Structure of
Transmission Use of System Charges

1st October 2001 to 31st December 2002

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1 Introduction

This paper describes the structure of ESBNG's Transmission Use of System (TUoS) charging regime for the period 1st October 2001 to 31st December 2002. The tariffs presented in this document were approved by CER on 8th October 2001.

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 2002 amounts to approximately £147m. 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. Due to the expected under-recovery of revenue for the year 2001[1] the CER directed that the 2002 tariffs would also be charged to users for the three final months of 2001 in order to reduce this under-recovery amount.

It should be noted that the tariffs approved for the year 2002 have been derived consistent with the methodology used to derive year 2000 tariffs. However, given that the costs associated with the transmission business have increased significantly from approximately £108m in 2000 to approximately £147m in 2002, the absolute value of the various tariffs by category have increased[2]. In addition to costs associated with the transmission business, the TUoS structure for 2002 is also designed to recover costs incurred in providing capacity margin, as instructed by the CER.

The structure of this document is as follows. Section 2 outlines the revenue requirement as approved by the CER for the year 2002 and provides a breakdown of the proportions recovered from generation and demand users, by cost category. A description of the various charges that apply to demand users is provided in section 2. Similarly, section 3 provides a detailed description of the generation tariff structure.
In the design of these tariffs the total amount recovered from the interconnector is not explicitly taken into account, as the amount recovered from interconnector flows is determined by the auctioning process. However, any revenue recovered from interconnector flows is used to off-set Use-of-System costs. A description of how capacity on the interconnector is allocated to market participants is provided in section 5.

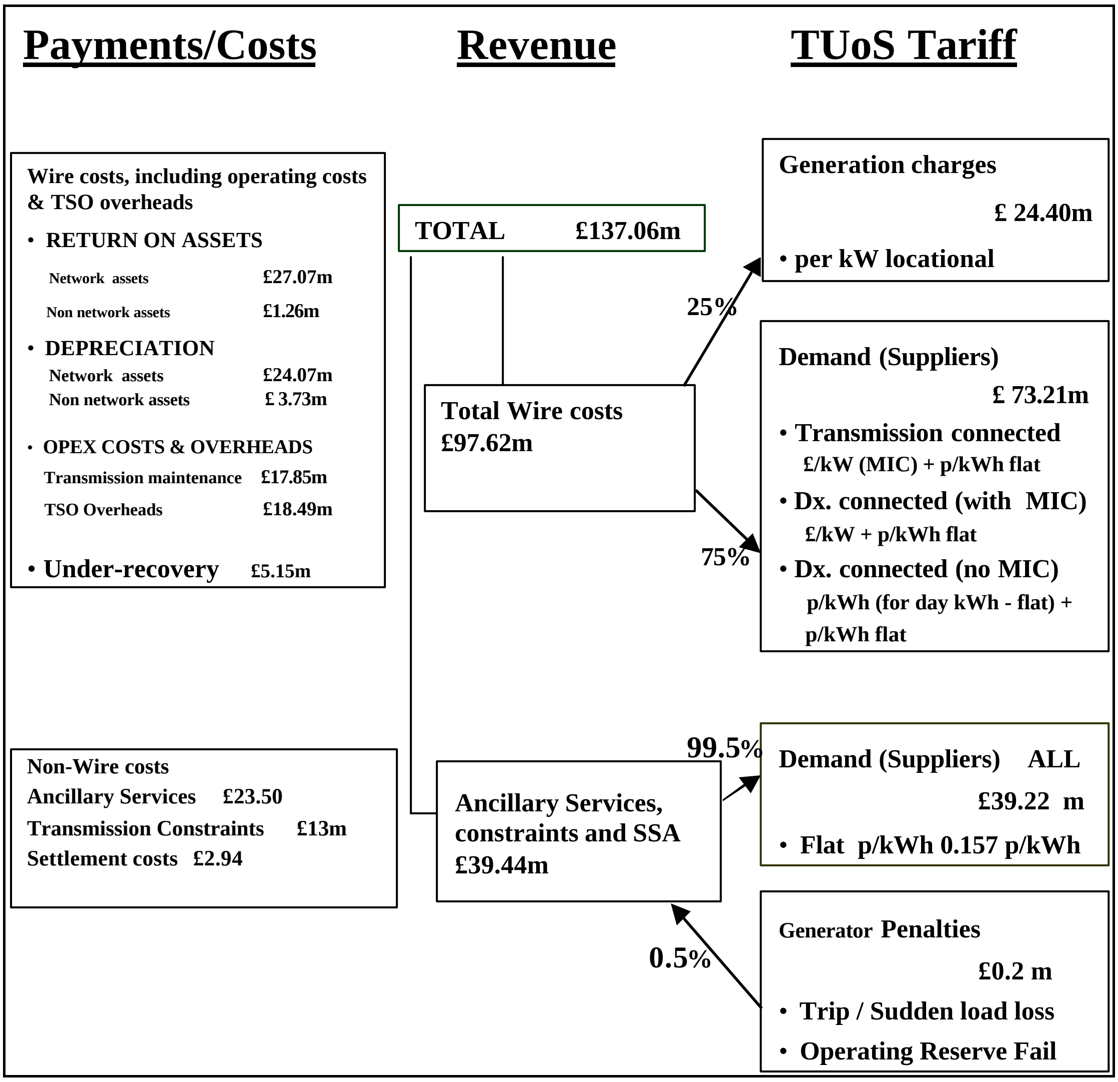
1 This under-recovery is mainly due to the fact that year 2000 tariffs were charged to users for the months of January to September of 2001.
2 As the aim of this document is provide a detailed description of the TUoS tariff structure, the reasons for the increase in transmission related costs are not discussed. However, in tandem with this document ESBNG have published a separate document outlining the tariff increases by category and explaining the reasons for these increases.

2 *Revenue requirement, 2002*

Figure 1 provides an overview of the total revenue requirement as allowed by CER for the year 2002 (in constant year 2000 terms), broken into the different cost components. As illustrated, the total revenue allowed to operate the transmission system for year 2002 is £137.06m. This consists of "wires" related costs, (which includes costs associated with deprecation, rate of return, transmission maintenance, capital expenditure and National Grid's operating expenditure costs) totalling £97.62m, and "non-wires" (which includes costs associated with Ancillary Services, Constraints and SSA on going costs) totalling £39.44m.

Costs associated with the transmission business are recovered from both demand and generation users. As shown in Figure 1, 25% of the wires related costs are recovered from generation and the remaining 75% from demand users. All non-wires related costs, with the exception of revenue received from generation trip payments, is recovered from demand users.

Figure 1: Transmission Revenue Requirement for year 2002 (real 2000 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: which provides service to suppliers serving customers connected directly to the transmission system.

(2) Tariff Schedule DTS-D1: which provides service 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: which provides service to suppliers serving all other *customers connected to the distribution system (including Green customers) who are* not served under the other tariff schedules noted above.

Each of these demand categories pays the following transmission related charges:

· *Network Charges (i.e. related to recovery of wires costs):* for the use of the transmission system infrastructure for the transportation of electricity in Ireland. As discussed in section 3, 75% of the total wires related costs are recovered from demand users.

· *System Services Charges (i.e. related to the recovery of non-wires costs):* 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[3]. This is considered appropriate as the transmission network is primarily a fixed cost that, while designed to meet system "coincident peak"[4] at its core, must also be designed to meet the "non-coincident peak" at its extremities. This approach is favoured over more traditional methods of

[3] 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).

[4] Within system planning criteria.

peak demand charging such as the Triad (as, for example, used by NGC), Pentad, or other coincident peak charging methods as it more properly reflects cost causation[5].

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 Transmission 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[6] 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[7] 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.

From opening of the energy market in February 2000, it was not 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 was not available. Therefore these customers are charged on the basis of the DTS-D2 tariff, as a proxy for the DTS-D1 tariff. Since February 2000, information has become available for some of these customers on a phased basis. 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[8] 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

[5] The remaining 40% is recovered on a variable, per MWh, basis (i.e. Network Transfer Charge)
[6] See ESBNG's *Statement of Charges* for description.
[7] See appendix 1 of this document for more details on application of distribution loss factors.
[8] PES Demand is calculated on residual basis i.e.in any given settlement period the total PES demand isderived by subtracting total demand total demand of eligible and green customers from total system generation, adjusted to take account of transmission losses.

Day Hours[9]. Day Hour Recovery is considered an effective proxy for having MIC values for all DTS-D2 customers[9].

Network Capacity Charge for 2002 (by user class)

Based on the CER's allowed revenue for 2002, and based on a forecast of the sum of the total MIC's for DTS-T and DTS-D1 and daytime energy consumed for user class DTS-D2, Table 1 provides Network Capacity Charges for each of these customer classes. For comparative purposes we have included the corresponding year 2000 tariffs.

Table 1: Network capacity charge in Euro, by user class

User class	Capacity charge, 2000	Capacity charge, 2002
DTS-T	€782.77/MW/month	€1,182.2235/MW/month
DTS-D1	€699.79/MW/month	€1,054.4214/MW/month
DTS-D2	€2.48/MWh	€3.9108/MWh

Unauthorised capacity charge (applies to DTS-T and DTS-D1 users)

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 capacity charge is applicable to demand users that exceed their MIC's. This charge has not been levied to date as ESBNG have given users time to make the transition to the current tariff regime. This charge will however come into effect from July 2002 onwards.

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 2002, Table 2 provides the Network Transfer Charge for the period, which is the same for all 3 classes of demand customer[11]. The year 2000 corresponding tariff provided below is included for comparative purposes.

Table 2: Network Transfer charge in Euro

Year	Tariff rate
2000	€1.13/MWh
2002	€1.7621/MWh

[9] Day Hours being 08:00 to 23:00 inclusive all days.
[10] See footnote 11

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. Based on year 2002 projections of system services costs and energy consumption. Table 3 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).

Table 3: System Services Charge

Year	Tariff rate
2000	€1.99MWh
2002	€2.3610MWh

3.3 *Capacity Margin Charge*

A specific charge designed to recover costs associated with the capacity margin has been introduced in this period, as directed by the CER. 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 €2.0996/MWh for the year 2002 for energy consumed during day-time hours[12].

11 It should however be noted that a users metered energy is adjusted to take account of distribution losses. A detailed explanation of how the distribution loss factors are applied in deriving the metered energy value is provided in Appendix 1 of this document.

4 Generation Transmission Service

As discussed in section 2, of the total allocation of network related costs, 25% is allocated to generation users. This cost is recovered from generation on a locational basis.

4.1 Generation locational charges

Generators connected directly to the transmission system or indirectly via the distribution system[13] 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 4 provides firm generation tariffs for the year 2002. A detailed explanation of this methodology used to derive these charges is provided in Appendix 2 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 is not eligible to pay the locational Network Capacity Charge. Embedded generators above this threshold pay transmission use of system charges.

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 Treatment of emergency generation

Emergency generation is treated on the same basis as wind generation. As emergency generation does not offset future transmission investment, the minimum charge applicable to wind generation is zero.

[13] As discussed in section 4.1.1 embedded generators below the 10MW threshold are not eligible to pay this charge.

Table 4: Generation locational charges, Oct. 2001 to Dec. 2002

Station	Units	Capacity	Network Capacity Charge Rate £/MW/month	Equivalent £/kW/year	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
Aghada	AD1, AT1, AT2, AT4	528.0 MW	**£504.17**	£6.0500	**€640.16**	€7.6819
Ardnacrusha	AA1,AA2 AA3,AA4	91.5 MW	**£18.32**	£0.2198	**€23.26**	€0.2791
Bellacorick	BK1,BK2	36.8 MW	**-£570.97**	-£6.8516	**-€724.98**	-€8.6997
Edenderry Power		117.6 MW	**£388.58**	£4.6630	**€493.40**	€5.9208
Erne	ER1,ER2	45.0 MW	**-£924.88**	-£11.0985	**-€1,174.35**	-€14.0922
Erne	ER3,ER4	20.0 MW	**-£901.54**	-£10.8185	**-€1,144.72**	-€13.7367
Golagh	GOW	15.0 MW	**£0.00**	£0.0000	**€0.00**	€0.0000
Great Island	GI1,GI2	114.0 MW	**£121.10**	£1.4532	**€153.77**	€1.8452
Great Island	GI3	112.0 MW	**£223.88**	£2.6865	**€284.26**	€3.4112
Irishtown		400.0 MW	**£441.06**	£5.2927	**€560.03**	€6.7203
Lanesboro	LA2,LA3	77.5 MW	**-£360.57**	-£4.3268	**-€457.83**	-€5.4939
Lee	LE3	8.0 MW	**£214.78**	£2.5774	**€272.72**	€3.2726
Lee	LE1,LE2	19.0 MW	**£199.97**	£2.3996	**€253.91**	€3.0469
Liffey	LI1,LI2	30.0 MW	**£367.45**	£4.4094	**€466.57**	€5.5988
MARIG1	MR1,MRT	112.3 MW	**£304.46**	£3.6535	**€386.58**	€4.6390
Moneypoint	MP1,MP2, MP3	862.5 MW	**£732.20**	£8.7864	**€929.70**	€11.1564
Northwall	NW1,NW2, NW3	44.0 MW	**£110.08**	£1.3209	**€139.77**	€1.6772
Northwall	NW4,NW5	227.0 MW	**£567.32**	£6.8078	**€720.34**	€8.6441
Poolbeg	PB1,PB2, PB3	486.0 MW	**£753.44**	£9.0413	**€956.67**	€11.4801
Poolbeg	PB4,PB5, PB6	457.0 MW	**£441.28**	£5.2954	**€560.31**	€6.7238
Rhode	RH3	37.0 MW	**-£67.33**	-£0.8079	**-€85.49**	-€1.0258
Shannonbridge	SH1	37.0 MW	**-£66.25**	-£0.7950	**-€84.12**	-€1.0094
Shannonbridge	SH2,SH3	77.5 MW	**-£25.89**	-£0.3107	**-€32.88**	-€0.3945
TARBG1	TB1,TB2	114.0 MW	**£492.04**	£5.9045	**€624.76**	€7.4972
TARBG3	TB3,TB4	481.4 MW	**£516.38**	£6.1966	**€655.67**	€7.8681
Turl_Hil	TH1,TH2 TH3,TH4	292.0 MW	**£565.61**	£6.7873	**€718.17**	€8.6181

4.5 *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 shows the charges per MW of trip output in excess of 100MW which generators will incur, for the year 2002. These charges are year 2000 charges adjusted for 2 years inflation at a rate of 3.5% (as instructed by the CER).

Table 5: Unit Trip Payments

Description	Amount
System Services Direct Trip Charge	€1.0881/MW
System Services Fast wind-down charge	€0.5441/MW

4.6 Volatility: Generation tariffs

The main objective of the reverse MW-mile methodology it 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 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 to a location. ESBNG believes that suitable mechanism should be introduced to reduce potential volatility. ESBNG will issue a consultation document on this issue in the near future.

ESBNG also proposes to give assistance to current and prospective new generators by publishing indicative tariffs for future years, under a range of network development scenarios (to be published, for example, in the Forecast Statement). Future tariffs proposed in this manner would be, of course, indicative only and siting decisions remain a matter for the generator.

4.7 Non firm transmission access

Based on the outcome of the discussions on the issue of "firm" access arrangements generators connecting to the transmission system may receive non-firm financial access for at least part of its output prior to the 'deemed' deep connection date. ESBNG is currently considering how best to charge connecting generators for non-firm access, and will present proposals to the CER in the near future.

5 Interconnector Transmission Service

Capacity on the South-North Interconnector is allocated to interested parties using an annual auction process. This process has been used to allocate Interconnector capacity since April 2000. In February 2001, 50 MW of Interconnector export capacity was auctioned by ESBNG for the period 01 April 2001 to 31 March 2002. Capacity that was not sold as part of this auction (totalling 10MWs) can be bought on a daily basis[14]. Receipts from the interconnector are used towards offsetting TUoS allowed revenue.

Details of the auction for the period 01 April 2002 to 31 March 2003 will be available on our website (www.eirgrid.com) over the coming weeks. Interconnector capacity form South to North is expected to be auctioned early in 2002.

[14] It should be noted that interconnector allocated capacity is non firm, i.e. parties are not compensated in the event that the allocated capacity is not available at any given time.

6 Other Issues

6.1 Treatment of Autoproducers

On 15 November, 2000, the CER published a consultation paper addressing the issue of how autoproducers should be treated in the transmission charging regime. As part of this consultation process ESBNG responded to this document with a number of concerns. The CER is expected to make a decision on this issue in the near future.

6.2 Adjustment to tariff

For a limited number of reasons, which are not fully under the control of the TSO, transmission costs could be significantly higher than projected. This could result in a significantly negative cash position for the TSO, as the income stream for a particular period could be lower than outgoing costs. CER has agreed that if a situation were to arise assistance would be provided to the TSO.

Appendix 1: 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 kW-15avg/1000 kW/MW = 1.4 MW-15avg/4 MWh/MW-15avg = 0.35 MWh
1200 kW-15avg/1000 kW/MW = 1.2 MW-15avg/4 MWh/MW-15avg = 0.30 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

Voltage	Day	Night
220 kV	1	1
110220 kV	1	1
38 kV	1.018	1.015
LV	1.107	1.087
MV	1.05	1.041

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

Appendix 2: Tariff Calculation Example (Reverse MW-mile approach)

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

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.

(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.

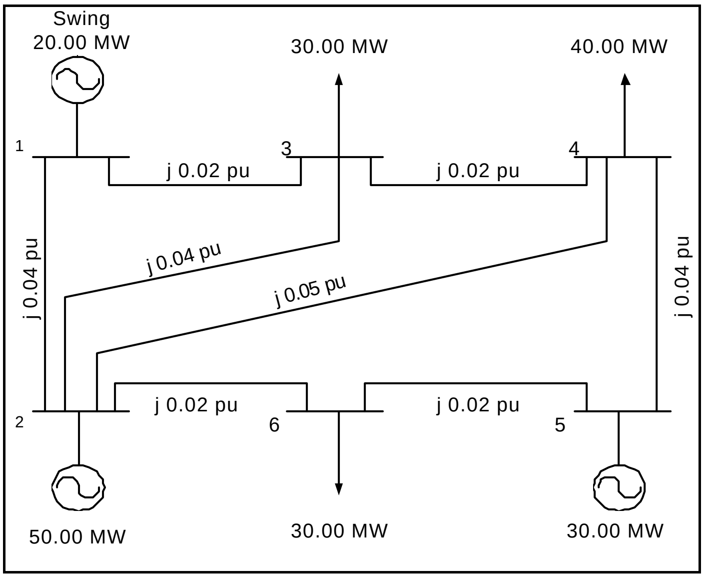


Figure 2 – System Example

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} = circuit flow (pu) – base 100 MVA

x_{ij} = circuit reactance (pu)

θ_{ij} = angle between the buses i and j (rad)

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

P_i = net injection = $P_{Gi} - P_{Li}$ (pu)

In matrix form:

$$P = B \cdot \theta \qquad B_{ij} = -x_{ij}^{-1} \qquad B_{ii} = \sum x_{ij}^{-1}$$

Using the numerical values of the system example:

$$P = B \cdot \theta$$
$$\begin{bmatrix} 0.20 \\ 0.50 \\ -0.30 \\ -0.40 \\ 0.30 \\ -0.30 \end{bmatrix} = \begin{bmatrix} 75 & -25 & -50 & 0 & 0 & 0 \\ -25 & 120 & -25 & -20 & 0 & -50 \\ -50 & -25 & 125 & -50 & 0 & 0 \\ 0 & -20 & -50 & 95 & -25 & 0 \\ 0 & 0 & 0 & -25 & 75 & -50 \\ 0 & -50 & 0 & 0 & -50 & 100 \end{bmatrix} \cdot \begin{bmatrix} ?_1 = 0 \\ ?_2 \\ ?_3 \\ ?_4 \\ ?_5 \\ ?_6 \end{bmatrix}$$

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 θ_{ij}, and after that the circuit flow P_{ij}, it is necessary to solve this equation:

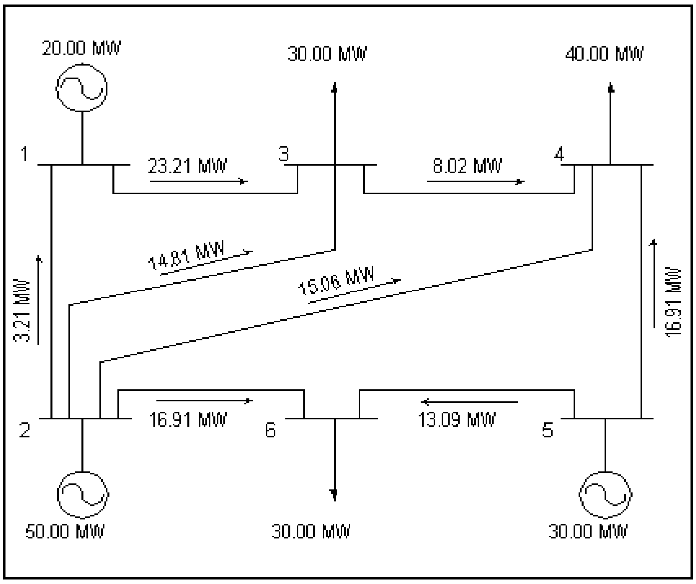
$$\theta = (B')^{-1} \cdot P$$

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

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.

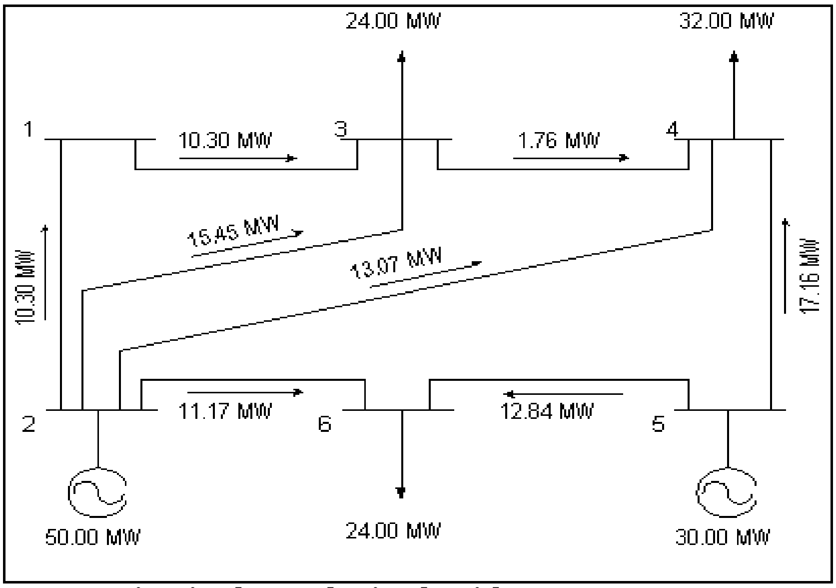
Generator at Bus 1 – Circuits Flow

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

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

$$P_{12} = -B_{12}\cdot\theta_{12} = 25\cdot(-4.1218\cdot 10^{-3}) = -0.1030\text{ pu} = -10.30\text{MW}$$
$$P_{13} = -B_{13}\cdot\theta_{13} = 50\cdot(2.0609\cdot 10^{-3}) = 0.1030\text{ pu} = 10.30\text{MW}$$
$$P_{23} = -B_{23}\cdot\theta_{23} = 25\cdot(6.1827\cdot 10^{-3}) = 0.1545\text{ pu} = 15.45\text{MW}$$
$$P_{24} = -B_{24}\cdot\theta_{24} = 20\cdot(6.5350\cdot 10^{-3}) = 0.1307\text{ pu} = 13.07\text{MW}$$
$$P_{26} = -B_{26}\cdot\theta_{26} = 50\cdot(2.2337\cdot 10^{-3}) = 0.1117\text{ pu} = 11.17\text{MW}$$
$$P_{34} = -B_{34}\cdot\theta_{34} = 50\cdot(0.3523\cdot 10^{-3}) = 0.0176\text{pu} = 1.76\text{MW}$$
$$P_{45} = -B_{45}\cdot\theta_{45} = 25\cdot(-6.8675\cdot 10^{-3}) = -0.1716\text{ pu} = -17.16\text{MW}$$
$$P_{56} = -B_{56}\cdot\theta_{56} = 50\cdot(2.5663\cdot 10^{-3}) = 0.1284\text{ pu} = 12.84\text{MW}$$



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

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

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

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

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

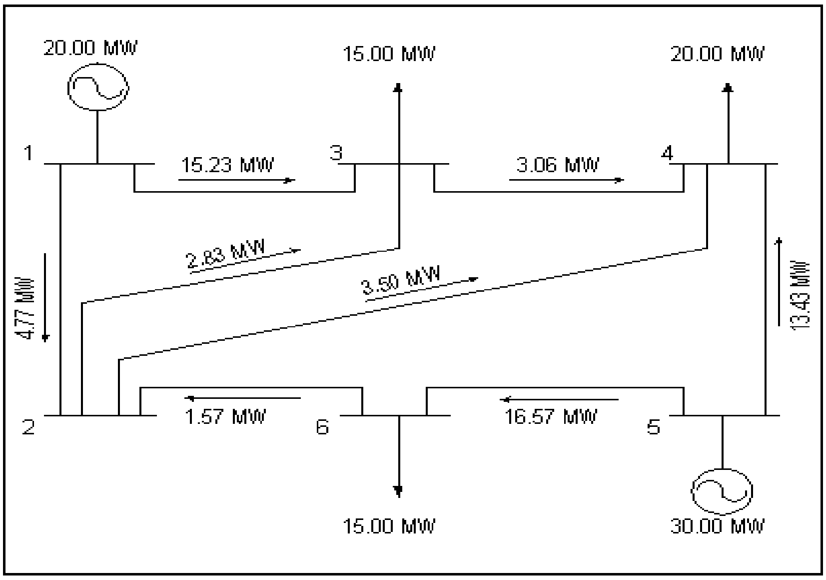
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (1.7490 \cdot 10^{-3}) = 0.0350\,\text{pu} = 3.50\,\text{MW}$$

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

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

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

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



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.

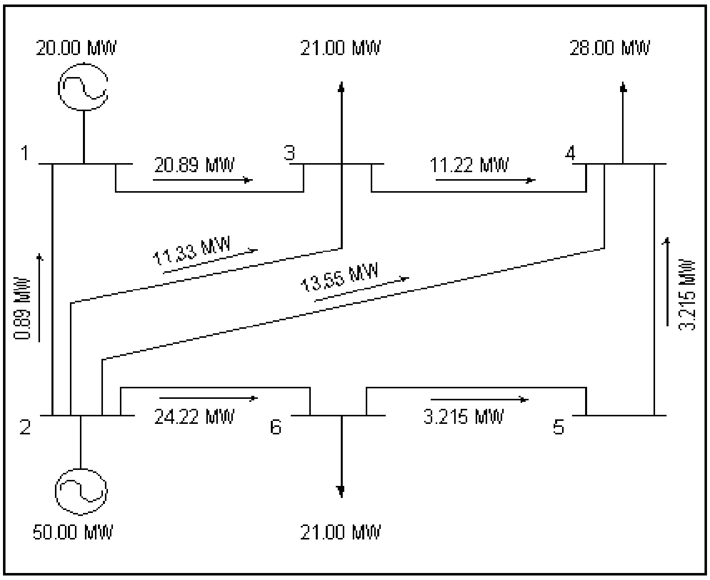
Generator at Bus 5 – Circuits Flow

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

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

$$P_{12} = -B_{12}\cdot\theta_{12} = 25\cdot(-0.3555\cdot 10^{-3}) = -0.0089\,\text{pu} = -0.89\text{MW}$$
$$P_{13} = -B_{13}\cdot\theta_{13} = 50\cdot(4.1778\cdot 10^{-3}) = 0.2089\,\text{pu} = 20.89\text{MW}$$
$$P_{23} = -B_{23}\cdot\theta_{23} = 25\cdot(4.5333\cdot 10^{-3}) = 0.1133\,\text{pu} = 11.33\text{MW}$$
$$P_{24} = -B_{24}\cdot\theta_{24} = 20\cdot(6.7778\cdot 10^{-3}) = 0.1355\,\text{pu} = 13.55\text{MW}$$
$$P_{26} = -B_{26}\cdot\theta_{26} = 50\cdot(4.8444\cdot 10^{-3}) = 0.2422\,\text{pu} = 24.22\text{MW}$$
$$P_{34} = -B_{34}\cdot\theta_{34} = 50\cdot(2.2444\cdot 10^{-3}) = 0.1122\,\text{pu} = 11.22\text{MW}$$
$$P_{45} = -B_{45}\cdot\theta_{45} = 25\cdot(-1.2889\cdot 10^{-3}) = -0.03215\,\text{pu} = -3.215\text{MW}$$
$$P_{56} = -B_{56}\cdot\theta_{56} = 50\cdot(-0.6444\cdot 10^{-3}) = -0.03215\,\text{pu} = -3.215\text{MW}$$



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

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

c_k = cost of circuit k
k_k = capacity of circuit k
$w^1{}_k$ = circuit flow caused by generator 1 on circuit k
π_1 = locational tariff

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

$$R_1 = 19170.00\,(£)$$

$$p_1 = \frac{R_1}{PG_1} = \frac{19.17 \cdot 10^3 (£)}{20 \cdot 10^3 KW} = 0.9585 (£) / KW$$

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
				TOTAL	62940.00

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

c_k = cost of circuit k
k_k = capacity of circuit k
w^2_k = circuit flow caused by generator 2 on circuit k
π_2 = locational sign tariff

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

$$R_2 = 62940 (£)$$

$$p_2 = \frac{R_2}{PG_2} = \frac{62.94 \cdot 10^3 (£)}{50 \cdot 10^3 KW} = 1.2588 (£) / KW$$

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
				TOTAL	29130.00

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

c_k = cost of circuit k
k_k = capacity of circuit k
$w^5{}_k$ = circuit flow caused by generator 5 on circuit k
π_5 = locational sign tariff

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

$$R_5 = 29130(£)$$

$$p_5 = \frac{R_5}{\overline{PG_5}} = \frac{29.13 \cdot 10^3 (£)}{30 \cdot 10^3 KW} = 0.9710(£)/KW$$

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:

Transmission Revenue: 8 circuits x $50 \cdot 10^3$ (£) = $400 \cdot 10^3$ (£)

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: $\Delta = \dfrac{288.76 \cdot 10^3 (£)}{100 \cdot 10^3 KW} = 2.8876(£)/KW$

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