no shallow transmission assets) both “shallow” distribution connection assets and “deep” system reinforcements on the distribution system which are driven by those applicants are charged for through the connection charge.

For all applicants at transmission, and for those applicants at distribution who have shallow transmission assets, only “shallow” transmission assets - as defined by application of the transmission connection charging boundary rules<sup>5</sup> - are charged for through the connection charge. The application of these pricing rules requires certain simplifying assumptions to be made regarding the operation of the transmission system, particularly that capacity availability will be considered in an intact network situation (i.e. ignoring all other flows on the transmission system) and without

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<sup>3</sup> A party who has entered into, or applied to enter into, a contract for connection to the transmission or distribution system at either the entry or exit point.

<sup>4</sup> A number of Customers in the same geographic location who will share a connection method or connection assets. For the purposes of this paper Customer may mean Customer and/or subgroup depending on the context.

<sup>5</sup> For detailed information on the connection charging boundary between “shallow” and “deep” assets read EirGrid’s Transmission Connection Charging Methodology Statement, available at [www.eirgrid.com](http://www.eirgrid.com).

consideration of system contingencies. Thus depending on where the boundary is between “shallow” and “deep” transmission assets after application of the transmission charging boundary rules the least cost shallow transmission connection method may or may not be technically acceptable. Thus the use of the term Least Cost Technically Acceptable Connection Method Charge for transmission assets can be misleading.

In the case of transmission assets, therefore, it is appropriate to use a slightly varying term. More accurately the term should be Least Cost Chargeable (LCC) connection method charge. For distribution applicants, whose connection does not require shallow transmission assets, the existing term Least Cost Technically Acceptable (LCTA) connection method charge is accurate.

Least Cost Connection Method	
Least Cost Technically Acceptable (LCTA) connection method – applies to DSO applicants with shallow & deep distribution assets (i.e. no shallow transmission assets).	Least Cost Chargeable (LCC) connection method – applies to all TSO applicants and those DSO applicants for whom shallow transmission assets form part of their connection method. This connection method may not be technically acceptable from a transmission planning perspective, this would depend on where the boundary is between “shallow” and “deep” transmission assets after application of the transmission charging boundary rules.

**Table 1 Least Cost Connection Method terminology**

For detailed information on the transmission connection charging boundary between “shallow” and “deep” assets read EirGrid’s Transmission Connection Charging Methodology Statement, available at [www.eirgrid.com](http://www.eirgrid.com).

Briefly however, after applying the transmission connection charging boundary rules the connection method, in an intact network situation:

- must be capable of accommodating the MEC and MIC of a Customer's facility; and
- must not result in a breach of the thermal capacity limits, or a breach of other applicable network standards, of any part of the system

In relation to the LCTA connection method, for connections which require only distribution works, the connection method – under normal feeding arrangements (i.e. an intact network situation), or standby feeding arrangements (due to plant outages) will be considered to be technically acceptable if it is :

- capable of accommodating the MEC and MIC of a Customer's facility
- compliant with Planning Standards
- in compliance with Distribution Code
- in compliance with all technical policies prevailing at the time of offer issue.

In addition all equipment installed as part of the connection method must adhere to the minimum standard rating for use on the system, as determined by the system operators.

For the avoidance of doubt, the Subgroup will pay for the LCC/LCTA<sup>6</sup> connection method prevailing at the time of offer issue. If system standards change in the period between offer issue and asset construction, any incremental cost will be borne by the Use of System (UoS) customer.

In addition the allocation of charges amongst the group will reflect the allocation of charges appropriate to the LCC/LCTA connection method (except – as above – where the subgroup request an alternative connection method.) Section 3 sets out in more detail the basis for the sharing of costs.

In deriving the least cost solution the System Operators will have regard current commercial policy and to the following costs:

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<sup>6</sup> Where both transmission and distribution connection assets are required the charge will be the least cost taking account of works on both the Transmission and Distribution systems

- The capital cost of equipment<sup>7</sup> required to connect the Customer<sup>8</sup>, or the Subgroup, to the system.
- The cost of cable civil works (ducting trenching and re-instatement) where these works are carried out by the Customer.<sup>9</sup>
- The cost of the Customer transformer where this is a factor in the least cost calculation (i.e. where the connection voltage is a factor in determining the least cost connection.)
- DSO will take account of losses incurred, in determining the shared assets to be installed.
- TSO includes an estimate for civil costs (e.g. station civil costs) and land costs<sup>10</sup>
- The LCC/LCTA will not include any pass through costs which cannot be determined at the time of offer issuance.

## ***2.2 Actual Build***

The **Actual Build** method is the connection method which is actually built to connect the party. This can be any one of the LCC/LCTA, or a customer or System Operator preferred method.

## ***2.3 The System Operator Preferred Connection method***

While the basis for charging will typically be the LCC/LCTA connection method, the System Operator may specify a connection method different from the least cost connection method as being a more appropriate connection method for an individual sub-group. This is referred to as the **System Operator's Preferred Connection Method** and will take into account wider system development, the costs of associated

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<sup>7</sup> For the purposes of determining the least cost Connection Method the capital cost will assume a non-contestable connection and therefore will be based on current and approved Standard Charges

<sup>8</sup> For distribution connections the capital cost will include distribution deep re-enforcements

<sup>9</sup> These works are not chargeable by the System Operator to the customer as they are undertaken by the customer

<sup>10</sup> In comparing transmission and distribution connections, where the issue of charging for civil and land costs is an issue, then the calculation of LCTA shall be modified in order to ensure the comparison is on a 'like for like' basis.



transmission system reinforcements, the possibility of future connections at a subsequent date, and an overall prudent medium term approach to system planning. In the first instance any additional cost will be recovered through the UoS charges rather than from the connecting parties, subject to usual regulatory scrutiny with respect to the appropriateness and efficiency of the investments. Any future connections to the assets built will, however, be charged on the basis of the actual build.

Appendix 1 sets out the basis for the calculation of the connection charge where the connection method is System Operator Preferred.

#### ***2.4 Relationship between desktop connection method and actual build***

The System Operator Preferred Connection methods, and LCC/LCTA connection methods, as outlined in the connection agreement, are desktop studies<sup>11</sup> and may not significantly correspond to the actual build, which will reflect the outcome of the planning process, ground conditions and local and environmental factors.

In seeking to construct system assets, the System Operator will seek to consent the desktop connection method, in accordance with the requirements of the Planning and Development Act (2000), and will use experience and best judgement, in consultation with consultants and the appropriate planning authorities, to determine the most appropriate actual build<sup>12</sup>. The same process is followed regardless of a line being required for system reinforcement purposes or as a Customer connection asset.

It should be noted that the contractual connection methods are based on desktop studies with limited consideration of the local environmental and ground conditions. These connection methods represent the starting point for determining the final connection method constructed. Also for certain transmission lines, the planning process requires a number of routes to be specified. The likelihood, therefore, of the

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<sup>11</sup> Although these connection methods are primarily determined via desktop studies; any known local and/or environmental issues will be taken into account during these studies.

<sup>12</sup> This can vary by route or technology.

exact desktop system operator connection method or LCC connection method route being constructed is low.

The actual build solution is site specific, influenced by the planning process and also subject to the application of prudent utility practice. The actual build solution may involve longer or alternative routes, cabled or part cabled connection. In the event that the Transmission System Operator elects to build a connection which differs from LCC and cable is the outturn technology for the circuit then it is proposed to cap the contribution from the customer at the equivalent cost of cabling the LCC.

In the case of distribution connections, as it is less likely that a SO preferred connection method will be proposed, in the event that the Distribution System Operator elects to build a connection which differs from LCTA, and cable is the outturn technology for the circuit then it is proposed to cap the contribution from the customer at the equivalent cost for the LCTA as an overhead build.

If a Customer requests a more expensive technology than the LCC connection method solution at any stage in the connection process, the associated incremental cost will be fully to the account of the Customer.

Per the Connection Agreement route length for the LCC is a pass-through cost. It is proposed that if the SO elects to build other than the LCC then any costs resulting from a longer route length would be to the account of the UoS Customer.

## ***2.5 Stranded assets***

Where a Customer seeks to modify their connection method such that they are no longer sharing assets in the same manner as set out in the connection offers to the group, the applicant will remain liable for the cost of the shared assets (**Stranded Asset Cost**) which would otherwise have to be re-distributed amongst the group or be covered by the end user. For the avoidance of doubt, a Customer is only liable for

Stranded Asset Cost in respect of new shared assets being built, and is not liable for Stranded Asset Costs in respect of Existing Assets.<sup>13</sup>

### 3 Connection Charging Principles

As stated previously, connection charges are calculated based on the LCC/LCTA connection method, except in circumstances where the Customer has requested an alternative solution. Connection charges reflect the cost of constructing, installing and maintaining the connection assets, and of refunding any parties who have paid for Existing Assets. Please note that any additional costs associated with infrastructure not required for the connection and installed for use solely by the System Operator or for third parties, e.g. additional fibres, additional ducts, etc., will not form part of the connection charge.

Charges comprise a capital element to cover the construction and installation of the asset, and a revenue element to cover ongoing maintenance of the assets (Operation and Maintenance Charges). Developers may also be liable for other charges such as a decommissioning and reinstatement charge<sup>14</sup> – in the case of a transmission connection.

The capital element of the charge is made up of different types of connection assets as follows:

1. **Dedicated Connection Assets** – assets that are used exclusively by one user

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<sup>13</sup> Assets that are built and paid for (or in the process of being built or should already have been built) by either previous connections or by the UoS customer.

<sup>14</sup> This covers the cost of decommissioning and reinstating the relevant equipment associated with a transmission connection, in the event that the connection agreement is terminated. In the event that the customer does not pay the Decommissioning and Reinstatement charges, and TSO is unable to recover them, these costs are recoverable and underwritten by TUoS.

2. **Shared Connection Assets**<sup>15</sup> –assets that are not yet built and will be shared by a number of users in the subgroup
  
3. **Allocated Equipment** (transmission only) – equipment relating to Existing Assets.

Where any assets required for the connection of a Customer have been previously identified by the System Operators as being required for system development purposes, and have received financial approval to proceed, the Customer will only be charged the cost of building that asset at an earlier stage. In addition where the works required to connect the generators are such that it removes the need for other works previously identified (and having received financial approval) by the System Operators, the Customer will be credited with the cost of this ‘avoided work’ and their connection charge reduced accordingly.

Charges for existing connection assets – whether paid for by customers or the system – should never be such as to drive non-optimum system development. In such cases, therefore, charges for existing assets, and rebates to existing customers (or the UoS customer) will be reduced accordingly.

As outlined in the Commission Direction (CER/05/049) of April 2005, the connection charging policy under the GPA shall include the following principles:

1. Generators will be charged 100% of the cost of providing the Dedicated Connection Asset (excepting where the System Operator has determined that the asset should be oversized to accommodate future development);
2. Charges for connection to the Shared Connection Assets<sup>16</sup> shall be based on a per MW basis in accordance with the formulae in Figure 1.

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<sup>15</sup> For distribution connections any refunds to previous generators/demand customers are included with shared assets, but separately identified

<sup>16</sup> Customers will typically be charged on the basis of actual assets shared including any standby facility afforded by assets not normally used. An exception to this rule will apply, however in the event that there is no technical or cost advantage to a particular feeding arrangement, and charging based on actual assets will unfairly penalise a developer.

<p><b><u>Transmission Connections:</u></b> <math>P_T * X * (Z/W)</math></p> <p><b><u>Distribution Connections:</u></b> <math>[(P_T * X) * (Z/W)] + [(P_D * Y) * (Z/V)]</math></p> <p>Where:</p> <p>X = Total cost (LCC/LCTA for the subgroup) of providing the associated transmission works of the Shared Network including remote end station allocated charges</p> <p>Y = Total cost of providing the associated distribution works of the Shared Network</p> <p>Z = MEC (in MW) of the specific generating plant</p> <p>W = Total MEC (in MW) of the Generator Applications in that Subgroup</p> <p>V = Total MEC (in MW) of the DSO Generator Applications in that Subgroup*</p> <p>P<sub>T</sub> = Transmission Probability Factor = 1 for all Gates to date</p> <p>P<sub>D</sub> = Distribution Probability Factor = 1 for all Gates to date</p>
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**Figure 1: TSO/DSO Connection Charging Formulae for Shared Connection Assets**

### ***3.1 Connection to Transmission System***

The capital charge for connection to the transmission system is determined on a “shallow” basis<sup>17</sup>.

#### **3.1.1 Payment for existing system assets**

In the case where a Customer, by connection to existing station, shares assets with the existing transmission system, the connecting Customer pays for the bays and protection etc. associated with its connection and a proportion of the **Station Common Costs**<sup>18</sup>. Station Common Costs will be levied on a per bay basis. The Customer will be charged one set of station common costs for each bay required for connection. For the avoidance of doubt, in the event that a number of Customers in a Subgroup are connecting via the same transmission bay, the Station Common Costs associated with the bay are apportioned between the members of the subgroup on a per MW basis.

<sup>17</sup> For detailed information on the connection charging boundary read EirGrid’s Transmission Connection Charging Methodology Statement, available at [www.eirgrid.com](http://www.eirgrid.com).

<sup>18</sup> Costs associated with the station to which the user is connected, typically busbars, couplers, site and civil costs, control buildings etc.

In some cases additional station works are required in order for the station to comply with transmission standards following connection of the Customer. An example might be the need for a coupler or double busbar. In such a situation the Customer will pay for their share of the Existing Assets on the following basis:

- if connection is into an existing transmission station, the cost of additional works required to comply with transmission standards (due to the increased station size) are deemed to be covered by the Station Common Cost charge.
- If connection is via a station financed by previous parties, the Customer will pay the greater of:
  - i. A per MW share of the station cost (including the cost of additional equipment); or
  - ii. 100% of the cost of the additional equipment.

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In this instance, as set out in further detail in section 4, existing Customers will only be eligible for a refund after the cost of the new equipment is covered.

The Customer will, of course, pay for all other shallow connection works on the appropriate basis, including Dedicated Assets required in the existing station.

Examples of how the connection charge would be applied and the associated impact on rebates are outlined in Appendix 2.

The charging structure, in respect of transmission, is conducted in accordance with Commission approved connection charging policy as outlined by the Commission on the 16th October 2000, in its Direction on the boundary between Connection and **Transmission Use of System (TUoS)** assets.

### 3.2 *Connection to Distribution System*

The charges for connection to the distribution system are comprised of costs associated with both dedicated assets and shared assets<sup>19</sup> (as set out in Figure 1 in the introduction to this section) including **Distribution Reinforcement**<sup>20</sup> works, which enable generators to export their full MEC. Charges are calculated using the current version of the standard charges – the basis for which are set out in the Commission Direction (CER/05/090) of June 2005 and subsequent directions. As depicted in Figure 1 shared assets are apportioned on a per MW basis.

Distribution connected generators are typically not charged for use of existing system assets. The following exceptions (not intended as an exhaustive list) apply:

1. These have been paid for by previous connections (generation or demand)
2. These have been paid for by the **Distribution Use of System (DUoS)** customer as a result of
  1. a GPA offer not being taken up, or
  2. full payment not being recovered<sup>21</sup> or
  3. the connection method taking account of future generation
3. These assets have been paid for by the GUDP fund – see Section 3.3 below

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### 3.3 *Connection to assets funded by the GUDP fund*

The **Grid Upgrade Development Plan (GUDP)** is a European Union funded programme, implemented by the Irish Government in 2003 to encourage and fund the development of electricity assets required to connect renewable generation. All applicants connecting to the transmission or distribution System using GUDP funded

<sup>19</sup> Shared with other members of the sub-group.

<sup>20</sup> Distribution re-inforcement works are works required to upgrade system assets in order to allow generators export their required MEC.

<sup>21</sup> For example where a developer has not progressed to energisation.

assets will be charged based on the pricing principals that apply under GUDP. The charging rules for this fund are as follows:

- **Distribution assets.-**
  - charge to be calculated as follows:  
 $((\text{Cost of asset}) * (\text{MEC of connecting generator})) / 60\text{MW}$
- **Transmission assets.-**
  - charge to be calculated as follows:  
 $((\text{Cost of asset}) * (\text{MEC of connecting generator})) / 70\text{MW}$

Infrastructure funded by the GUDP fund, and to which the above charging rules will apply, are as set out in Appendix 3.

### ***3.4 Contestability***

Parties connecting directly to the transmission system and generators connecting to the distribution system have the right to construct, or arrange to have constructed their shallow connection. The rules and principles under which contestability operates are as set out in the System Operators respective policy papers on this issue as amended from time to time.

#### **3.4.1 Charging for contestable connections**

The parties undertaking contestable connection works will be responsible for the cost of oversight etc. required by the System Operator to ensure the connection is built according to the required specifications. In addition, the parties will be liable for the cost of any non-contestable works required for their connection.

Should the System Operator require a connection method other than the LCC/LCTA method to be constructed (the System Operation Preferred Connection Method) the parties must, of course, construct the method specified by the System Operator. However, the parties will receive a capital contribution to cover the incremental cost of the System Operator's chosen connection. This contribution will be paid following



energisation of the assets built, and handover of said assets to the relevant System Operator, and will be based on the System Operators standard charges.

Under certain circumstances, the ownership of the contestably built assets will be transferred to the System Operator. In such circumstances and in line with general charging policy for generator connections, the transfer will be for a nominal fee.

### 3.5 Bonds

A party seeking to connect to the transmission and distribution systems must provide security in the form of a number of bonds which are designed to protect other users of the system.

#### 3.5.1 Capacity Bond<sup>22</sup>

The **Capacity Bond** is designed to prevent the hoarding of transmission capacity and also – in the event that a bond is drawn down – contribute towards the cost of transmission deep re-enforcements which may have commenced. The requirements with regard to this bond are as set out in CER decision paper cer\09\138. However the basic principles are as follows:

1. Capacity bonds will not be required for projects with an MEC of less than or equal to 5MW or as directed by CER
2. The value of the capacity bond to be based on €25,000/MW of MEC
3. For all generators connecting to the Distribution System and for renewable generators connecting to the Transmission System the bond to be posted as follows:
  - The earlier date of 2 years post Planning Permission Date, or at the 2<sup>nd</sup> last payment – prior to commissioning and energisation – for Distribution connected applicants
  - The earlier date of 2 years post Consents Issue Date or no less than one month prior to energisation for transmission connected applicants.<sup>23</sup>

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<sup>22</sup> Capacity bond policy will be set out in detail in the Connection Policy Paper to be published shortly. Once the Connection Charges Paper is approved, this section will be removed from the Charging and Rebating Paper.

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4. For conventional generators and interconnectors<sup>24</sup> connecting to the Transmission System, bond to be posted at offer acceptance stage. The value of the bond to be €10,000/MW of MEC

The process for drawing down on the bond is as set out in detail in CER decision paper CER\09\138.

### **3.5.2 Connection Charges Bond**

A connection charges bond is typically required only for transmission connected applicants. The connection charges bond must be posted by the Consents Issue Date (CID)<sup>25</sup>. This bond will cover any costs incurred during construction of the shallow connection assets which are not covered under the payments made by the applicant. Part of the bond will be drawn down should the applicant not proceed to connect, in order to cover any cost outlays by the System Operator.

The GPA connection policy paper will outline all current bonding requirements.

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<sup>23</sup> Energisation will not take place in the event that a bond is required but has not been put in place

<sup>24</sup> For interconnectors the value of the bond will be calculated based on export rather than import capacity

<sup>25</sup> The date on which both the System Operator and the customer have obtained the consents relating to the connection works necessary to allow construction works to begin.

### **3.6 Basis of Offers and Payment Schedules**

#### **3.6.1 Transmission**

The connection charge is calculated based on standard transmission charges as approved by the CER and outlined in CER/09/077.<sup>26</sup> The connection works and the associated charges are set out in the connection offer. These charges are based on a number of assumptions set out in the offer letter, if any of those assumptions fails then the entire offer is open to be revisited. The fixed charges are adjusted for inflation on an annual basis.

As per CER/09/077, asset cost categories not included in the Standard Transmission Charges and Indicative Timelines paper will be provided by EirGrid on a case by case basis. Such cost categories are non-standard and subject to variation and therefore not amenable to the provision of a reasonably accurate average.

**Pass Through Costs** are those charges that are not directly controlled by the TSO and cannot be directly recovered by the Transmission Asset Owner (TAO). These costs are project specific and are passed directly to the customer. Any change in

- the cost of consents,
- the timing of the connection,
- project management fees<sup>27</sup> and/or
- the method of connection

could give rise to a change in the Pass Through Costs, which in turn could give rise to a change in the connection charge. Estimated Pass Through Costs are outlined in the TSO's offer letter.

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<sup>26</sup> Standard Transmission Charges and Indicative Timelines, available at [www.cer.ie](http://www.cer.ie).

<sup>27</sup> Associated with contestable connections only.

### 3.6.2 Schedule of payments – Transmission

The payment schedule is offer specific and related to the cash flow associated with providing the shallow connection assets. These payments are payable in advance to ensure the TSO/ TAO remain in a cash positive position thus minimising the risk to the TUoS customer.

Where consents are required, the second and subsequent payments are scheduled to ensure alignment with the actual work being performed. In all cases the full connection charge will be payable before the connection works are completed.

### 3.6.3 Distribution

DSO connection offer charges are generally determined using the CER approved standard charges. They are firm costs with the exception of pass through costs, and volume changes. Pass through charges are as outlined below:

Item	Estimate to be provided at Offer stage	Limitations on estimate
Civil works – stations and cables	Yes	An estimate of the civil works costs associated with the station elements assuming ‘normal site conditions’ could be provided. However – under certain conditions – developers can undertake civil works for both stations and cables.
Road Opening Licences and associated costs where cable works are undertaken by ESB Networks Ltd.	Yes	Road opening licenses and associated costs <sup>28</sup> cost vary between local authorities and also vary from time to time. While ESNB will endeavour to provide a best estimate, its accuracy will vary.
110kV cable – where length is >1km	Yes	Best estimate that developers should use is the standard charge approved by CER for 1km 110kV cable by the quoted volume.
Site purchase costs	No	Site dimensions to be provided.

<sup>28</sup> In some cases, Local Authorities request a bond and/or long-term re-instatement payments

## Joint TSO/DSO Group Processing Approach Charging and Rebating Principles v2.0

Need for temporary transformer	Yes	Will be firm.
TSO Pass through costs	Yes	As provided by TSO.
Wayleaves and Consents outside that included in offer	No	
Forestry compensation	Yes	To be based on current agreements with Coillte.
Access for material delivery where terrain is bad (e.g. helicopter drops)	No	
Planning permission changes	No	
Costs due to lock-out	No	
Volume changes	No	

Pass through costs are charged based on estimates where available, and otherwise as they arise. All pass through costs are reconciled and fully payable at final stage payment. Where costs have not been finalised at this point any over or under-recovery will be to the account of the end user.

### 3.6.4 Schedule of payments - Distribution

#### *Non-Contestable Connections*

The distribution payment schedule for non-contestable connections is as follows:

**First Stage Payment** An initial non-refundable payment on acceptance of the connection agreement. This payment will be equal to €10,000/MW subject to a minimum payment of 10%, and a maximum payment of 50%, of the **Capital Contribution**<sup>29</sup>.

**Second stage payment** to be such that total payment will be 65% of the Capital Contribution and a minimum of 65% of any known estimated Pass Through Costs. Payment must be made within thirty business days of request for payment, and before construction of the **Company's Connection Works**<sup>30</sup> begin.

**Third Stage Payment** to be such that total payment will be 90% of the Capital Contribution and a minimum of 90% of any known estimated Pass Through Costs<sup>2</sup>. Payment must be made within thirty business days of request for payment, and one calendar month before the **Connection Agreement Effective Date**<sup>31</sup>.

**Final Stage payment** covers the balance of the total Capital Contribution (including any outstanding Pass Through Costs,) The final stage payment will also include the full amount of charges for Existing Assets, which will result in refunds to Existing Customers, the DUoS customer or the GUDP fund The final stage payment is due when applying for data validation and before export data is sent by the DSO to **Single Electricity Market Operator (SEMO)** for payment.

#### *Contestable Connections*

The exact payment schedule will be linked to milestones for the contestable connection. However the First Stage Payment is as follows:

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<sup>29</sup> As defined in the DSO connection agreement.

<sup>30</sup> As defined in the DSO connection agreement.

<sup>31</sup> As defined in the DSO connection agreement.

**First Stage Payment** will be the greater of 10% of the Capital Contribution (including any estimated pass through costs at date of offer issue), or €10,000/MW

### ***3.7 Annual Charges***

In addition to connection charges, generators are liable for a number of annual charges as follows:

#### **3.7.1 Operations and Maintenance Charges (O&M)**

Both Transmission and Distribution connected generators are liable for these charges which incorporate rates, maintenance, operations and indirect overheads attributable to maintaining the asset. The annual charge covers the average annual cost the System Operators expect will be incurred over the life of the connection agreement, and is payable for the period of connection.

Where more than one customer is connected at a site, the O&M charge for the assets will be apportioned on the same basis as the capital component (i.e. on a per MW basis). In addition where a Customer is liable for Stranded Asset Costs, (as set out in Section 2.4), the Customer is also liable for a share of O&M on those assets.

Distribution connected generators who have driven the need for transmission shallow assets and been charged for their construction, are liable for O&M charges on these transmission shallow assets. To date these have not been charged. O&M charges for transmission assets are currently being revised and will be consulted on by CER prior to implementation by the TSO.

#### **3.7.2 Transmission Use of System charges (TUoS).**

All transmission and distribution connected generators are liable for generation TUoS charges on their export. For distribution connected generators, only those with an MEC  $\geq$  10MW are charged at present for their use of the transmission system.

However this threshold may be revised from time to time<sup>32</sup>. In addition all transmission and distribution connected generators are liable for demand TUoS charges, in respect of their **Maximum Import Capacity (MIC)** and any applicable energy charges (MWh charges).

### **3.7.3 Distribution Use of System Charges (DUoS).**

All Distribution connected generators' suppliers are liable for DUoS charges for their MIC. The appropriate DUoS group depends on the actual connection voltage, but is as set out in the current version of the DUoS tariff statement. Distribution connected generators are not liable for DUoS charges on their **Maximum Export Capacity (MEC)**.

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<sup>32</sup> Any change to this threshold will be captured in the TSO's Statement of Charges document, updated annually, and will be advised in writing to all affected customers with a current TUoS Agreement.



## 4 Rebating Principles

The timeline for which rebates will be offered to Customers who have paid for connection assets will be as follows:

- Transmission assets – rebates will be offered for 50 years (regulatory life of transmission assets). This rebate timeline has increased from 10 years and will apply to all generators who funded transmission assets since market liberalisation<sup>33</sup>
- Distribution assets – rebates will be offered for 45 years (regulatory life of distribution assets). This rebate timeline will apply to all generators who funded distribution assets since the beginning of Gate 1 (2005)<sup>34</sup>

In order to accommodate this extension in the timeline for rebating of assets the charging and rebate policies have been simplified as follows:

- Charging and rebating for Existing Assets will always be on the basis of actual build as set out in Section 2.3. Rebates to existing Customers will be based upon the connection charge<sup>35</sup> received from, discounted (from date of energisation of the existing Customers) in accordance with the depreciation profile.

Further principles of rebating are set out below.

### 4.1 General principles

1. A shared network charge / refund may apply in cases where a new Customer makes use of the connection assets of an existing Customer.

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<sup>33</sup> 19<sup>th</sup> February 2000.

<sup>34</sup> Rebates to demand customer who have financed distribution assets will still be issued for up to 5 years only. This is to reflect the fact that DSO has a large number of demand customers and to extend the rebate timeline for these beyond 5 years would impose a costly administration burden. This cost is deemed to be disproportionate to the benefits which would accrue.

<sup>35</sup> Modern Equivalent Asset Value. This is defined as the standard charge applicable to a given asset at the time the rebate is being processed.

2. The shared network charge is paid by the new Customer who directly benefits from the connection. The charge is apportioned on a per MW basis in the same way as if the parties utilising the assets were being processed in the same Gate. The refund is paid to either
  - i. the customer who executed the connection agreement for the original connection and financed the connection works; or
  - ii. The **Regulated Asset Base (RAB)**, where the refund is for assets paid for by the UoS customer.
3. Parties are only eligible for a refund where a new Customer is connected to, and energised at, the assets for which the existing Customer(s) has paid.<sup>36</sup>
4. Refunds are associated with the connection agreement. Therefore where there has been a Change of Legal Entity on the connection agreement, the new legal entity is eligible for the refund, and the previous customer has no further entitlement. (References to existing Customers below should be interpreted accordingly.)
5. The value of the shared network refund for which existing Customers are eligible depends on the total contribution charged to and recovered from the new Customer. Where an existing Customer paid for the existing or contracted asset, the contribution received from the new Customer is apportioned based on the percentage paid by the existing Customer towards the assets.<sup>37</sup>
6. Depreciation is calculated on a straight line basis, from date of energisation, over 45 years for distribution assets and over 50 years for transmission assets.
7. Where plant retired as part of an upgrade paid for by a generator can subsequently be reused on the distribution or transmission system then a retirement credit may apply (see section 4.4 for details of eligibility).

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<sup>36</sup> For the avoidance of doubt in the event that a new applicant – whose quoted Capital Contribution included an element for sharing an existing or contracted asset – does not accept their offer, or requests a modification which results in them not sharing the asset, neither the UoS customer, nor the party requesting a modification will be liable for any cost associated with the existing assets.

<sup>37</sup> Where connections were made over different time periods the total contribution of each customer should be calculated in current money terms and the % calculated on this basis.

8. Where a connection agreement is terminated, the original connecting party, or any party to whom they had transferred the connection agreement pre-termination, has no longer any rights to refunds.
9. In the case of distribution connections, refunds to an existing Customer will be made upon energisation and final payment by the new Customer. For transmission connected customers refunds to the existing customer will be made following energisation of the new Customer.
10. Total refunds paid should never exceed the amounts originally paid by an existing Customer, indexed linked to present day values.
11. Refunds will be paid to all parties (including the UoS customer) who originally paid for the assets, regardless of whether the parties are physically connected to those assets. The exception to this is as set out in point 7 above.
12. Where an asset was funded by the GUDP fund, no rebates will apply to generators connected to that asset, but rather any payments received will go to the GUDP fund. (Infrastructure funded by the GUDP fund is as set out in Appendix 3).
13. Any rebate payments, for system development reasons, made by a System Operator to an existing customer will be added to the RAB.
14. A hierarchy for rebates is set out in Section 4.3.

#### ***4.2 Charging / refund process***

Refunds to customers who financed the construction of connection assets to which a new Customer is connecting will be calculated and administered on the following basis.

#### 4.2.1 Items to be included for rebate

The following costs will be considered eligible for inclusion in rebate calculation:

1. All elements of the connection charge as passed through from the System Operator to a connecting generator<sup>38</sup>
2. For distribution works, costs incurred by the Customer as per the following tables:

Item for rebate	Documentation required
<b>Civil works costs associated with cable laying</b>	<b>As built drawing showing cable route and lengths; refunds are in accordance with the table of civil costs below.</b>
<b>Civil works Costs associated with station infrastructure</b>	<b>Refunds are in accordance with the table of civil costs below.</b>
<b>Road opening licenses and associated costs</b>	<b>Invoices from Local Authority</b>
<b>Requirements imposed by Local Authorities</b>	<b>Evidence of requirement from Local Authority and invoices</b>
<b>Cable Easements</b>	<b>Evidence of legal documentation and invoiced costs</b>
<b>Site purchase</b>	<b>Evidence of legal documentation and invoiced costs</b>
<b>Bridge crossings</b>	<b>Invoiced costs</b>
<b>River crossings</b>	<b>Invoiced costs</b>

Table 2

<sup>38</sup> As previously set out (5.1), where the connection method of a generator has changed, they will be eligible for a refund on the costs paid for their new connection

Item		2008 Approved cost	
Civil Works for MV cable		<b>€50,000/km<sup>36</sup></b>	
Civil Works for 38kV or 110kV cable		<b>€144,000/km<sup>36</sup></b>	
Item		2010 Approved Cost	
Civil works for a typical outdoor 38kV station		<b>€400,000<sup>39</sup></b>	
Civil works for a typical outdoor 110kV station		<b>€1,000,000<sup>36</sup></b>	

Table 3

In relation to costs incurred by the developer, specifically in relation to Table 2 please note that in order for a cost to be eligible for a refund, all required documentation (as outlined above in Table 2) is to be submitted to the DSO within 30 business days of the Connection Agreement Effective Date of the development.

This documentation will be kept on file by the DSO for the period for which the customer is eligible for a refund. All such cost data will then be used in the calculation of charges to a new Customer and refunds due to the existing Customer on the following basis:

- Charge to new Customer to be based on the historical cost, index linked to present day and depreciated over 45 years.
- Refund to existing Customer to be also based on above charge, although subject to an administration fee.

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<sup>39</sup> These costs are for the purposes of refund only. Where DSO undertakes civil works the exact cost will vary from job to job and the cost will be a Pass Through Cost.

#### **4.2.2 Demand connections to assets paid for by generation Customers**

Charging and rebating policy differs between TSO and DSO in relation to demand customers connecting to assets paid for by generators. This is due to the differences in the predominantly meshed transmission system in comparison to the predominantly radial distribution system.

##### **4.2.2.1 Transmission connected customers:**

As outlined above, the TSO does not distinguish between generation and demand in terms of charging and rebating policy. The share of a connection asset will be determined on a per MW basis, regardless of whether the connecting or connected parties are generation or demand facilities.

Therefore, regardless of the type of facility sharing connection assets, the share of costs will be calculated on the same basis<sup>40</sup>:

If the TSO connects an additional transmission system line to an existing looped station (or a station consisting of more than two system lines built to connect a user to the transmission system) within fifty years of connection then the circuits connecting the transmission station to the network will be deemed Use of System assets and the existing Customer(s) at that station will be eligible to receive a rebate on assets previously defined as connection assets. The rebate will be based on a per bay share of the MEAV of the station, depreciated from the date of energisation of the pre-connected Customer(s). However, the rebate from the system should never be so large as to drive non-optimum system development.

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<sup>40</sup> Although demand customers only pay 50% of their connection charge, the remaining 50% of their per MW share will be paid by the TUoS customer.

#### 4.2.2.2 Distribution connected customers:

Depending on the category of asset that connects to an existing Customer's asset, a demand customer, the DSO or a generator, there are two methods for calculating the per MW (MIC or MEC) share of the asset. As the existing Customer is eligible for a share of the connecting charge of the new Customer, the rebate will vary accordingly.

- In the case of a new generator connection to an Existing Asset paid for by a generator, the charge to the new Customer is based on the ratio of the MEC levels since both parties are sharing the same asset on the same basis.
- In the case of a demand or a DSO connection whose normal feeding arrangement is to an Existing Asset paid for by a generator, the charge to the new Customer (or to the UoS customer) is based on the ratio of the connecting MIC level <sup>41</sup>to the ultimate capacity of the asset. This process is adopted for the following reasons:
  - It is consistent with charging principles for load customers.
  - As the distribution system is a radial system the new load connection does not limit the future amount of generation that can be connected to the asset. On the contrary, addition of load will allow additional generation to be accommodated.
  - This approach facilitates the optimum development of the system.
  - Adopting this approach is more likely to lead to generator assets being used for system reasons, and therefore generators are more likely to get a refund.

The following table sets out what the ultimate capacity of the main asset groups would be:

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<sup>41</sup> For DSO connections the MW share will be based on the average annual peak load normally fed from the asset over a 10 year period, assuming 0.95 power factor

DSO Assets	Ultimate Asset	Ultimate capacity
110kV OH line	200SCA	109MVA
110kV cable	630XLPE	93MVA
110kV/MV station	2x31.5MVA	56.7MVA
110kV/38kV station	2x63MVA	113.4MVA
38kV/MV station	2x15MVA	27MVA
38kV OH single pole line	150AAAC – X 8 construction	40.07MVA
38kV OH portal construction	300SCA – C8 construction	61.33MVA
MV OH line	3x150AAAC@20kV	21.85MVA
38kV cable	Minimum 630XLPE (however to be determined on a case by case)	51MVA
MV cable	400XLPE @20kV	20.22MVA

Table 4<sup>42</sup>

See Appendix 4 for examples of the above policy.

<sup>42</sup> Please note the capacities outlined in Table 4 reflect the thermal capacity of the lines and stations. The actual load or generation which can be connected via a specific asset will be subject to additional technical constraints for example voltage and losses



### **4.3 Order of refunds**

Where a Customer connects to a shared/dedicated asset, the order of rebates to other parties is as follows:

**DUoS/TUoS** - Where the TUoS/DUoS customer has incurred additional costs to facilitate the connection of future Customers or where the TUoS/DUoS customer has paid for development in the interests of longer term system planning, or where the TUoS/DUoS customer has picked up costs as result of offers issued not being accepted, etc, the TUoS/DUoS customer is rebated in the first instance<sup>43</sup>.

**GUDP Fund** - Where the GUDP fund has incurred costs to facilitate the connection of future customers the GUDP fund is rebated after the TUoS/DUoS customer.

**Connecting Party** - Where a party reduces their MEC after accepting an offer or a Party pays for the connection assets but does not actually use the connection.

**Others** - All other parties connected.

### **4.4 Other Credits which may apply**

Requests for transformer upgrades require removal of the existing transformers and their replacement by larger capacity transformers.

As per CER/08/077, where such transformers are re-used elsewhere on the system the generator is entitled to a refund. The refund will be paid only once the removed asset has been successfully commissioned in its new location.

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<sup>43</sup> In the event that the UoS customer – who, unlike other parties, has received no benefit for the investment made – was not entitled to rebates ahead of other parties, their investment would never be fully repaid.

The value of the refund will be calculated as follows:

MEAV at time transformer was removed\* (remaining life on RAB/regulatory asset life)\* CPI to present day. Any refund made in respect of such plant will be added to the RAB.

**Appendix 1 –Calculation of Connection Charge/Rebate where Connection Method is not LCC**

**EXAMPLE 1 – Transmission Example:**

**Table 2: Example 1**

	Dedicated Works (A)	Deep Works (B)	Overall System cost (A+B)	Allocated Charge (D)	Shallow Charge (A+D)
Option 1	<b>3</b>	<b>1</b>	<b>4</b>	1	4
Option 2	1	5	6	2	3
Option 3	<b>2</b>	4	6	<b>0</b>	<b>2</b>

In the table above there are three options for connecting a generator, or group of generators, to the transmission system, all of which have associated deep works, are technically acceptable and can be built. Option 1 is the connection method likely to be actually built as the overall cost on the system is the lowest when including necessary deep reinforcements - in other words it's the System Operator's Preferred Connection Method. However the generator(s) will only be charged for the LCC connection method - the dedicated assets charge (dedicated works) plus the associated allocated charge<sup>44</sup>, which in the case above is Option 3. Therefore the generator must pay €2 + €0 = €2, while the remaining connection cost will be recovered through the UoS charges.

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<sup>44</sup> The allocated charge is the charge apportioned to a generator for the sharing of any assets that are already in place or are being built e.g. sharing a connection asset, station common costs, etc

**EXAMPLE 2 – Distribution example**

*Gate N*

G1 = 5MVA

G2 = 10MVA

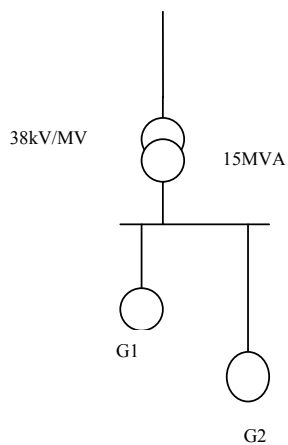


Figure 1

Figure 1 shows the Least Cost connection method for G1 and G2. The total station cost = €600,000.

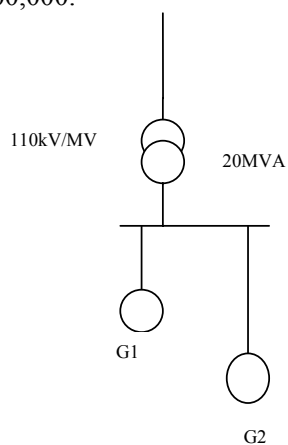


Figure 2

However DSO, for reasons of system development and in anticipation of connection of future generation, decides it is most appropriate to install a 110kV/MV station, with a 20MVA transformer (Figure 2). Under this scenario the total station cost is €1M<sup>45</sup>

The incremental distribution cost, therefore, to be paid for by the end-user is €400,000.<sup>46</sup>

However charge to G1 and G2 will be based on the Least Cost connection method which is the 38kV station

<b>Distribution Station Cost (Least Cost)</b>	<b>600000</b>
G1	200000
G2	400000

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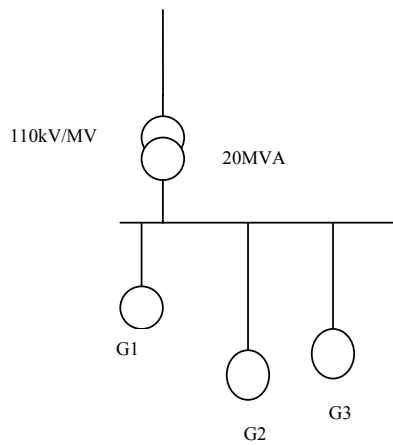
<sup>45</sup> Please note as Distribution deep reinforcements are typically chargeable to the generator, and therefore included in Least Cost calculations, it would be less usual for DSO to opt for a SO preferred method. However consideration of possible future connections may drive such an option.

<sup>46</sup> There would be additional costs on the transmission system also

**EXAMPLE 3 – Original connection based on SO preferred connection method – calculation of charge and refunds**

*Following on from example 2 above:*

*Gate N+1 – 5 years later*



G1 = 5MVA  
G2 = 10MVA  
G3 = 5MVA

The Least Cost connection method for all 3 generators is now the 110kV/MV station.

In this case, therefore, G3 will pay his share of actual build (€1M). i.e. G3 will pay €250,000.

As per hierarchy, only the SO is entitled to a refund (until such time as the original €400,000 is recovered)

**Appendix 2 – Charging for equipment, additional to the connection works, required in an existing transmission due to station size.**

The following examples outline how this equipment would be charged for, in the event that the station had been financed by previous connecting parties

**Example 1:** Applicant connecting into an existing 3 bay station, financed by 2 existing connected applicants. Due to the additional bay, a coupler is now required.

Per MW shares:

Existing Connection A: 40%

Existing Connection B: 30%

New Connection C: 30%

Cost of 110kV 3 bay station, connected by 2 km overhead line to a 5 bay transmission system station: €3,439,000.

Plus the cost of a coupler €730,000.

Total cost €4,169,000.

30% per MW share: €1,250,700

As the per MW share of the station (including coupler) exceeds the total cost of the coupler, C pays €1,250,700. The cost of the new coupler will be financed by this payment and the remaining money will be rebated to existing connecting parties in accordance with the normal rebating principles outlined in section 4 of this paper.

**Example 2:** Applicant connecting into an existing 5 bay looped station, financed by 3 existing connected applicants. Due to the additional bay, a coupler is now required for the station to remain technically acceptable.

Per MW shares:

Existing applicant A: 40%

Existing applicant B: 30%

Existing applicant C: 20%

New connection D: 10%

Cost of a 110kV 5 bay station, looped into an overhead line, located 1km from the station: €3,687,000.

Plus the cost of a coupler €730,000.

Total cost €4,417,000.

10% per MW share: €441,700

As the cost of the coupler exceeds the per MW share of the station (including coupler), D pays €730,000 (i.e. the total cost of the coupler). As there is no money

remaining from D's connection charge, the previous connecting applicants do not receive a rebate as a result of D utilising the connection assets for which they paid.



### **Appendix 3 – GUDP funding**

The Grid Upgrade Development Fund is a European fund which was made available to fund advance infrastructure required for the connection of renewables. The purpose of the fund was primarily to allow infrastructure to be built which was greater than that required for the applicants connecting at a point in time in order to take account of other likely developments in the area.

The following projects received funding from the GUDP fund :

Sorne Hill 110kV station

Kerry 110kV station

Corderry 110kV station

Generation connected to date to these projects have been charged on the following basis :

#### **Transmission assets :**

(Associated Charge for Infrastructure \*MEC of connecting generator in MW)/70MW

#### **Distribution assets :**

(Associated Charge for Infrastructure \*MEC of connecting generator in MW)/60MW

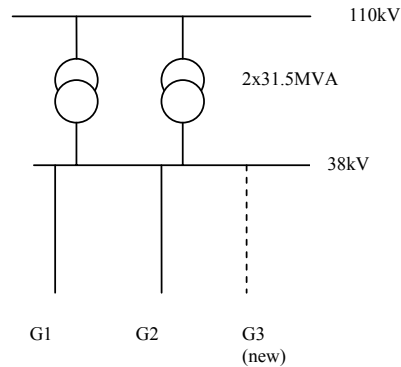
The same charging rules will apply to any generation connected to these assets in Gate 3.

Where infrastructure has been funded by the GUDP fund no refunds will apply to generators connected to that infrastructure.

**Appendix 4 – General Examples of calculation of charges and rebates for generators**

As set out in Section 4, customers may be due refunds where another generator, or load connects into assets paid for by the customer. Below are set out some examples of how this calculation would work.<sup>47</sup>

**Example 1 – Generator to be connected**



In the above example the cost of building the 110kV/38kV station – as originally charged to generators G1 and G2 - was €5M.

G1 is 15MW and G2 is 20MW, so they were charged as follows:

$$G1 \text{ charge} - (\text{€}5\text{M} \times 15) / 35 = \text{approx } \text{€}2.15\text{M}$$

$$G2 \text{ charge} - (\text{€}5\text{M} \times 20) / 35 = \text{approx } \text{€}2.85\text{M}.$$

Station was originally constructed and G1 and G2 energised 2 years ago.

G3 is also 20MW

Charge to G3 for sharing this asset is calculated based on the new per MW share as follows :

<sup>47</sup> For the purposes of simplifying the calculations charges quoted are not based on standard charges

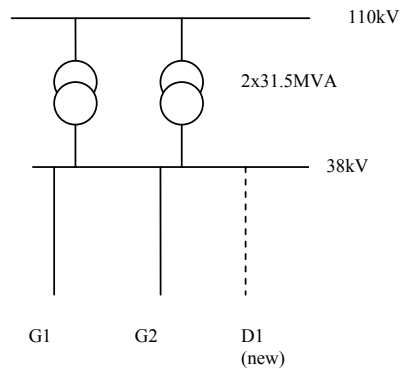
Cost attributable to G3 –  $(€5M*20)/55 = €1.8M$

This amount is then refunded to G1 and G2 on a pro-rata basis based on their MW.

Refund to G1 =  $(€1.8M*20)/35 = €1.03M$  – to be depreciated by 2 years = €0.99M

Refund to G2 =  $(€1.8M*15)/35 = €0.77$  – to be depreciated by 2 years = €0.75M

**Example 2 – New load customer to be connected**



The connection of G1 and G2 is as before i.e. the cost of building the 110kV/38kV station – as originally charged to generators G1 and G2 - was €5M.

G1 is 15MW and G2 is 20MW, so they were charged as follows:

$$\begin{aligned} \text{G1 charge} &= (\text{€}5\text{M} \times 15) / 35 = \text{approx } \text{€}2.15\text{M} \\ \text{G2 charge} &= (\text{€}5\text{M} \times 20) / 35 = \text{approx } \text{€}2.85\text{M}. \end{aligned}$$

Station was originally constructed and G1 and G2 energised 2 years ago.

D1<sup>48</sup> however is a load customer of size 20MW.

However in this instance the charge to D1 is based on the ultimate firm capacity of the station, rather than the MW share of station users.

From Table 4, Section 4, the ultimate firm capacity of a 110kV/38kV station is 113.4MVA

$$\text{Cost attributable to D1 is therefore} = (\text{€}5\text{M} \times 20) / 113.4 = \text{€}0.88\text{M}$$

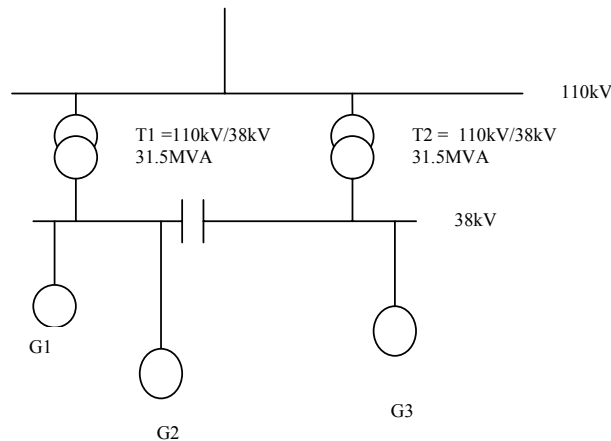
This amount is then refunded to G1 and G2 on a pro-rata basis based on their MW.

$$\text{Refund to G1} = (\text{€}0.88\text{M} \times 20) / 35 = \text{€}0.503\text{M} - \text{depreciated by 2 years} = \text{€}0.48\text{M}$$

$$\text{Refund to G2} = (\text{€}0.88\text{M} \times 15) / 35 = \text{€}0.377\text{M} - \text{depreciated by 2 years} = \text{€}0.36\text{M}$$

<sup>48</sup> Where D1 reflects a system transfer rather than a new load the value of D1 = average load expected over 10 years post transfer.

**Example 3 – charging in green-field scenario. All generators in same Gate (Gate n)**



**Figure 1**

G1 = 10MVA  
 G2 = 15MVA  
 G3 = 25MVA

The only technically acceptable option is for G1 and G2 to be connected to T1, and G3 to be connected to T2. In addition T1 and T2 do not provide any standby facility to each other

As set out in Section3, therefore, charging will be based on asset share and will be as follows:

Transmission costs –

There are three elements to the Transmission costs

1. Transformer bay feeding T1 – cost to be shared pro-rata (based on their MW) between G1 and G2 – **assumed cost of €500k**
2. Transformer bay feeding T2 – cost borne exclusively by G3 – **assumed cost of €500k**
3. Upstream costs (busbar, line bays, line/cable work) cost to be shared pro-rata between all 3 generators on basis of their MW. – **assumed cost of €2.5M**
- 4.

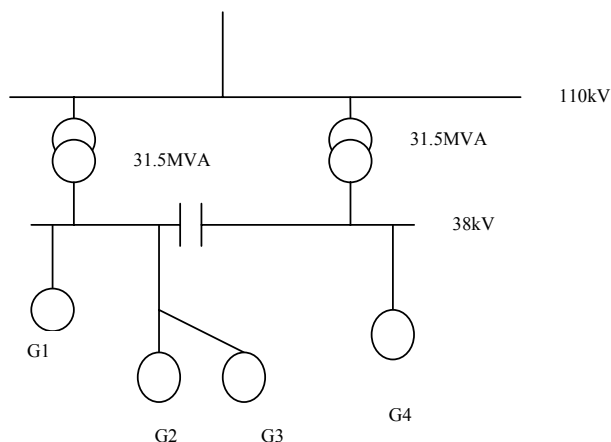
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Assumed transmission costs of €3.5M.

Assumed Distribution cost of €2M

Transmission Costs	3500000	Distribution Costs	2,000,000
<b>G1</b>	700000	<b>G1</b>	400,000
<b>G2</b>	1050000	<b>G2</b>	600,000
<b>G3</b>	1750000	<b>G3</b>	1,000,000

**Example 4 – charging for greenfield connection, where exact transformer connections are not driven by technical or cost issues (Gate n)**



**Figure 2**

G1, 2,3,4 are all in the same Gate and are the following sizes

- G1 = 15MVA
- G2 = 5MVA,
- G3 = 5MVA
- G4 = 15MVA

Because G2 and G3 are located close together and can share some line length, they must be fed from the same transformer (as this leads to Least Cost connection method for group as a whole). However either G1 or G4 could also share the transformer with G2 and G3.

In this case the fairest outcome for the group as a whole to share the cost of both transformers. (The alternative being an arbitrary selection whereby one party bears the full cost of the transformer).

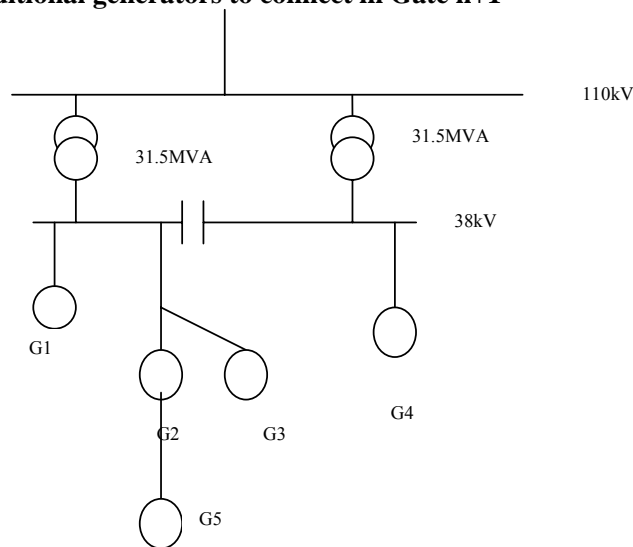
As before Transmission costs = €3M  
 Distribution costs = €2M

In this case both Transmission and Distribution costs are shared equally between all parties.

In addition G2 and G3 are sharing 10km of 38kV line – assumed cost = €100,000 per km = €1M.

<b>Transmission costs</b>	<b>3000000</b>	<b>Distribution Costs</b>	<b>2000000</b>
G1	1125000	G1	750000
G2	375000	G2	250000
G3	375000	G3	250000
G4	1125000	G4	750000
<b>Shared line costs</b>	<b>1000000</b>		
G2	500000		
G3	500000		

**Example 5 – Additional generators to connect in Gate n+1**



**Figure 3**

- G1 = 15MVA
- G2 = 5MVA,
- G3 = 5MVA
- G4 = 15MVA
- G5 = 5MVA

**Note – period between energisation of G1-G4 and G5 = 5 years**

For simplicity, this example will focus on how rebates are calculated for station assets only. Revised share of transmission and distribution station asset costs is as follows<sup>49</sup>:

<b>Transmission Costs</b>	<b>3000000</b>	<b>Distribution Costs</b>	<b>2000000</b>
G1	1000000	G1	666667
G2	333333	G2	222222
G3	333333	G3	222222
G4	1000000	G4	666667
G5	333333	G5	222222

<sup>49</sup> As basis for original transformer share was to be divided equally between all parties, it is most reasonable to continue to share station costs equally, although at this point it would not be possible for G2, G3 and G5 to share the transformer with G4



However refunds to G1-G4 take account of depreciation of assets. Therefore rebates on station assets are as follows:

<b>Transmission assets</b>	<b>Rebate</b>	<b>Distribution Station assets</b>	<b>Rebate</b>
G1	112500	G1	74074
G2	37500	G2	24691
G3	37500	G3	24691
G4	112500	G4	74074

## **Appendix 5 – Relevant Published Documentation**

Transmission Connection Charging Methodology Statement, EirGrid, 14<sup>th</sup> March 2008 - <http://www.eirgrid.com/media/Connection%20Charging%20Statement.pdf>

DSO Standard Pricing Approach for Connecting Renewable Generators to the Distribution Network, Commission Decision, CER/05/090 24<sup>th</sup> June 2005 - <http://www.cer.ie/CERDocs/cer05090.pdf>

Criteria for Gate 3 renewable Generation Offers and related matters CER\08\260 16<sup>th</sup> December 2008

Criteria for Gate 2 Renewable Generator Connection Offers, Direction to the System Operators, CER/06/112 16<sup>th</sup> June 2006 - <http://www.cer.ie/CERDocs/cer06112.pdf>

Group Processing Approach for Renewable Generator Connection Applications, Connection and Pricing Rules, Direction to System Operators, CER/05/049 6<sup>th</sup> April 2005 - <http://www.cer.ie/CERDocs/cer05049.pdf>

Letter from CER clarifying aspects of Standard Pricing for Renewables, 28<sup>th</sup> January 2006  
[http://www.esb.ie/esbnetworks/downloads/letter\\_dso\\_clarifying\\_standard\\_charges\\_for\\_renew.pdf](http://www.esb.ie/esbnetworks/downloads/letter_dso_clarifying_standard_charges_for_renew.pdf)

Standard charges for Generators 2009 cer\08\154  
[http://www.esb.ie/esbnetwork/downloads/approved\\_charges\\_cer\\_2009.pdf](http://www.esb.ie/esbnetwork/downloads/approved_charges_cer_2009.pdf)

Standard Transmission Charges and Timelines, CER/09/077 - <http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=7ab5d769-38ba-450c-b772-74751011d83e>

DSO & TSO Grid Upgrade Development Programme (GUDP): Implementation Guidelines for Generators, June 2003 - <http://www.cer.ie/cerdocs/cer03152.pdf>

TSO Connection Asset Costs: Guiding Principles, CER/ESB/2000/10 12<sup>th</sup> April 2000

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<http://www.eirgrid.com/EirGridPortal/uploads/Regulation%20and%20Pricing/Connection%20Asset%20Costs.pdf>

TSO Contestability and Connection Assets, October 2007 -

<http://www.eirgrid.com/EirgridPortal/uploads/Announcements/contestability%20paper%20oct%202007%2016-10-07.pdf>

TSO 2010 Statement of Charges - [http://www.eirgrid.com/media/2009-](http://www.eirgrid.com/media/2009-2010%20Statement%20of%20Charges%20v1%201%20-%20001%2002%202010%20(CER%20APPROVED).pdf)

[2010%20Statement%20of%20Charges%20v1%201%20-%20001%2002%202010%20\(CER%20APPROVED\).pdf](http://www.eirgrid.com/media/2009-2010%20Statement%20of%20Charges%20v1%201%20-%20001%2002%202010%20(CER%20APPROVED).pdf)

Treatment of Conventional Generator Connection Applicants (consultation)

cer\09\031

Direction on Conventional Offer Issuance Criteria and Matters Related to Gate 3,

Direction to the System Operators, CER /09/191, 18<sup>th</sup> December 2009 -

<http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=8d1fle76-3a9d-470a-b618-348ee8bd5bb3>