



# **Explanatory Paper for 2004 Statement of Charges**

**1<sup>st</sup> January 2004 to 31<sup>st</sup> December 2004**

## Table of Contents

<b>1</b>	<b><i>Introduction</i></b> .....	<b>3</b>
<b>2</b>	<b><i>Revenue requirement, 2004</i></b> .....	<b>4</b>
<b>3</b>	<b><i>Description of the Various Transmission Related Charges</i></b> .....	<b>5</b>
<b>3.1</b>	<b>Network Charge</b> .....	<b>5</b>
3.1.1	Network Capacity Charges.....	5
3.1.2	Network Transfer Charge.....	7
<b>3.2</b>	<b>System Services Charge</b> .....	<b>7</b>
<b>3.3</b>	<b>Capacity Margin Charge</b> .....	<b>7</b>
<b>3.4</b>	<b>Unauthorised capacity charge (applies to DTS-T users only)</b> .....	<b>7</b>
<b>3.5</b>	<b>Transmission Connected Customers Change of Maximum Import Capacity</b> ....	<b>8</b>
<b>4</b>	<b><i>Generation Transmission Service</i></b> .....	<b>9</b>
<b>4.1</b>	<b>Generation Network Capacity charges</b> .....	<b>9</b>
<b>4.2</b>	<b>Treatment of embedded Generators (i.e. connected at distribution voltage)</b> .....	<b>9</b>
<b>4.3</b>	<b>Treatment of Wind Generation</b> .....	<b>9</b>
<b>4.4</b>	<b>Unit Trip Payments</b> .....	<b>9</b>
<b>4.5</b>	<b>Volatility: Generation tariffs</b> .....	<b>9</b>
<b>4.6</b>	<b>Non firm transmission access</b> .....	<b>10</b>
<b>4.7</b>	<b>Generator Commissioning Charge</b> .....	<b>10</b>
<b>5</b>	<b><i>Other Issues</i></b> .....	<b>11</b>
<b>5.1</b>	<b>Treatment of Autoproducers</b> .....	<b>11</b>
<b>5.2</b>	<b>Interconnector Service</b> .....	<b>11</b>
	<b><i>Appendix 1: Demand Transmission Tariffs</i></b> .....	<b>12</b>
	<b><i>Appendix 2: Metered Energy Calculation</i></b> .....	<b>14</b>
	<b><i>Appendix 3: Tariff Calculation Example (Reverse MW-mile approach)</i></b> .....	<b>15</b>

## ***1 Introduction***

This paper describes the structure of ESB National Grid's (ESBNG) Transmission Use of System (TUoS) charging regime for the period 1<sup>st</sup> January 2004 to 31<sup>st</sup> December 2004. The tariffs presented in this document were approved by CER on 03 October 2003 and can be found in the 'Statement of Charges' subsequently approved by CER on 12<sup>th</sup> November 2003.

TUoS tariffs are designed to recover the total costs associated with the transmission business (i.e. the cost of both the TSO and TAO businesses). The total revenue requirement of the transmission business as approved by the CER for the year 2004 amounts to €250m. The transmission tariffs have been designed to fully recover this revenue requirement from transmission "users", which includes both generation and demand users connected directly to the transmission system or indirectly via the distribution system.

It should be noted that the tariffs approved for the year 2004 have been derived consistent with the methodology used to derive the tariffs since year 2000.

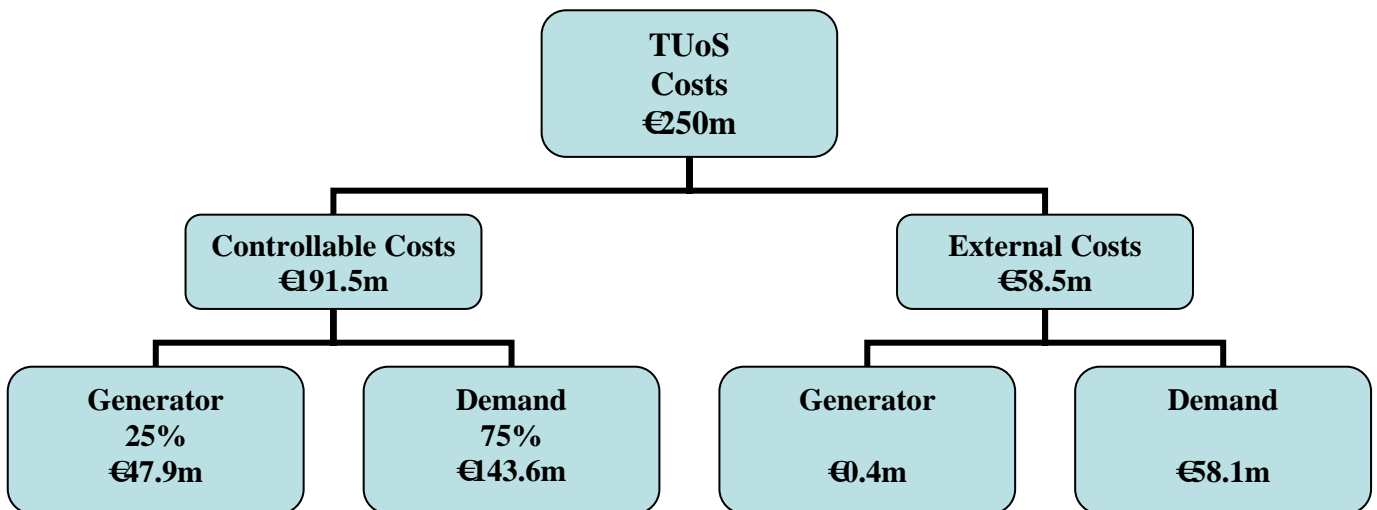
The structure of this document is as follows. Section 2 outlines the revenue requirement as approved by the CER for the year 2004 and provides a breakdown of the proportions recovered from generation and demand users. A description of the various charges that apply to demand users is provided in section 3. Similarly, section 4 provides a detailed description of the generation tariff structure. Section 5 deals with Autoproducers and the Interconnector Service.

## 2 Revenue requirement, 2004

Figure 1 provides an overview of how the total revenue requirement as allowed by CER for the year 2004 (in year 2004 terms), is recovered from Generators and Demand Users. As illustrated, the total revenue allowed to operate the transmission system for year 2004 is €250m. This consists of Controllable costs sometimes referred to as “wires” related costs, (which includes costs associated with depreciation, rate of return, transmission maintenance, capital expenditure and ESB National Grid’s operating expenditure costs) totalling €191.5m and External costs or “non-wires” costs (which includes costs associated with Ancillary Services, Constraints and some DSO wires costs) totalling €58.5m.

As shown in Figure 1 below, 25% of the Controllable costs are recovered from generation and the remaining 75% from demand users. All External costs, with the exception of revenue received from generation trip payments, are recovered from demand users.

**Figure 1: Transmission Revenue Requirement for year 2004 (2004 prices)**



### ***3 Description of the Various Transmission Related Charges***

This section provides a description of the structure of the various transmission tariffs that apply to demand users.

There are three classes of Demand Transmission Service (DTS) provided by ESBNG.

**(1) Tariff Schedule DTS-T:** applies to suppliers serving customers connected directly to the transmission system.

**(2) Tariff Schedule DTS-D1:** applies to suppliers serving customers connected to the distribution system and having a Maximum Import Capacity of 0.5MW or above (before adjusting for the appropriate distribution loss factor).

**(3) Tariff Schedule DTS-D2:** applies to suppliers serving all other *customers connected to the distribution system (including customers supplied by renewable energy suppliers or ‘Green’ customers) who are not served under the other tariff schedules noted above.*

Suppliers on each of the three demand tariff schedules above are liable to pay the various transmission related charges as shown in the respective schedule in the Statement of Charges.

Transmission related charges comprise network charges and system services charges. Network Charges are primarily related to recovery of wires costs. These recover the costs for the use of the transmission system infrastructure for the transportation of electricity in Ireland. 75% of the total wires related costs are recovered from demand users. System Services Charges relate to the recovery of non-wires costs. These recover the costs arising from the operation and security of the transmission system. Specifically, these charges recover the costs associated with ancillary services, system support services and transmission constraints. ESBNG pays the costs of these services to the providers of such services and users pay ESBNG a System Services charge in respect of these costs.

#### ***3.1 Network Charge***

The network charge is divided into two parts; a “Network capacity charge” and a “Network transfer charge”.

##### **3.1.1 Network Capacity Charges**

In relation to the allocation to Demand of the allowed transmission revenue associated with the wires related charges, 60% is allocated to Demand on a fixed basis through a per MW, Network Capacity Charge, or equivalent<sup>1</sup>. This is considered appropriate as the transmission network is primarily a fixed cost that, while designed to meet system

---

<sup>1</sup> The Network Capacity Charge under Tariff Schedule DTS-D2 is based on a per MWh during day hours as a proxy for per MW charging (this is discussed in more detail below).

“coincident peak”<sup>2</sup> at its core, must also be designed to meet the “non-coincident peak” at its extremities.

#### Network Capacity Charge - Tariff Schedule DTS-T

Transmission, or directly connected, customers are currently measured using profile (interval) metering and are contracted to a Maximum Import Capacity (MIC) under the Connection Agreement. This MIC value is used in assessing the capacity charges for each particular customer served by a supplier under Tariff Schedule DTS-T. The MIC value is the level to which ESBNG will design the transmission system to deliver electricity to the customer. The charge has been designed with a bandwidth to allow for a reasonable seasonal variation in demand.

#### Network Capacity Charge - Tariff Schedule DTS-D1

Distribution connected customers with a MIC of 0.5MW or above prior to adjusting for the appropriate distribution loss factor<sup>3</sup> are charged based on Tariff Schedule DTS-D1. This tariff schedule is very similar to Tariff Schedule DTS-T in that the distribution MIC value, after an adjustment for distribution losses, is used in assessing the capacity charge for each particular customer served by a supplier under this schedule. The charge has been similarly designed with a bandwidth to allow for a reasonable seasonal variation in demand.

The charge has also been modified to reflect the fact that distribution connected customers, through diversity of their demands, do not have the same effect on the transmission system at the Grid Exit Point as would a directly connected customer. Consequently, the network capacity charge for customers under the DTS-D1 schedule is below the corresponding charge under the DTS-T charge.

It has not been possible to charge all distribution connected eligible customers on the basis of the DTS-D1 tariff, as information on both MICs and profiled energy consumption for some of these customers is not available. Therefore these customers are charged on the basis of the DTS-D2 tariff, as a proxy for the DTS-D1 tariff. In time it is envisaged that relevant information will become available to charge all appropriate users on DTS-D1 tariff schedule.

#### Network Capacity Charge - Tariff Schedule DTS-D2

Distribution connected customers with an MIC value below the threshold of 0.5MW (prior to adjusting for the appropriate distribution loss factor) are charged based on Tariff Schedule DTS-D2. This constitutes ESB PES demand<sup>4</sup> and the consumption of profiled demands of Green Suppliers. Under Tariff Schedule DTS-D2 the Network Capacity Charge is levied on a variable basis of consumption, which occurs during Day Hours<sup>5</sup>. Day Hour Recovery is considered an effective proxy for having MIC values for all DTS-D2 customers.

---

<sup>2</sup> Within system planning criteria.

<sup>3</sup> See appendix 1 of this document for more details on application of distribution loss factors.

<sup>4</sup> PES Demand is calculated on residual basis as defined in the Statement of Charges.

<sup>5</sup> Day Hours being 08:00 to 23:00 inclusive all days.

### **3.1.2 Network Transfer Charge**

Of the allocation to Demand of the wires related costs, 40% is allocated to Demand on an energy basis through a, per MWh, Network Transfer Charge. Consequently, demand users (i.e. DTS-T, DTS-D1 and DTS-D2) are charged consistent with their associated usage.

Based on a forecast of total energy consumption and on CER's allowed revenue for the year 2004, Table 2 in Appendix 1 provides the Network Transfer Charge for the period, which is the same for all 3 classes of demand customer. The year 2003 corresponding tariff provided below is included for comparative purposes.

### **3.2 System Services Charge**

Costs associated with system services are recovered almost entirely from demand users. This cost is recovered on an energy basis through a, per MWh, charge and it is based on year 2004 projections of system services costs and energy consumption. Table 3 in Appendix 1 provides the System Services Charge for the period (which is the same for all 3 classes of demand customer, following the appropriate adjustment to take account of distribution losses).

### **3.3 Capacity Margin Charge**

A specific charge designed to recover costs associated with the capacity margin has been introduced since 2003 and as directed by the CER is recovered along with TUoS charges. Capacity Margin revenue is not part of Transmission Use of System revenue. This cost is recovered fully from demand users. All 3 classes of demand users are eligible to pay this charge, which has been set at €1.60/MWh for energy consumed during day-time hours.

### **3.4 Unauthorised Usage Charge (applies to DTS-T users only)**

In order to incentivise Demand Users to accurately predict their MIC values, so that ESBNG can develop the system cost effectively while meeting the necessary security standards, an unauthorised usage charge is applicable for demand users connected directly to the transmission system that exceed their MIC. This charge has been levied since 1<sup>st</sup> May 2003 at the rate of €600/MWh as approved by CER.

### **3.5 Change in level of MIC – (applies to DTS-T users only)**

As approved by CER on 04 February 2003 a period of 18 months notice is required from all Transmission connected customers who want to reduce their MIC. Customers must submit a modification request through the connection offer process. This requires a departing or reducing customer to contribute reasonable revenues in respect of the capacity, which was once provided at their request, now being unutilised and would allow any MIC changes to be incorporated in tariff determination. This notice period ensures that customers requesting changes to MIC values are doing so as a result of permanent changing needs and not for the purpose of avoiding capacity charges in the short-term. During the notice period customers would be charged based on their existing MIC for the Network Capacity Charge, hence ensuring all customers pay a minimum of eighteen months capacity charges for the originally requested MIC which the network was built to facilitate.

Customers who request an increase in MIC have less of an effect on tariffs. Where possible the network can be developed to meet their request and they will be charged capacity charges based on the higher MIC value when it is delivered. Customers who bring about the need to enhance the network would be required to apply for a modification to their connection agreement by going through the normal connection offer process and commit to the increased MIC by providing a guarantee bond before necessary network construction works begin. This bond will be calculated based on the increased MW requested multiplied by the Network capacity charge (DTS-T tariff schedule) which applies on the date of the agreement multiplied by eighteen. Customers in this situation would also be required to pay any associated connection charges. Customers who request capacity that already exists will be granted the additional capacity without any connection costs being payable where there is no change to the shallow connection, obviously network capacity charges will be payable based on the higher MIC.

## **4 Generation Transmission Service**

### **4.1 Generation Network Capacity charges**

Of the total allocation of network related costs, 25% is allocated to generation users. This cost is recovered using the Generation Capacity Charge.

Generators connected directly to the transmission system or indirectly via the distribution system<sup>6</sup> currently pay locational use-of-system charges, derived using the 'Reverse MW-mile' methodology. These charges, which are capacity based, provide efficient siting signals to new generators in support of an overall efficient transmission system. Table 6 in Appendix 1 provides firm generation tariffs for the year 2004. A detailed explanation of this methodology used to derive these charges is provided in Appendix 3 of this document.

### **4.2 Treatment of embedded Generators (i.e. connected at distribution voltage)**

Any generator connected to the distribution system with a capacity less than 10MW has a locational Network Capacity Charge rate of zero. Embedded generators above this threshold are liable for a site specific Generator Network Capacity Charge.

### **4.3 Treatment of Wind Generation**

TUoS charges are designed to provide efficient pricing signals to generators connecting to the grid system. Generators who connect to locations that offset flows on the transmission network and hence may offset future transmission investment are rewarded through a lower use-of system charge. Given that wind generation does not provide the same level of security as non-wind generation, and as a result does not offset future investment in the transmission system, the minimum charge applicable to wind generation is zero.

### **4.4 Unit Trip Payments**

Generators above 100MW are eligible for two types of trip payments; the direct trip charge and the fast wind-down trip charge. These charges are payable each time a generator experiences a sudden and immediate loss of output. Table 5 in Appendix 1 shows the charges per MW of trip output in excess of 100MW which generators will incur, for the year 2004.

### **4.5 Volatility: Generation tariffs**

The main objective of the reverse MW-mile methodology is to provide efficient siting signals to generators. However, a possible drawback of this approach from a generator's viewpoint is the presence of price volatility. ESBNG has carried out a

---

<sup>6</sup> As discussed in section 4.1.1 embedded generators below the 10MW threshold have a zero rate for this charge.

number of studies assessing the possible magnitude of the price volatility under a range of network development scenarios. Based on our analysis, generation TUoS charges have the potential to be relatively volatile, especially in a situation where large amounts of generation connect in any location. ESBNG believes that suitable mechanism should be introduced to reduce potential volatility.

ESBNG also proposes to give assistance to current and prospective new generators by publishing 2004 indicative tariffs for every node on the transmission system assuming connection of small amounts of generation. Indicative tariffs proposed in this manner would be, of course, indicative only and siting decisions remain a matter for the generator.

#### **4.6 *Non firm transmission access***

The charge is derived using the generation location based capacity charging methodology currently used for firm access tariffs. The generation charging methodology calculates a site-specific charge per kilowatt per year (kW/year) using the Reverse MW Mile approach. In order to produce a non-firm tariff based on the quantity of energy produced the kilowatt per year charge is converted to a price per kilowatt per hour (kWh). The non-firm transmission tariff is charged to all transmission connected generators for output in excess of the shallow connection capacity during commissioning and prior to the Deemed Firm Date for Dispatchable generators. ESB National Grid is in discussions with CER regarding publishing a non-firm charge for all generators and apply this charge to all energy output in excess of the generator's Maximum Export Capacity for the period after the Deemed Firm Date or Operational Date as appropriate.

#### **4.7 *Generator Commissioning Charge***

Generation Stations and Autoproducers may cause the TSO to incur incremental costs in respect of Ancillary Services, Congestion and Constraints during any commissioning or testing phase of the generator. Charges applied will follow those published on the Eirgrid website in the paper "Generator Testing, Background and Calculation of Commissioning Charges" There is currently a review of the charging methodology underway and it is possible that these charges may change in 2004.

## **5 Other Issues**

### **5.1 Treatment of Autoproducers**

On 17<sup>th</sup> April 2002, the CER published a direction addressing the issue of how autoproducers should be treated in the transmission charging regime. An autoproducer is defined as someone who produces essentially for his own use. On 25<sup>th</sup> September 2003 CER issued a direction extending this to apply to all CHP generators.

CER have ruled that Autoproducers and CHP generators will pay Network Capacity Charges as either a demand user or a generator, but not both. Other TUoS charges are payable as both a demand user and generator as outlined in the 2004 Statement of Charges.

Autoproducers and CHP generators connected to the transmission system will pay Transmission Use of System tariffs under tariff schedule ATS-T. A User connected to the distribution system who is deemed to be an autoproducer will pay charges as outlined on tariff schedule ATS-D in Statement of Charges.

### **5.2 Interconnector Service**

Interconnector users must pay charges for use of the North-South Interconnector as outlined in Schedule ITS on the Statement of Charges. Interconnector Users exporting to Northern Ireland pay Interconnector usage charges to ESB National Grid. A composite document which details all the relevant information on using the interconnector, obtaining interconnector capacity, charges and so on is currently being prepared by ESB National Grid in conjunction with the System Operator of Northern Ireland and shall be published shortly.

## Appendix 1: Demand Transmission Tariffs

**Table 1: Network capacity charge by user class**

User class	Capacity charge, 2003	Capacity charge, 2004
DTS-T	€1317.6967/MW/month	€1,550.0152/MW/month
DTS-D1	€1174.6739/MW/month	€1,336.1326/MW/month
DTS-D2	€4.3634/MWh	€5.2094/MWh

**Table 2: Network Transfer charge**

Year	Tariff rate
2003	€1.9626/MWh
2004	€2.3665/MWh

**Table 3: System Services Charge**

Year	Tariff rate
2003	€2.5116MWh
2004	€2.3927MWh

**Table 4: Capacity Margin Charge**

Year	Tariff rate
2003	€2.0996/MWh
2004	€1.60MWh

**Table 5: Generator Unit Trip Payments**

Description	Amount
System Services Direct Trip Charge	€1.2043/MW
System Services Fast wind-down charge	€0.6021/MW

**Table 6: Generation locational charges, January 04 to December 04**

Station	Units	Capacity	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
Aghada	AD1, AT1, AT2, AT4	528.0 MW	€649.8500	€7.7982
Ardnacrusha	AA1,AA2 AA3,AA4	85.5 MW	-€29.6333	-€0.3556
Bellacorick	BK1,BK2	36.8 MW	€9.2333	€0.1108
Edenderry		117.6 MW	€402.6000	€4.8312
Power				
Erne	ER1,ER2	45.0 MW	€75.8167	€0.9098
Erne	ER3,ER4	20.0 MW	€108.6083	€1.3033
Golagh	GOW	15.0 MW	€330.8667	€3.9704
Great Island	GI1,GI2	114.0 MW	€247.4083	€2.9689
Great Island	GI3	112.0 MW	€329.0667	€3.9488
Huntstown	CT,ST	352.0 MW	€573.0167	€6.8762
Irishtown		400.0 MW	€773.6667	€9.2840
Lanesboro	LA2,LA8	128.0 MW	€278.8750	€3.3465
Lee	LE3	8.0 MW	€419.3667	€5.0324
Lee	LE1,LE2	19.0 MW	€496.6083	€5.9593
Liffey	LI1,LI2	30.0 MW	€565.6750	€6.7881
MARIG1	MR1,MRT	112.3 MW	€401.7917	€4.8215
Moneypoint	MP1,MP2, MP3	862.5 MW	€1,115.1167	€13.3814
Northwall	NW 1,NW 2, NW 3	44.0 MW	€504.8250	€6.0579
Northwall	NW 4,NW 5	227.0 MW	€1,260.3667	€15.1244
Poolbeg	PB1,PB2, PB3	486.0 MW	€1,040.8917	€12.4907
Poolbeg	PB4,PB5, PB6	457.0 MW	€788.3917	€9.4607
Shannonbridge	SH1	37.0 MW	€10.3333	€0.1240
Shannonbridge	SH2,SH3	77.5 MW	€140.0500	€1.6806
TARBG1	TB1,TB2	114.0 MW	€716.4333	€8.5972
TARBG3	TB3,TB4	481.4 MW	€794.2500	€9.5310
Turl_Hil	TH1,TH2 TH3,TH4	292.0 MW	€883.2667	€10.5992
Cunghill		23.8 MW	€0.0000	€0.0000
Derrybrien		60.0 MW	€268.4083	€3.2209
Meentycat		43.6 MW	€242.3167	€2.9078
	<b>Connected at</b>			
Seorgus Wind	Tralee	15.0 MW	€361.3417	€4.3361
Cark Wind	Leterkenny	15.0 MW	€151.0667	€1.8128
Culliagh Wind	Letterkenny	11.9 MW	€151.0667	€1.8128
Carnsore Wind	Wexford	11.9 MW	€69.7667	€0.8372
Arklow Wind	Arklow	25.5 MW	€323.5083	€3.8821
Raheen Barr Wind	Castlebar	18.7 MW	€0.0000	€0.0000
Moanmore Wind	Tullabrack	12.6 MW	€0.0000	€0.0000
Gartnaneane	Meath Hill	10.5 MW	€41.0667	€0.4928
Beam Hill Wind	Trillick	14.0 MW	€177.5417	€2.1305
Sorne Hill Wind	Trillick	31.5 MW	€177.5417	€2.1305
Richfield Wind	Wexford	20.3 MW	€69.7667	€0.8372
	<b>Emergency Generators</b>			
Aghada		52.0 MW	€652.1750	€7.8261
Tawnaghamore		52.0 MW	€26.1917	€0.3143

## Appendix 2: Metered Energy Calculation

This appendix provides an example of how a user’s metered energy is adjusted by the applicable distribution loss factor to derive the metered energy value, as defined in ESBNG’s Statement of Charges.

The metered data files generated by MRSO contains average kW readings for each Demand Transmission customer for each fifteen minute interval, in each settlement day. The TUoS application system converts these kW readings to MWh readings by dividing each reading by 4000 (i.e. 1000\*4).

For example, consider a customer with a demand of 1400 kW and 1200 kW in two consecutive 15 minute periods in a given trading interval (i.e. half hour period). These kW readings are converted to MWh readings as follows:

$$1400 \text{ kW-15avg}/1000 \text{ kW/MW} = 1.4 \text{ MW-15avg}/4 \text{ MWh/MW-15avg} = 0.35 \text{ MWh}$$

$$1200 \text{ kW-15avg}/1000 \text{ kW/MW} = 1.2 \text{ MW-15avg}/4 \text{ MWh/MW-15avg} = 0.30 \text{ MWh}$$

These MWh readings are then adjusted by the relevant distribution loss factor and summed together to provide the total metered energy value in that trading period. The settlement day is divided into day hours and night hours, with different Distribution Loss Factors (DLF) applicable to day and night readings. Day hours are defined as 08:00 to 23:00 with night being 23:00 to 08:00.

So in our example, if we assume that the user is connected at 38kV and is a D1 customer, then assuming that the trading interval has occurred during day time hours, the metered energy value is equal to  $0.35 * 1.018 + 0.30 * 1.018$ .

In a billing period (i.e. in a given month) the network transfer charge and the system services charge are then derived by multiplying this metered energy value by the network transfer tariff rate and the system services tariff rate, respectively.

Capacity related charges are also levied for each billing period (i.e. month in question) consistent with the rules as outlined in ESBNG’s Statement of Charges.

Table A.1. Distribution loss factors 2004

Voltage	Day	Night
220 kV	1	1
110/220 kV	1	1
38 kV	1.016	1.014
LV	1.095	1.08
MV	1.043	1.036

Note: Day Hours = 08:00 to 23:00 hours inclusive on any day

### Appendix 3: Tariff Calculation Example (Reverse MW-mile approach)

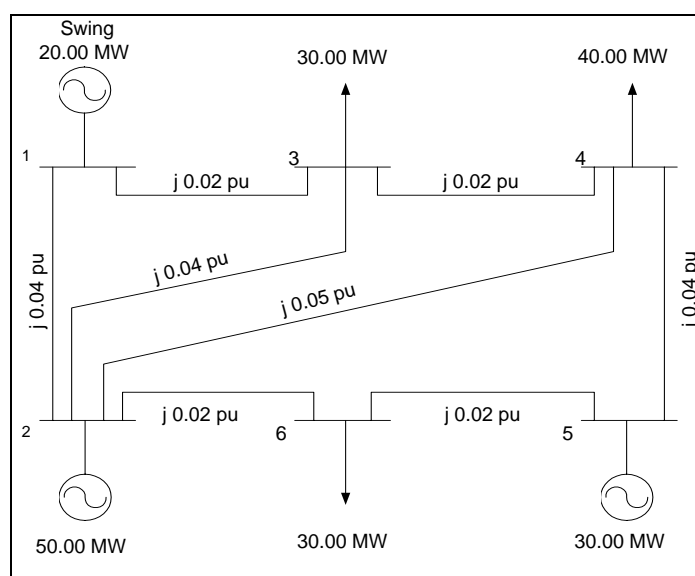
This Appendix presents a detailed explanation of the Reverse MW-Mile approach applied to an example small system, comprising 6 buses and 8 circuits. This approach is used to derive ESBNG's generation locational transmission charges. All calculations are carried out using a specialised software package called 'Integra'.

There are three main steps involved in deriving generation charges:

- (1) the use of each circuit by each generator is determined using load flow analysis. This analysis requires the specification of generation and demand at each point on the network. The load flow study then calculates the flow of all power from generators to demand sinks, based on peak load conditions.
- (2) transmission assets are valued based on replacement costs. The cost of each circuit includes a depreciation charge, operations and maintenance overheads plus an appropriate rate of return. Station costs are apportioned to each line connecting into that station on a per bay basis.
- (3) Generators are charged for each circuit in direct proportion to their contribution. A key feature of the Reverse MW-mile approach is that generators which off-set flows are rewarded, by crediting counter-flows. Due mainly to the lumpiness of transmission investment, at any given point in time, spare capacity (i.e. differences between the rated capacity of an asset and the extent to which is used by all network users) will exist on the transmission system. The cost associated with the spare capacity on all circuits is averaged across all users (as opposed to charging the full cost of a circuit to the specific users of each circuit).

#### **Illustrative Example**

A simple 6 bus system illustrated below is used to provide an understanding of the workings of the Reverse MW-mile approach.



**Figure 2 – System Example**

This system is assumed to have 3 generators serving a total system demand of 100MW. For simplicity the capacity of all circuits is assumed to be 50MW and the annual value (i.e. includes depreciation, RoR and O&M) of each circuit is assumed to be €50,000.

### Step 1(a) – Load Flow Calculation

A DC power flow is calculated to identify the circuit flows of the system. It is important to determine the direction of the flow in each circuit caused by each generator. If the circuit flow caused by the generator and the total circuit flow in a circuit are in the same direction, the flow is called ‘dominant’. If the flows are in opposite direction to the dominant flow, the flow is called ‘reverse’. When the generator is responsible for a dominant flow, then that generator is increasing the flow in the circuit, and pays for its use. However, if a generator is responsible for a reverse flow, then that generator is reducing the flow in the circuit, and receives credit for postponing the expansion of the transmission system.

To determine the contribution of each generator to circuit flows it is necessary first to run a load flow that matches total system demand and generation.

The formulation of the linear power flow (DC approach) is presented below:

$$P_{ij} = x_{ij}^{-1} \cdot \theta_{ij} \quad P_{ij} = \text{circuit flow (pu)} - \text{base 100 MVA}$$

$$x_{ij} = \text{circuit reactance (pu)}$$

$$\theta_{ij} = \text{angle between the buses i and j (rad)}$$

$$P_i = \sum x_{ij}^{-1} \cdot \theta_{ij} \quad P_i = \text{net injection} = P_{Gi} - P_{Li} \text{ (pu)}$$

$$P_i = \left( \sum x_{ij}^{-1} \right) \cdot \theta_i + \left( \sum -x_{ij}^{-1} \right) \cdot \theta_j$$

In matrix form:

$$P = B \cdot \theta$$

$$B_{ij} = -x_{ij}^{-1}$$

$$B_{ii} = \sum x_{ij}^{-1}$$

Using the numerical values of the system example:

$$P = B \cdot \theta$$

$$\begin{bmatrix} 0.20 \\ 0.50 \\ -0.30 \\ -0.40 \\ 0.30 \\ -0.30 \end{bmatrix} = \begin{bmatrix} 75 & -25 & -50 & 0 & 0 & 0 \\ -25 & 120 & -25 & -20 & 0 & -50 \\ -50 & -25 & 125 & -50 & 0 & 0 \\ 0 & -20 & -50 & 95 & -25 & 0 \\ 0 & 0 & 0 & -25 & 75 & -50 \\ 0 & -50 & 0 & 0 & -50 & 100 \end{bmatrix} \cdot \begin{bmatrix} \theta_1 = 0 \\ \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix}$$

However, the matrix B is singular, so it doesn't have inverse. Consequently, it is necessary to reduce the matrix by the terms of the swing bus (bus 1).

$$P = B' \theta$$

$$\begin{bmatrix} 0.50 \\ -0.30 \\ -0.40 \\ 0.30 \\ -0.30 \end{bmatrix} = \begin{bmatrix} 120 & -25 & -20 & 0 & -50 \\ -25 & 125 & -50 & 0 & 0 \\ -20 & -50 & 95 & -25 & 0 \\ 0 & 0 & -25 & 75 & -50 \\ -50 & 0 & 0 & -50 & 100 \end{bmatrix} \cdot \begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix}$$

To calculate the value of the angle  $\theta_{ij}$ , and after that the circuit flow  $P_{ij}$ , it is necessary to solve this equation:

$$\theta = (B')^{-1} \cdot P$$

$$\begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix} = (B')^{-1} \cdot P = \begin{bmatrix} 0.0013 \\ -0.0046 \\ -0.0062 \\ 0.0005 \\ -0.0021 \end{bmatrix}$$

The flow in each circuit is obtained by the expression:

$$P_{ij} = -B_{ij} \cdot \theta_{ij}$$

$$P_{12} = -B_{12} \cdot \theta_{12} = 25 \cdot (-1.284 \cdot 10^{-3}) = -0.0321 \text{ pu} = -3.21 \text{ MW}$$

$$P_{13} = -B_{13} \cdot \theta_{13} = 50 \cdot (4.642 \cdot 10^{-3}) = 0.2321 \text{ pu} = 23.21 \text{ MW}$$

$$P_{23} = -B_{23} \cdot \theta_{23} = 25 \cdot (5.924 \cdot 10^{-3}) = 0.1481 \text{ pu} = 14.81 \text{ MW}$$

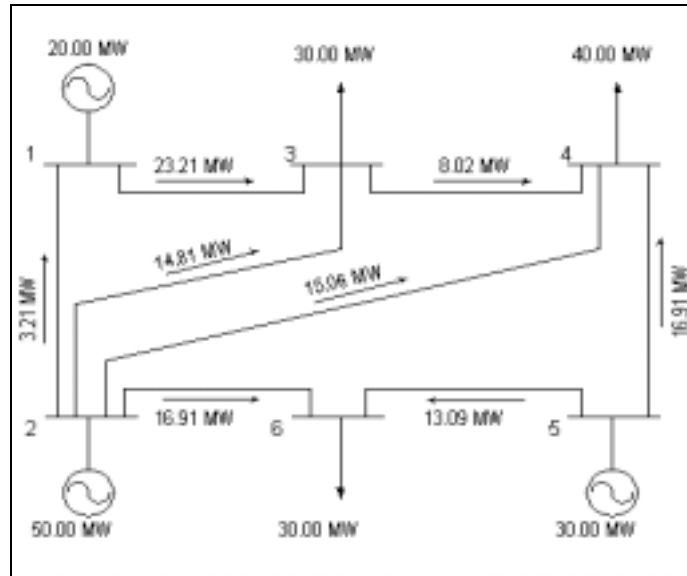
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (7.530 \cdot 10^{-3}) = 0.1506 \text{ pu} = 15.06 \text{ MW}$$

$$P_{26} = -B_{26} \cdot \theta_{26} = 50 \cdot (3.382 \cdot 10^{-3}) = 0.1691 \text{ pu} = 16.91 \text{ MW}$$

$$P_{34} = -B_{34} \cdot \theta_{34} = 50 \cdot (1.604 \cdot 10^{-3}) = 0.0802 \text{ pu} = 8.02 \text{ MW}$$

$$P_{45} = -B_{45} \cdot \theta_{45} = 25 \cdot (-6.764 \cdot 10^{-3}) = -0.1691 \text{ pu} = -16.91 \text{ MW}$$

$$P_{56} = -B_{56} \cdot \theta_{56} = 50 \cdot (2.618 \cdot 10^{-3}) = 0.1309 \text{ pu} = 13.09 \text{ MW}$$



### Circuit Flows

System Generation = Generation Bus1 + Generation Bus2 + Generation Bus5  
 System Generation = 20 + 50 + 30 = 100 MW

#### Step (1b)– Power flow caused by each generator

To calculate the circuit flow caused by each generator we run a power flow representing all generators except the one we are studying. The total system load should be reduced proportionally to match the system dispatch. The flow in each circuit caused by the generator we are studying is equal to the total flow in the circuit (i.e. basecase scenario) minus the flow we obtain when running a loadflow without the generator under study.

After calculating the circuit flows, and determining whether flows are dominant or reverse, we calculate the locational signal (MW-Mile Tariff before applying the Postage Stamp Coverage) associated with each generator.

#### Generator at Bus 1 – Circuits Flow

System Generation = 80 MW = 0.80 pu  
 Generation at Bus 1 = 0 MW = 0.00 pu  
 Generation at Bus 2 = 50 MW = 0.50 pu  
 Generation at Bus 5 = 30 MW = 0.30 pu

Load at Bus 3 = 30% x 80MW = 24 MW = 0.24 pu  
 Load at Bus 4 = 40% x 80MW = 32 MW = 0.32 pu  
 Load at Bus 6 = 30% x 80MW = 24 MW = 0.24 pu

$$\begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix} = \mathbf{B}^{-1} \cdot \mathbf{P} = \mathbf{B}^{-1} \cdot \begin{bmatrix} 0.50 \\ -0.24 \\ -0.32 \\ 0.30 \\ -0.24 \end{bmatrix} = \begin{bmatrix} 4.1218 \\ -2.0609 \\ -2.4132 \\ 4.4543 \\ 1.8881 \end{bmatrix} \cdot 10^{-3}$$

$$P_{12} = -B_{12} \cdot \theta_{12} = 25 \cdot (-4.1218 \cdot 10^{-3}) = -0.1030 \text{ pu} = -10.30 \text{ MW}$$

$$P_{13} = -B_{13} \cdot \theta_{13} = 50 \cdot (2.0609 \cdot 10^{-3}) = 0.1030 \text{ pu} = 10.30 \text{ MW}$$

$$P_{23} = -B_{23} \cdot \theta_{23} = 25 \cdot (6.1827 \cdot 10^{-3}) = 0.1545 \text{ pu} = 15.45 \text{ MW}$$

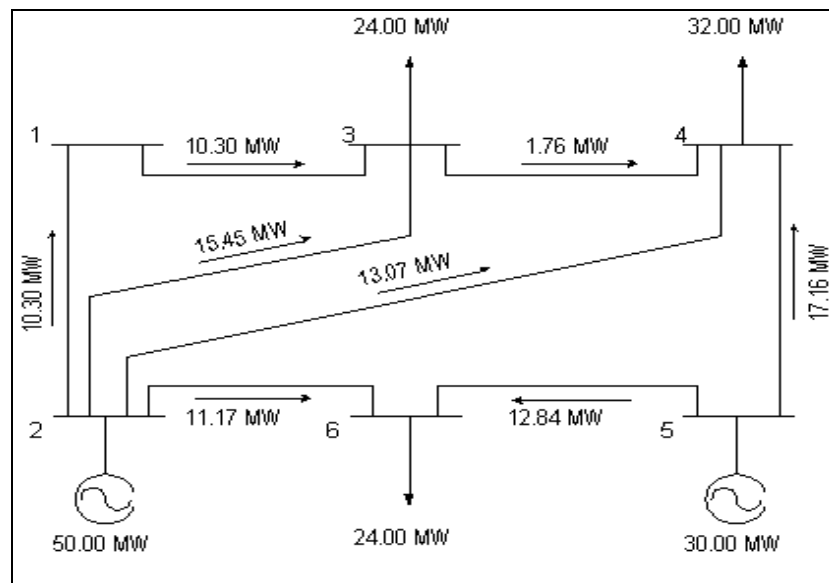
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (6.5350 \cdot 10^{-3}) = 0.1307 \text{ pu} = 13.07 \text{ MW}$$

$$P_{26} = -B_{26} \cdot \theta_{26} = 50 \cdot (2.2337 \cdot 10^{-3}) = 0.1117 \text{ pu} = 11.17 \text{ MW}$$

$$P_{34} = -B_{34} \cdot \theta_{34} = 50 \cdot (0.3523 \cdot 10^{-3}) = 0.0176 \text{ pu} = 1.76 \text{ MW}$$

$$P_{45} = -B_{45} \cdot \theta_{45} = 25 \cdot (-6.8675 \cdot 10^{-3}) = -0.1716 \text{ pu} = -17.16 \text{ MW}$$

$$P_{56} = -B_{56} \cdot \theta_{56} = 50 \cdot (2.5663 \cdot 10^{-3}) = 0.1284 \text{ pu} = 12.84 \text{ MW}$$



**Circuit Flows Obtained Without Generator 1**

Report of Circuit Flows:

CIRCUIT	TOTAL (MW)	GENERATOR 2 + GENERATOR 5 (MW)	GENERATOR 1 (MW)
1 – 2	-3.21	-10.30	7.09
1 – 3	23.21	10.30	12.91
2 – 3	14.81	15.45	-0.64
2 – 4	15.06	13.07	1.99
2 – 6	16.91	11.17	5.74
3 – 4	8.02	1.76	6.26
4 – 5	-16.91	-17.16	0.25
5 – 6	13.09	12.84	0.25

Note: The circuit flow caused by generator 1 is calculated as the total circuit flow minus the circuit flow caused by the generators 2 and 5.

**Generator at Bus 2 – Circuits Flow**

System Generation = 50 MW = 0.50 pu  
 Generation at Bus 1 = 20 MW = 0.20 pu  
 Generation at Bus 2 = 0 MW = 0.00 pu  
 Generation at Bus 5 = 30 MW = 0.30 pu

Load at Bus 3 = 30% x 50 MW = 15 MW = 0.15 pu  
 Load at Bus 4 = 40% x 50 MW = 20 MW = 0.20 pu  
 Load at Bus 6 = 30% x 50 MW = 15 MW = 0.15 pu

$$\begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix} = B^{-1} \cdot P = B^{-1} \cdot \begin{bmatrix} 0.00 \\ -0.15 \\ -0.20 \\ 0.30 \\ -0.15 \end{bmatrix} = \begin{bmatrix} -1.9095 \\ -3.0453 \\ -3.6584 \\ 1.7160 \\ -1.5967 \end{bmatrix} \cdot 10^{-3}$$

$$P_{12} = -B_{12} \cdot \theta_{12} = 25 \cdot (1.9095 \cdot 10^{-3}) = 0.0477 \text{ pu} = 4.77 \text{ MW}$$

$$P_{13} = -B_{13} \cdot \theta_{13} = 50 \cdot (3.0453 \cdot 10^{-3}) = 0.1523 \text{ pu} = 15.23 \text{ MW}$$

$$P_{23} = -B_{23} \cdot \theta_{23} = 25 \cdot (1.1358 \cdot 10^{-3}) = 0.0283 \text{ pu} = 2.83 \text{ MW}$$

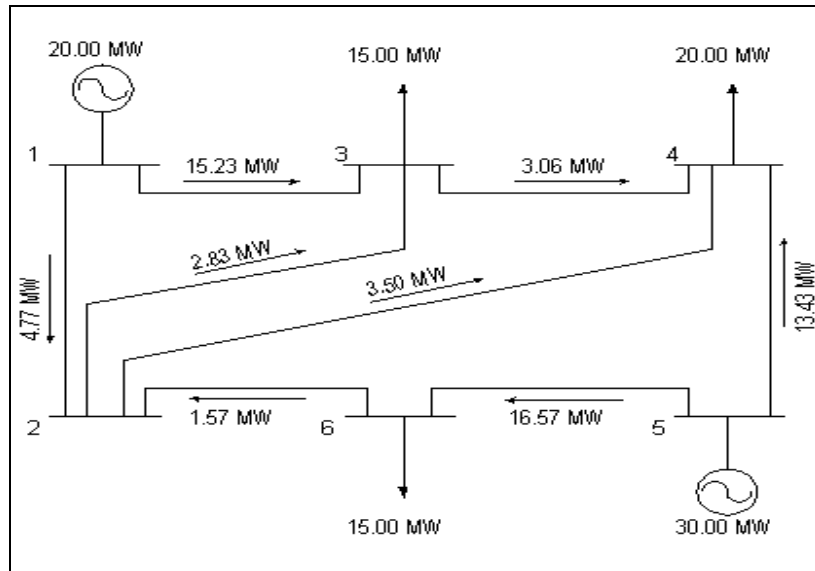
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (1.7490 \cdot 10^{-3}) = 0.0350 \text{ pu} = 3.50 \text{ MW}$$

$$P_{26} = -B_{26} \cdot \theta_{26} = 50 \cdot (-0.3127 \cdot 10^{-3}) = -0.0157 \text{ pu} = -1.57 \text{ MW}$$

$$P_{34} = -B_{34} \cdot \theta_{34} = 50 \cdot (0.6132 \cdot 10^{-3}) = 0.0306 \text{ pu} = 3.06 \text{ MW}$$

$$P_{45} = -B_{45} \cdot \theta_{45} = 25 \cdot (-5.3745 \cdot 10^{-3}) = -0.1343 \text{ pu} = -13.43 \text{ MW}$$

$$P_{56} = -B_{56} \cdot \theta_{56} = 50 \cdot (3.3127 \cdot 10^{-3}) = 0.1657 \text{ pu} = 16.57 \text{ MW}$$



**Circuit Flows Obtained Without Generator 2**

Report of Circuit Flows:

CIRCUIT	TOTAL (MW)	GENERATOR 1 + GENERATOR 5 (MW)	GENERATOR 2 (MW)
1 – 2	-3.21	4.77	-7.98
1 – 3	23.21	15.23	7.98
2 – 3	14.81	2.83	11.98
2 – 4	15.06	3.50	11.56
2 – 6	16.91	-1.57	18.48
3 – 4	8.02	3.06	4.96
4 – 5	-16.91	-13.43	-3.48
5 – 6	13.09	16.57	-3.48

Note: The circuit flow caused by generator 2 is calculated as the total circuit flow minus the circuit flow caused by the generators 1 and 5.

### Generator at Bus 5 – Circuits Flow

System Generation = 70 MW = 0.70 pu  
 Generation at Bus 1 = 20 MW = 0.20 pu  
 Generation at Bus 2 = 50 MW = 0.50 pu  
 Generation at Bus 5 = 0 MW = 0.00 pu

Load at Bus 3 = 30% x 70 MW = 21 MW = 0.21 pu  
 Load at Bus 4 = 40% x 70 MW = 28 MW = 0.28 pu  
 Load at Bus 6 = 30% x 70 MW = 21 MW = 0.21 pu

$$\begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix} = \mathbf{B}^{-1} \cdot \mathbf{P} = \mathbf{B}^{-1} \cdot \begin{bmatrix} 0.50 \\ -0.21 \\ -0.28 \\ 0.00 \\ -0.21 \end{bmatrix} = \begin{bmatrix} 0.3555 \\ -4.1778 \\ -6.4222 \\ -5.1333 \\ -4.4889 \end{bmatrix} \cdot 10^{-3}$$

$$P_{12} = -B_{12} \cdot \theta_{12} = 25 \cdot (-0.3555 \cdot 10^{-3}) = -0.0089 \text{ pu} = -0.89 \text{ MW}$$

$$P_{13} = -B_{13} \cdot \theta_{13} = 50 \cdot (4.1778 \cdot 10^{-3}) = 0.2089 \text{ pu} = 20.89 \text{ MW}$$

$$P_{23} = -B_{23} \cdot \theta_{23} = 25 \cdot (4.5333 \cdot 10^{-3}) = 0.1133 \text{ pu} = 11.33 \text{ MW}$$

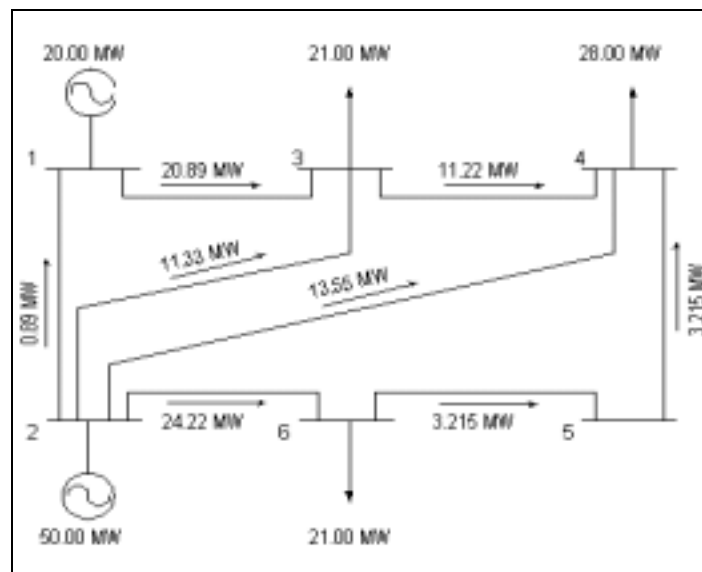
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (6.7778 \cdot 10^{-3}) = 0.1355 \text{ pu} = 13.55 \text{ MW}$$

$$P_{26} = -B_{26} \cdot \theta_{26} = 50 \cdot (4.8444 \cdot 10^{-3}) = 0.2422 \text{ pu} = 24.22 \text{ MW}$$

$$P_{34} = -B_{34} \cdot \theta_{34} = 50 \cdot (2.2444 \cdot 10^{-3}) = 0.1122 \text{ pu} = 11.22 \text{ MW}$$

$$P_{45} = -B_{45} \cdot \theta_{45} = 25 \cdot (-1.2889 \cdot 10^{-3}) = -0.03215 \text{ pu} = -3.215 \text{ MW}$$

$$P_{56} = -B_{56} \cdot \theta_{56} = 50 \cdot (-0.6444 \cdot 10^{-3}) = -0.03215 \text{ pu} = -3.215 \text{ MW}$$



**Circuit Flows Obtained Without Generator 5**

## Report of Circuit Flows

CIRCUIT	TOTAL (MW)	GENERATOR 1 + GENERATOR 2 (MW)	GENERATOR 5 (MW)
1 – 2	-3.21	-0.89	-2.32
1 – 3	23.21	20.89	2.32
2 – 3	14.81	11.33	3.48
2 – 4	15.06	13.55	1.51
2 – 6	16.91	24.22	-7.31
3 – 4	8.02	11.22	-3.20
4 – 5	-16.91	-3.215	-13.70
5 – 6	13.09	-3.215	16.31

Note: The circuit flow caused by generator 5 is calculated as the total circuit flow minus the circuit flow caused by the generators 1 and 2.

## Summary Report of Circuits Flow

CIRCUITS	TOTAL	GENERATOR 1 (20 MW)	GENERATOR 2 (50 MW)	GENERATOR 5 (30 MW)
1 – 2	-3.21	7.09	-7.98	-2.32
1 – 3	23.21	12.91	7.98	2.32
2 – 3	14.81	-0.64	11.98	3.48
2 – 4	15.06	1.99	11.56	1.51
2 – 6	16.91	5.74	18.48	-7.31
3 – 4	8.02	6.26	4.96	-3.20
4 – 5	-16.91	0.25	-3.48	-13.70
5 – 6	13.09	0.25	-3.48	16.31

## Step 2 Costs associated with each circuit

For simplicity (as discussed above) it is assumed that the value of each circuit is equal to €50,000.

CIRCUIT	COST (£)	CAPACITY (MW)
1 – 2	$50 \cdot 10^3$	50
1 – 3	$50 \cdot 10^3$	50
2 – 3	$50 \cdot 10^3$	50
2 – 4	$50 \cdot 10^3$	50
2 – 6	$50 \cdot 10^3$	50
3 – 4	$50 \cdot 10^3$	50
4 – 5	$50 \cdot 10^3$	50
5 – 6	$50 \cdot 10^3$	50

### Step 3: Deriving generation locational charges

Given the results of the loadflow analysis and using the cost assumptions provided above, in this section we derive the locational signals for the simple system under study.

#### Generator at bus 1

CIRCUIT	COST (€)	CAPACITY (MW)	GENERATOR'S POWER FLOW (MW)	DIRECT (D) OR REVERSE (R)	LOCATIONAL SIGN PAYMENT (€)
1 – 2	$50 \cdot 10^3$	50	7.09	R	-7090.00
1 – 3	$50 \cdot 10^3$	50	12.91	D	12910.00
2 – 3	$50 \cdot 10^3$	50	-0.64	R	-640.00
2 – 4	$50 \cdot 10^3$	50	1.99	D	1990.00
2 – 6	$50 \cdot 10^3$	50	5.74	D	5740.00
3 – 4	$50 \cdot 10^3$	50	6.26	D	6260.00
4 – 5	$50 \cdot 10^3$	50	0.25	R	-250.00
5 – 6	$50 \cdot 10^3$	50	0.25	D	250.00
TOTAL					19170.00

$$R_1 = \sum_{k=1}^{n_{in}} \frac{c_k}{k_k} \cdot w_k^1 \quad (\text{amount paid by the generator at bus 1})$$

$c_k$  = cost of circuit k

$k_k$  = capacity of circuit k

$w_k^1$  = circuit flow caused by generator 1 on circuit k

$\pi_1$  = locational tariff

$$R_1 = \frac{50 \cdot 10^3 (\text{€})}{50 \text{ MW}} \cdot (-7.09 + 12.91 - 0.64 + 1.99 + 5.74 + 6.26 - 0.25 + 0.25) \text{ MW}$$

$$R_1 = 19170.00 (\text{€})$$

$$\pi_1 = \frac{R_1}{PG_1} = \frac{19.17 \cdot 10^3 (\text{€})}{20 \cdot 10^3 \text{ KW}} = 0.9585 (\text{€}) / \text{KW}$$

### Generator at bus 2

Should amounts in this section be Euro(€) rather than £?

CIRCUIT	COST (€)	CAPACITY (MW)	GENERATOR'S POWER FLOW (MW)	DIRECT (D) OR REVERSE (R)	LOCATIONAL SIGN PAYMENT (€)
1 – 2	$50 \cdot 10^3$	50	-7.98	D	7980.00
1 – 3	$50 \cdot 10^3$	50	7.98	D	7980.00
2 – 3	$50 \cdot 10^3$	50	11.98	D	11980.00
2 – 4	$50 \cdot 10^3$	50	11.56	D	11560.00
2 – 6	$50 \cdot 10^3$	50	18.48	D	18480.00
3 – 4	$50 \cdot 10^3$	50	4.96	D	4960.00
4 – 5	$50 \cdot 10^3$	50	-3.48	D	3480.00
5 – 6	$50 \cdot 10^3$	50	-3.48	R	-3480.00
<b>TOTAL</b>					<b>62940.00</b>

$$R_2 = \sum_{k=1}^{n_{lin}} \frac{c_k}{k_k} \cdot w_k^2 \quad (\text{i.e. amount paid by the generator 2})$$

$c_k$  = cost of circuit k

$k_k$  = capacity of circuit k

$w_k^2$  = circuit flow caused by generator 2 on circuit k

$\pi_2$  = locational sign tariff

$$R_2 = \frac{50 \cdot 10^3 (\text{€})}{50 \text{ MW}} \cdot (7.98 + 7.98 + 11.98 + 11.56 + 18.48 + 4.96 + 3.48 - 3.48) \text{ MW}$$

$$R_2 = 62940 (\text{€})$$

$$\pi_2 = \frac{R_2}{PG_2} = \frac{62.94 \cdot 10^3 (\text{€})}{50 \cdot 10^3 \text{ KW}} = 1.2588 (\text{€}) / \text{KW}$$

## Generator at bus 5

CIRCUIT	COST (€)	CAPACITY (MW)	GENERATOR'S POWER FLOW (MW)	DIRECT (D) OR REVERSE (R)	LOCATIONAL SIGN PAYMENT (€)
1 – 2	$50 \cdot 10^3$	50	-2.32	D	2320.00
1 – 3	$50 \cdot 10^3$	50	2.32	D	2320.00
2 – 3	$50 \cdot 10^3$	50	3.48	D	3480.00
2 – 4	$50 \cdot 10^3$	50	1.51	D	1510.00
2 – 6	$50 \cdot 10^3$	50	-7.31	R	-7310.00
3 – 4	$50 \cdot 10^3$	50	-3.20	R	-3200.00
4 – 5	$50 \cdot 10^3$	50	-13.70	D	13700.00
5 – 6	$50 \cdot 10^3$	50	16.31	D	16310.00
<b>TOTAL</b>					<b>29130.00</b>

$$R_5 = \sum_{k=1}^{n_{lin}} \frac{c_k}{k_k} \cdot w_k^5 \quad (\text{i.e. amount paid by generator 5})$$

$c_k$  = cost of circuit k

$k_k$  = capacity of circuit k

$w_k^5$  = circuit flow caused by generator 5 on circuit k

$\pi_5$  = locational sign tariff

$$R_5 = \frac{50 \cdot 10^3 (\text{€})}{50 \text{ MW}} \cdot (2.32 + 2.32 + 3.48 + 1.51 - 7.31 - 3.20 + 13.70 + 16.31) \text{ MW}$$

$$R_5 = 29130 (\text{€})$$

$$\pi_5 = \frac{R_5}{PG_5} = \frac{29.13 \cdot 10^3 (\text{€})}{30 \cdot 10^3 \text{ KW}} = 0.9710 (\text{€}) / \text{KW}$$

## Postage Stamp Coverage

The locational sign is not sufficient to remunerate the total transmission system cost. To cover the total transmission system cost, it will be necessary to share among the generators the costs associated with unused capacity. The Postage Stamp (or average) coverage is the methodology used to distribute this cost among the generators. This methodology is presented below:

$$\text{Transmission Revenue: } 8 \text{ circuits} \times 50 \cdot 10^3 (\text{€}) = 400 \cdot 10^3 (\text{€})$$

Total Revenue by Locational Sign =  $R_1 + R_2 + R_5 = (19.17+62.94+29.13) \cdot 10^3 = 111.24 \cdot 10^3$  (€)

Transmission system cost not remunerated:  $400 \cdot 10^3 - 111.24 \cdot 10^3 = 288.76 \cdot 10^3$  (€)

Postage Stamp:  $\Delta = \frac{288.76 \cdot 10^3 \text{ (€)}}{100 \cdot 10^3 \text{ KW}} = 2.8876 \text{ (€) / KW}$

BUS NUMBER	LOCATIONAL SIGNAL TARIFF (€/KW)	POSTAGE STAMP TARIFF (€/KW)	TOTAL TARIFF (€/KW)
1	0.9585	2.8876	3.8461
2	1.2588	2.8876	4.1464
5	0.9710	2.8876	3.8586

**Report of Total Generation Payment:**

BUS NUMBER	GENERATION (MW)	LOCATIONAL SIGN PAYMENT (€)	POSTAGE STAMP PAYMENT (€)	TOTAL PAYMENT (€)
1	20	19170	57750	76920
2	50	62940	144380	207320
5	30	29130	86630	115760
TOTAL	100	111240	288760	400000