MW-Mile Charging Methodology for Wheeling Transaction

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By

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DEDICATION

TO

MY BELOVED FATHER

WHO DID NOT LIVE LONG ENOUGH TO SEE MY ACHIEVEMENTS

GLOSSARY OF TERMS

AC	Alternating Current
ACS	Average Cold Spell
BB	Branch Based transmission service
BSC	Balancing and Settlement Code
BSUoS	Balancing Services Use of System
CAISO	California ISO
CIS	Chilean Central Interconnected System
DC	Direct Current
DCLF	DC Load Flow
EC	Embedded Cost
ERCOT	Electric Reliability Council of Texas (USA)
ESBNG	Electricity Supply Board National Grid (Republic Ireland)
FTR	Fixed Transmission Rights. FTR is a purchased right that can hedge congestion charges on constrained transmission paths. It provides FTR owners with a right to transfer an amount of power over a constrained transmission path for a fixed price.
GGDF	Generalised Generation Distribution Factor
GLDF	Generalised Load Distribution Factor
GSDF	Generalised Shift Distribution Factor
ICRP	Investment Cost Related Pricing
ISO	Independent System Operator. ISO is central entity to have emerged in all deregulated markets with the responsibility of ensuring system security and reliability, fair and equitable transmission tariffs and providing for other system services.
NE-ISO	New England ISO (USA)
JDF	Justified Distribution Factor
LUF	Line Utilisation Factor
LMP	Locational Marginal Price
LRMC	Long Run Marginal Cost

LRIC	Long Run Incremental Cost
MP	Marginal Price
NGC	National Grid Company (UK)
OPF	Optimal Power Flow
PFD	Power Flow Decomposition
PJM	Pennsylvania, Jersey, Maryland Power Pool (USA)
PTDF	Power Transfer Distribution Factor
PTP	Point-to-Point transmission service
PUCT	Public Utility Commission of Texas
PX	Power Exchange. PX is a new marketplace to trade energy and other services in the competitive manner
RPAF	Reactive Power Adjustment Factor
RPI	Retail Price Index
SHETL	Scottish Hydro Electric Transmission Limited (UK)
SPP	Southwest Power Pool, Inc.(USA)
SPTL	Scottish Power Transmission Limited (UK)
SRIC	Short Run Incremental Cost
SRMC	Short Run Marginal Cost
TCOS	Transmission Cost of Service
TNUoS	Transmission Use of System
TO	Transmission Owner
TRR	Transmission Revenue Requirement
VAMM	Vector Absolute Megawatt Mile

ABSTRACT

Deregulation of the electric utility industry has taken place in many countries. This resulted in the unbundling of the vertically integrated utilities into separate generation, transmission and distribution businesses. Since then, the pricing of the use of transmission system has become one of the major issues. The issue concerns the way the cost of transmission services is satisfactorily allocated among the involved parties. In the context of the transmission utilities, the issue is how the cost of transmission service can be recovered while in the customers of transmission services point of view, the issue is how such services can be offered at the most reasonable price. Several strategies for pricing the use of transmission services have been proposed but there is no clear evidence on which one is better in providing adequate economic signal to the different parties.

This thesis introduces a new approach called Negative Flow Sharing Approach to allocate the wheeling transaction charges among the users in transmission services. The proposed approach was developed using the properties of MW-mile method but taking into consideration the economic benefits of both trading parties through analysing their shares in negative power flow or counter flow. This approach is incorporated with the Justified Distribution Factor and an Incremental Absolute Approach to form a better wheeling charge allocation scheme that can overcome the problem that arises due to the allocation method, identification of counterflow users and revenue reconciliation of transmission services.

Four case studies which are based on the 5 bus system, 9 bus system, IEEE-14 bus system and the 6 bus system were used in order to evaluate its concept and application. This thesis concludes with discussions on the case studies results by highlighting the merit of the proposed approach over the existing MW-mile approaches in providing sufficient return revenue to the transmission owner as well as a fair charge to the transmission user regardless of transaction arrangements and locations.

CHAPTER 1

INTRODUCTION

1.1 Introduction

Electric utility industry in many countries has been deregulated to further increase its competitiveness, such as efficiency and cost reduction in power generation, transmission and distribution. With deregulation, this industry would work in three major independent businesses, i.e. generation, transmission and distribution respectively. Among these, a transmission company plays a major role since it involves in the determining of charges due to the wheeling transactions. In the past, wheeling transactions have accounted for a small portion of the overall transmission network capacity usage. However, recent trends towards unbundling of electric services have resulted in renewed interest in pricing of transmission services, particularly as it relates to wheeling transactions [4].

Wheeling transaction is defined as the transmission of electric power for other entity(ies) by a utility that neither generates nor intends to use the power as a system resource for meeting its own native load. The receipt and delivery of the wheeled power must be simultaneous. At least three parties are involved in a wheeling transaction: a seller, a buyer and one or more wheeling utilities that transmit the power from the seller to the buyer. The third party is paid for the use of its network.

Many methods have been used or proposed to evaluate the costs of transmission transactions or so called wheeling transactions. Most methods attempt at least two basic measurements: the amount of transmission capacity used and the per-unit cost of transmission capacity [5]. These methods can be classified into one of these categories; embedded cost, incremental or marginal cost. The concept of these methods has been discussed by some of the authors [1,3,5,6] to show their ability to provide reasonable economic signal. Economic theory stipulates that goods and services should be charged on the marginal cost basis. It has been found, however, that the short-run marginal cost (SRMC) pricing of transmission service is highly volatile, fails to recover the total incurred networks costs and provides perverse economic signals for the transmission company [7,8]. On the other hand, establishing the long-run marginal cost (LRMC) pricing is a formidable task and depends on a number of assumptions about costs and scenarios of expansion [6]. For these reasons, the embedded cost methods are used commonly throughout the utility industry. This method offered several benefits, i.e. practical and fair to all parties and easy to measure and provides an adequate remuneration of transmission systems. However it also has some drawbacks, i.e. it does not reflect the degree to which these facilities are over-utilised or under-utilised and does not provide efficient means to allocate resources to relieve constrained transmission capacity.

There are four types of embedded cost methods extensively used to allocate the transmission transaction cost namely, postage stamp method, contract path method, distance based MW-mile method and power flow based MW-mile method.

In postage stamp method, the transmission charges are allocated based on an average embedded cost and the magnitude of transacted power. This method is popular because of its simplicity, however it ignores the actual system power flows. The contract path method, on the other hand, based upon assumption that the transaction is confined to flow along a specified electricity continuous path throughout the wheeling company's transmission system. The embedded capital costs, correspondingly are limited to those facilities lie along this assumed path. A drawback with the method is that the actual path taken by the transaction does not flow only along the specified contract path but also involves the use of other transmission paths outside the contracted one. As a result it affect the cost of transmission system outside the contract path. The distance based MW-mile method allocates the charges based on magnitude of transacted power and the airline distance between the point of delivery and receipt. This method has also found to give incorrect economic signal to the wheeling participant. The airline distance does not indicate the actual transmission facilities involved in the transaction.

Power flow based MW-mile method is more commonly widely used since it has been shown to be more reflective of actual usage of the transmission system in allocating the transmission cost. This method allocates the charges for each wheeling participant based on the extent of use of transmission facilities by these transactions

[4,9,10,11,12]. These allocated charges are then added up over all transmission facilities to evaluate the total price for use of transmission system. Unlike the contract path and the postage stamp methods, this method considers the changes in MW flows due to the wheeling in all transmission lines of the wheeling companies, and the line length in miles. Two power flows executed successively, with and without the wheeling, yield the changes in MW flows in all transmission lines.

There are three different MW-mile approaches that can be used to determine the wheeling charges for a particular transaction, and these are classified as net, absolute and positive only approaches respectively [13-14]. Based on these three approaches, further modified methods such as Modulus Method, Zero Counterflow Method, Dominant Flow Method and other associated methods have been proposed to allocate the cost of the use of the system network as addressed in [1,15,16,17]. However, the MW-mile method based on absolute approach is the most popular among the transmission utilities since it promises sufficient revenue [18,19]. This approach has contended by the transmission users because it ignores the contribution of users for negative power flow or counter flow [19]. On the other hand, the other two approaches may not be easier for the transmission owner to accept because they could cause a transmission owner unable to receive appropriate revenue return if the transactions coincidently create many counter flows across the transmission network. It can be noticed that the reason why there is no such an agreement among the trading parties for the acceptance of the aforementioned approaches is because the benefit of a counterflow is received once only by one trading party. Therefore an alternative approach is required to be developed so that the benefit of the counterflow could be shared among the trading parties.

Meanwhile, the allocation method used to identify the contribution of individual generators and loads to line flows and the real power transfers between individual generators and loads is another important issue in wheeling transaction since it reflects the way the cost of transmission services is satisfactorily allocated among the trading parties. Different allocation methods have been proposed in recent years. A novel, topological distribution factor method which determines the share, as opposed to the impact of a particular generator or a load in every line flow is presented in

[20], which is based on tracing method. Although this method is conceptually very simple but it requires inverting a sparse matrix of the rank equal to the number of network nodes. In [21], another tracing method is presented which introduces new concepts such as domain, common, link and state graph and is suitable for large-scale power system applications. Furthermore in [22] graph theory is applied to solve the problem of power flow tracing with the proof of two lemmas to show the feasible condition for the suggested method which is also complex in procedure. However, as far as the allocation method is concerned, there are no clear declaration and proof of the implementation of these methods in the transmission utilities.

The only allocation method that is presently in widespread use in transmission utilities is the power transfer distribution factor (PTDF) [23,24,25 26]. This factor is also known as a shift factor, impedance factor or generalised shift distribution factor (GSDF). Unlike the topological distribution factor which is based on topological analysis of network flows and represents the share of a particular generation in the total line flow, the PTDF represents the impact of a particular generation on the line flow. This distribution factor which is based on DC power flow is developed by taking into account the physical parameters, i.e. reactance of the transmission network and hence is capable of allocating MW flows to lines or transformers with "reasonable" accuracy [27]. However it is dependent on the location of the reference bus, i.e. different reference bus yields different distribution factors. This could cost the time in generating the new distribution factors if users are allowed to use different reference buses to accommodate their transactions. The shortcoming of the PTDF that varies according to reference bus however has successfully been overcome with the new developed distribution factor which is known as Justified Distribution Factor (JDF). The development of this factor is used to implement the congestion curtailment in bilateral tradings [28]. In this thesis, the application of JDF is extended to estimate the contribution of the transmission user to line flows as well as identifying the counterflow lines.

This thesis aims to improve the present MW-mile approaches used for allocating wheeling transaction charges among the users in transmission services. The proposed approach is developed using the properties of the MW-mile method but taking into consideration the economic benefits of both trading parties through analysing their shares in negative power flow or counter flow. This approach is incorporated with the Justified Distribution Factor and an Incremental Absolute Approach to form a better wheeling charge allocation scheme. The results show that the proposed approach has merit over the existing MW-mile approaches in the context of revenue reconciliation of transmission services regardless of transaction arrangements and locations. The profit sharing concept introduced in the proposed approach provides a better economic signal in allocating charges for counter flow lines, which could benefit trading parties.

1.2 Contribution of the Thesis

The main original contributions of this thesis are as follows:

1) The development of a negative flow sharing approach to solve the counterflow pricing problem. This approach uses the profit sharing concept to distribute the benefit of the negative flow or counter flow created in the line flow to both the transmission owner and user. Based on a profit sharing factor r that has been set in the trading, the share for the charge due to counterflow can be calculated. The proposed approach is capable of allocating the wheeling charges for both single and multiple simultaneous transactions.
2) Introduce the use of Justified Distribution Factor in estimating the contribution of users in the line power flows as well as identifying the counterflow lines. It is capable of dealing with multi reference bus users.
3) Introduce the use of incremental absolute approach in determining the power flow impact. Unlike marginal approach, this approach, which considers the difference of power flow irrespective of the flow direction successfully recognised the actual amount of power flow that should be rewarded to a user due to the counterflow.
4) Based on the combination of 1), 2) and 3) above, a new wheeling charge allocation scheme is formed to provide a better and fair charge for both parties involved in the trading.

5) The thesis contains a review, supplemented by work examples, of the transmission wheeling charge in the United Kingdom, Republic of Ireland and the United States of America.

1.3 Organisation of the Thesis

This thesis consists of six chapters. Chapter 2 deals with the issues of cost and pricing of transmission services under deregulated environment. This chapter will discuss basic structure of transmission services that cover the type of services, objectives and the methodologies used to recover the costs of transmission. It also discusses several alternatives of the allocation methods that can be used to evaluate the usage of the transmission services and the pricing methods that is currently used or under consideration in transmission services. Issue of revenue reconciliation of transmission services and its allocation options are addressed at the end of the chapter.

In Chapter 3 the issues of use of system charges will be discussed, as it is related to the pricing of the transmission services. It focuses on UK's use of system charges methodologies, which covers the conceptual, the components associated with the charges and the charge allocation. This chapter also discusses the phenomena of wheeling and the cost associated with wheeling to highlight the significant of the wheeling charges as the components of use of system charges. The current wheeling charge methodology used by transmission utilities in the United Kingdom, Republic of Ireland and the United States of America are presented in this chapter. An example will be used to illustrate each of this wheeling charge methodology.

Chapter 4 describes the methodology and the mathematical model of the proposed approach for the use of system charges; wheeling charges. It focuses on the concept and formulation of the MW-mile methodology as it is related to the development of the proposed approach. This chapter will also discuss the methodology and the mathematical model of the Justified Distribution Factor and Incremental Absolute Approach which is incorporated into the proposed approach. An example and flow chart will be used to describe the significant of the proposed approach in providing a better wheeling charge allocation scheme.

Chapter 5 presents the simulation results of wheeling charges based on the proposed approach developed in Chapter 4. The proposed approach is tested for different transaction arrangements and locations in order to evaluate its capability to provide sufficient revenue return to the transmission owner as well as a fair charge to the transmission user. Four case studies which are based on the 5 bus system, 9 bus system, IEEE-14 bus system and the 6 bus system will be used for comparison purposes.

Finally, Chapter 6 presents the conclusion of the research work in the thesis and some recommendations for future research work. The data for the different bus systems, the distribution factors matrixes that have been used to estimate the line flows and the results for some case studies are given in the appendices.

1.4 Publications

The following publications have been accepted or are under review as a result of the research work.

1. K.L.Lo and M.Y.Hassan, "Positive and Negative Aspects of MW-Mile Method for Costing Transmission Transaction",37th International Universities Power Engineering Conference(UPEC), United Kingdom, Vol.1, pp. 358-362, Sept 2002.

2. K.L.Lo and M.Y. Hassan, "Revenue Reconciliation of Transmission Services using Negative Flow Sharing Approach", The 6th International Power Engineering Conference, IPEC 2003, Singapore, Vol. 1, pp. 521-526, Nov 2003.

3. K.L.Lo and M.Y. Hassan, "Assessment of MW-Mile Method for Pricing Transmission Services – A Negative Flow Sharing Approach", Submitted to IEE Proc. Gener. Transm. Distri., 2004.

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CHAPTER 2

THE COST AND PRICING OF TRANSMISSION SERVICES

2.1 Introduction

The electric utility industry throughout the world has been undergoing significant changes due to the process of deregulation. It is changing from its traditional model managed under vertically integrated monopoly to a more market dependent business. The level of this process varies from one country to another with the main objectives being able to provide higher operational efficiency and lower energy costs. For the industrialized countries, this process has progressed rapidly with the emergence of competition not only in the area of electricity generation, but also extends to other markets such as the retail domestic consumers. On the other hand, developing countries are trying to attract much needed capital investment for their power sector expansion activities, particularly for the generating capacity through the involvement of the private sector.

Under the deregulation scheme, the electricity businesses have unbundled into three components: generation, transmission and distribution. The interaction among these components would be on pure commercial bases. In the case of transmission, transmission (wheeling) services represent unbundled services. Since then, the pricing of the transmission services has become one of the major issues. The pricing issue refers to the way the cost of transmission services is satisfactorily allocated among all involved participants, taking into account as accurately as possible the real impact of every transaction on the transmission system. The true cost of transmission services must be calculated and a pricing structure must be established which ensures the recovery of costs and the establishment of a valuable niche in the marketplace for transmission service utilities. Customers of transmission services want to evaluate their options to acquire such services at the most reasonable price.

This chapter deals with the issues of cost and pricing of transmission services under deregulated environment. This chapter will first discuss basic structure of transmission service, which covers the type of services, objectives and cost element related to the service. It will then discuss the methodologies used to recover the costs of transmission services. This discussion will focus on the features of each methodology in term of their capability in recovering the transmission service costs.

This chapter will also look at several alternatives of the allocation methods that can be used to evaluate the usage of the transmission services and followed by the discussion of pricing methods that is currently used or under consideration in transmission services. The concept of revenue reconciliation of transmission services and its allocation options are presented at the end of this chapter.

2.2 Transmission Services

In the vertically integrated industry, transmission service is seen as a complement to generation. The generation of power and the service of moving it from one node of the grid resources are planned and operated by the same entity. As a result, transmission costs, mainly consisting of investment costs, are considered common costs and are recovered under the current cost-based regulatory structure through a single bundled price of electricity, which is based on average costs. Transmission pricing is not used as an active signal to shape the generation and consumption of electricity. However as the industry is moving toward full open access, the identification of the costs of transmission services provided by the transmission utility should be properly evaluated in order to provide and set prices for the use of transmission facilities to the market participants, in the fair manner.

Transmission services generally can be defined in two manners: point-to-point transmission services (PTP) and branch-based transmission services (BB) or network services. PTP transmission service is defined as the transmission of power between two nodes, the source node and the sink node or in other word the service is between specified delivery and receipt points. BB transmission service is defined as the transmission of power over each branch (transmission, line, transmission, etc). This service allows the transmission user a complete access to the system with no specification on the points of delivery or receipt, nor any additional charge for change of schedules [5].

For the PTP transmission services, the key issue is to calculate the cost of each type of service while the BB transmission services; the key issue is to determine the usage of each transaction of each branch. For both PTP transmission services and BB transmission services, the cost can be total cost, average cost, marginal cost and so on, which type of cost to calculate is determined by the pricing method adopted. Figure 2.1 illustrates the transmission services under the two definitions.

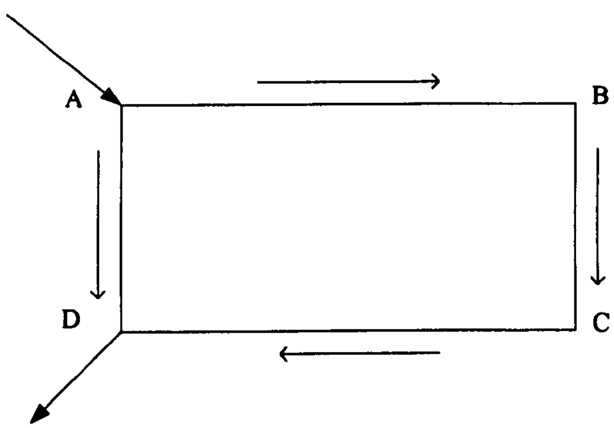

Figure 2.1 Two Types of Transmission Services

In the system, there are 4 nodes; A, B, C and D and 4 lines; AB, BC, CD and AD. There are 6 types of PTP transmission services, A-B, A-C, A-D, B-C, B-D and C-D, and 4 types of BB transmission services, AB, BC, CD and AD. If there is a transaction to transmit 1MW power from node A to node D, this transaction requires one type of PTP service, which is from A to D or 4 types of BB services, AB, BC, CD and AD. Hence the amount power required for PTP service, A to D service is

1MW. However the amount power for BB services are not so easy to determine especially when there are several transactions taking place.

In general, the costs arising from transmission services can be divided into several cost elements and can be classified as fixed costs and variable costs. These costs elements are;

Costs of construction, operation and maintenance of transmission network equipment. This is the major part of transmission costs. It comprises implicit costs, made up of the depreciation of the fixed assets, the finance charges and the allowed return on proprietary capital, as well as explicit costs. The construction cost is associated with the investment made in building the transmission network while the operation and maintenance costs are primarily labour costs associated with functions such as supervision and engineering, load dispatching, station expenses and maintenance of structures, station equipment and overhead.

Costs of losses. The costs of losses are the costs to recover the energy losses caused by the branch resistance. For this purpose, the network operators usually buy the energy from generating companies.

Congestion costs. The congestion costs are the out-of merit production costs due to the transmission constraints.

Costs of ancillary services. The costs of ancillary services are the costs of providing services to assure the security of power system operation and quality of electricity.

The costs of transmission network are mainly fixed costs, because transmission capacity cannot be adjusted in the short run and maintenance and operation costs are hardly dependent on the actual use of the system. On the hand, the costs of losses can be split into a smaller fixed part concerning constant or voltage-dependent losses, and a greater variable part concerning current-dependent losses. Meanwhile the short –term congestion (i.e. those do not concern network reinforcement) are exclusively variable costs because if the system were not used at all, there would not be any congestion. The costs of ancillary services are partly more or less fixed (voltage control; precautions for system restoration), partly variable (reactive power supply; metering and settlement) and partly of mixture nature (frequency control)

However, this thesis will focus the research on the development an approach that can be used for BB transmission service for recovering the transmission network costs, which will be presented in Chapter 4.

2.3 Objectives of Transmission Services Pricing

The main objective of transmission services pricing is to allocate all or part of the existing and new cost of transmission system to the users. However, the tariffs for transmission services are more often set by government regulations and are based on its policy directives. In addition of this, any transmission pricing strategy should seek to achieve the following goals [5]:

Recover costs: The tariff charged for use of transmission services must produce enough revenue to cover all the expenses made in investment, operation and maintenance of the transmission network, as well as provide a small (regulated) level of profit for the owners.

Encourage efficient use: The price structure should give incentives for using the transmission system efficiently. Efficient use could mean ensuring both, economic efficiency by maximising social benefits and technical efficiency by minimising losses.

Encourage efficient investment: The price structure and the way money is paid to the owners should provide an incentive for investment in new facilities, when and where they are needed.

Fair: Must be fair and equitable to all users.

Understandable: All users must be able to understand the pricing structure.

Workable: The pricing scheme should be implementable in the actual system.

These objectives are the most common to arise in the discussion of transmission pricing however in reality it is so difficult to achieve since the transmission services have some specific characteristics. From the pricing point of view, there are three main characteristics [6]:

The economies of scale: Costs exhibit economies of scale when long-run average costs fall as output increased. For transmission services, this is due to the bulky investment of transmission facilities. Since the long-run average cost falls as transmitted flow increases, the marginal cost is always lower than average cost. The highest possible welfare is achieved when a firm produces at the point where its price is equal to the marginal costs. But for transmission services, the transmission owner cannot recover its revenue requirement by purely based on marginal cost pricing since the marginal cost always lower than average cost. For this reason the economics have developed many methods to resolve this issue, which called revenue reconciliation such as Ramsey pricing, two –part tariff, etc. The Ramsey Pricing which has been described in Appendix G is the pricing method where the optimum prices are modified by an amount proportional to the demand elasticity. This modification usually causes the minimum loss in economic efficiency while ensuring the revenue recovery of the utility [34]. Meanwhile, the two-part tariff is a pricing method that can lead to relative high welfare subject to the breakeven constraint, and it is commonly used by many natural monopoly industries.

Non-linear of power flow functions: The most important characteristic of transmission service is the non-linearity of power flow function. That means, the branch flows are non-linear functions of node flows. This causes the difficulty to evaluate the effect of each transmission transaction on line flows. For this reason, the DC load flow analysis has been used by many transmission utilities in evaluating the power flow transaction.

Externality: When the activity of one entity (a person or a firm) directly affects the welfare of another in a way that is outside the market mechanism, this effect is called externality. The externality caused by loop flow or parallel flow, is another characteristic of transmission services. The changing of flow or voltage at any node will lead to the changing of flows or voltages at all other nodes in the network. The transmitting of power between any pair of nodes will affect the transmitting abilities between all other pair of nodes.

2.4 The Cost Component of Providing Transmission Services

The major components of the cost of transmission services that a utility incurs in order to fulfil the transmission contracts satisfactorily are operating cost, opportunity cost, reinforcement cost and existing system cost. The operating cost is the production that the company incurs for providing the service. The opportunity cost is the benefits unrealised due to operating constraint that caused by the transaction. The reinforcement cost includes the cost of all transmission reinforcement necessary to provide the service and the existing system cost is the cost associated to the existing facilities for providing transmission service. The sum of these four components generally resulted the total cost of transmission services is explained in more details in Sections 3.3.4.1, 3.3.4.2, 3.3.4.3 and 3.3.4.4 of Chapter 3.

The first three of these cost components (operating cost, opportunity cost and reinforcement cost) constitute what is commonly called the incremental cost of the transmission service. There are also some other terms used in the industry to refer to the components of the cost of a transmission service. These terms include Short-Run Incremental Cost to refer the operating cost and opportunity cost, Long-Run Incremental Cost to refer to operating cost, opportunity cost and reinforcement cost and Embedded Cost to refer to a portion of the existing cost.

Economists also use terms such as Marginal Cost for transmission service. This cost, which, refers to operating cost and opportunity cost have been proposed for pricing transmission services. Detailed description of these methodologies included its advantages and the limitation in order to recover the cost of transmission service is presented in the following section.

2.5 Recovering Cost of Transmission Service

In the context of recovering the cost of transmission services, the transmission utilities must have a means to charge for the transmission services rendered. This is to ensure that they are able to recover the transmission revenue requirement. Depending on the four components as mentioned above there are a variety of means of assessing these costs have been proposed which fall into three broad categories; marginal cost methods, incremental cost methods and embedded cost methods.

2.5.1 Marginal Cost

Marginal cost can be defined as the revenue requirements needed to pay for any new capacity on the transmission system. The facilities must be identified for all years across the life of the contracts for transmission service. The transmission service customer pays an allocated share of the cost for any new facilities that the transmission system requires. The allocation of marginal cost is done through the usage calculation [2].

Marginal cost can be Short-run Marginal Cost (SRMC) or Long-run Marginal Cost (LRMC). For uniform transmission services, which is defined as the transmission services in ideal deregulated competitive marketplace, SRMC is the least cost of providing an additional unit of the service on condition that the current network cannot be reinforced while LRMC is the least cost of providing an additional unit of the service on condition that the current network can be reinforced [6].

2.5.1.1 Short Run Marginal Cost

Short Run Marginal Cost (SRMC) is the cost of increasing (or decreasing) output to meet an increment (or decrement) in demand when capacity is fixed; or, if demand would exceed the level of capacity, it is the price necessary to ration demand so that it remains within existing capacity.

In the electricity business, the SRMC approach refers to operating cost and opportunity cost. Other costs such as reinforcement costs, capital costs of new transmission facilities needed to accommodate the transmission transaction are not included. The economic theory denotes that goods and services should be charged on the marginal cost basis.

SRMC accounts for congestion cost and reflects opportunity costs. This method allows congestion charges to increase as transmission capacity becomes over-utilised.

The Short-Run Marginal Cost of wheeling between two buses is defined as the difference in the costs of producing an additional megawatt at each bus. It is expressed in terms of partial derivatives [4]:

$$\text{marginal cost} = \left[\frac{\partial f_1}{\partial MW_1} - \frac{\partial f_2}{\partial MW_2} \right] \tag{2.1}$$

where:

f_1 introduction cost rate, £/hour at bus 1,

f_2 introduction cost, £/hour at bus 2,

MW_1 injection at bus 1 and

MW_2 injection at bus 2

or the general formula for SMRC wheeling rates is

$$\omega = \frac{\partial(\text{Wheeling Operation Cost of Utility})}{\partial(\text{Amount of Wheeled of Electricity})} \tag{2.2}$$

The quantities $\frac{df_1}{dMW_1}$ and $\frac{df_2}{dMW_2}$ are defined as the spot prices at bus 1 and bus 2 respectively.

These marginal costs are available from *OPFs*, which use partial derivatives to minimise the objective functions. If the objective function is the production cost the partial derivatives of the cost with respect to real power can be obtained for each bus in the system. The marginal cost of wheeling power between two buses is simply the difference between these partial derivates. For instance, the marginal cost calculation based on 14-bus system is shown below:

Bus 1

$$\frac{df_1}{dMW_1} = £\ 23.62/\text{MW hr}$$

This signifies that each MW of load at bus 1 will be supplied at the cost of £ 23.62/MW hr

Bus 14

$$\frac{df_{14}}{dMW_{14}} = £18.21/\text{MW hr}$$

This signifies that each MW injected at bus 14 displaces generation priced at £18.21/ MW hr. Thus, the marginal wheeling cost to bus 1 with respect to bus 14 is 23.62-18.21= £5.41/MW hr.

SRMC has been most popular due to its economic basis, that is, it can gives correct price signals to generators and loads for efficient location and operation. It also increases system efficiency as it provides information necessary for operation and expansion of the transmission network. However some limitations have been observed in its application to power transmission systems such as [7]:

- Results may be inadequate if the magnitude of each transaction is large (using derivative to predict entire charge).
- Needs forecast of marginal prices (less accurate as time goes out)
- Charges for transmission system are based on generation costs rather than its own costs
- Transmission charges increase with losses and constraints, result in need for regulation.
- Transmission revenues may be significantly smaller than actual costs to compensate for existing and future investments.
- The charges obtained may be highly volatile

Hence, SRMC prices may discourage the host utility from expanding its transmission system. In fact, should the host utility make any expansion in its transmission system, the SRMC prices will decrease dramatically the possibility of recovering transmission reinforcement costs [10].

2.5.1.2 Long Run Marginal Cost

The Long Run Marginal Cost (LRMC) usually refers to the costs of incremental production over a long period, including both variable and fixed costs and can be defined as the marginal cost of supplying an additional unit of energy when the installed capacity of the system is allowed to increase optimally in response to the marginal increase in demand [8].

This approach refers to operating cost, opportunity cost, and includes reinforcement costs, due to transmission expansion. In the LRMC, the network can be expanded to meet incremental use. The user is charged on the basis of the incremental investment and operating costs caused by their incremental use of the transmission network. The use of the LRMC pricing has gained some support due to economic aspects and price stability. Unlike SRMC, congestion costs are not a part of the calculation because capacity in the long run can be adjusted to provide the optimal quality of service. Accordingly, a time profile of long-run marginal cost would not fluctuate as much as short-run costs.

There are two broad approaches to determining charges by the LRMC methodology. The first one is the scenario-based approach. The network operators project specific transmission expansion plans based upon demand forecasts, generation expansion plans and transmission security standards. This depends on a large number of assumptions about the scenario of network expansion. The projected investment costs and associated projected demand increments form the basis of geographically differentiated estimates of the LRMC price of transmission. The NGC in UK rejected the scenario-based approach because of concerns about price stability and acceptability of charges. Another aspect is that this approach implies defining and agreeing these scenarios.

The second is the Investment Cost Related Pricing (ICRP) approach, which, models future investment costs as a function of the configuration and use of the existing network while a scenario-based approach is based upon the specific costs of expected future investments. This approach to use of system charges is not explicitly based upon projections of specific transmission expansion plans. Instead, the cost of increasing capacity on the existing network is calculated under some simplifying assumptions i.e. assumes smooth LRMC incremental investment (and de-investment) in the transmission network for each incremental (and decremental) change in the generation and demand background. The NGC selected this approach to evaluate the use of transmission charges [31].

The concept of LRMC overcomes some of the disadvantages associated with its short-term counterpart. This pricing is less volatile and the calculation methodology is relatively simple. It gives correct price signals to generators and loads for efficient location. They correctly signals to users the long run incremental cost of transmission services over several transmission expansion cycles during which congestion charges could fluctuate up and down many times. As a result, wheeling prices based on long run costs encourage users to compare correctly the total costs of various long-term energy supply alternatives and hence to make good investment decisions and long-term contractual commitments.

Prices equal to long-run costs have also the disadvantages, however, they are may be too high during light load periods and hence economically efficient power transactions during these periods will not be promoted. On the other hand, these prices may not be high enough to limit transmission service usage during peak load periods. Consequently, this method can distort good decision-making about the near-term use of network generation and transmission facilities for minimising energy costs.

2.5.2 Incremental Cost

Incremental cost can be defined as the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission service customer. These facilities must be identified for all years across the life of the contract for transmission service. This includes revenue requirements in years beyond the life of the contract. The transmission service customer pays the full cost for any new facilities that the transaction requires; if a new facility would have been built for other reasons at a later time, then the transmission service customer pays the cost to advance the facility's in-service date. If a facility is needed by more than one transmission service customer, then the cost of the facility can be allocated to the incremental customers by the usage method [2].

Incremental costs can be short-run incremental costs (SRIC) or long-run incremental costs(LRIC). SRIC are the incremental costs of variable costs, including transmission losses, congestion costs and ancillary services costs. LRIC includes incremental cost of both variable cost and fixed costs [6]. The major difference between the marginal and incremental costs is in the way they are evaluated. Incremental costs of a transaction are evaluated by comparing the transmission system costs with and without the entire transaction. However, the marginal approach would multiply the cost for a unit of additional transaction (usually evaluated through a linearised model of system operation by the size of that transaction. there may be large gap between the incremental and marginal costs of a transaction[10].

2.5.2.1 Short-Run Incremental Cost

The Short-Run Incremental Cost (SRIC) entails evaluating and assigning the operating costs associated with a new transmission transaction to that transaction. The transmission transaction operating costs can be estimated using an *OPF* model that accounts for all operating constraints including transmission system (static or dynamic security) constraints and generation scheduling constraints. It should be noted that short-run incremental cost of a transmission transaction could be negative.

There are several concerns associated with the SRIC. First, in order to provide timely economic signals to transmission customers, this pricing methodology should forecast operating costs. This would require forecasting future operating scenarios, which can become less and less accurate as the forecast time horizon extends farther into the future. The second concern is related to the allocation of the SRIC among several transactions that are collectively responsible for changes in operating costs. The third concern deals with volatility of transmission prices determined using this methodology for long-term transactions. These factors would make it difficult to make efficient economic decision for long-term transmission transaction based on short-run incremental cost prices.

Since revenues collected through SRIC only compensate for the operating cost incurred by a transaction, this pricing could discourage host utilities from expanding their transmission system[10].

2.5.2.2 Long-Run Incremental Cost

The Long-Run Incremental Cost (LRIC) entails evaluating all long-run costs (operating and reinforcement costs) necessary to accommodate a transmission transaction and assigning such costs to that transaction. The operating cost component may be evaluated based on same principles as SRIC. The reinforcement cost component of a transmission transaction can be evaluated based on the changes caused in long-term transmission plans due to the transmission transaction. Similar to operating costs, reinforcement costs could be negative indicating that the transaction have resulted in the deferral of planned transmission reinforcements.

Although the concept of reinforcement cost is straightforward its evaluation is very difficult as it involves solving the least cost transmission expansion problem. Here again, there are concerns related to allocation of the reinforcement costs among multiple transactions that collectively cause such costs[10].

2.5.3 Embedded Cost

Embedded cost (EC) is defined as the revenue requirements needed to pay for all existing facilities plus any new facilities added to the power system during the life of the contract for transmission service. The allocation of the embedded cost is done through the usage calculation [2].

The EC allocates the embedded capital costs and the average annual operation (not production) and maintenance costs of existing facilities to a particular wheeling. These facilities include transmission, sub transmission, and substation facilities. The allocation of these costs among the system users is in proportion to their extent of use of the transmission resources. Two traditional embedded cost methods are the Rolled-In-Embedded method, also referred as the Postage Stamp method, and the Contract Path or Red Line method. Neither method requires power flow executions. The Distance Based MW-mile and Power flow based MW-mile methods require execution of power flows. The detail description of these four methodologies will be given in Chapter 3.

The embedded cost methods, which commonly used throughout the utility industry is generally perceived as a fair, if not necessarily an economically attractive, means of compensating transmission owners. It is administratively easy to calculate and fits easily into current rate case procedures. Moreover, the embedded cost methods provide in general, an equitable method of remunerating transmission owners. The primary argument in favour of embedded cost pricing methods is that transmission is a natural monopoly. Transmission owners have a vested interest in scarcity to enable them to extract monopoly profits. These methods can prevent the transmission owners from obtaining monopolistic profits.

However the EC also has some drawbacks such as [32];

- the users are only informed the costs of existing transmission facilities and not the long run costs of transmission expansion

- Does not provide economic incentives for efficient operation of the transmission system. A new transmission transaction is 'transmission-inefficient' if it requires significant transmission reinforcements. However, embedded cost pricing may fail to signal this inefficiency to the offending transaction since the cost of the new reinforcements is distributed among all transmission users.
- Embedded cost pricing is too high during periods of excess transmission capacity and hence economically efficient power transactions during these periods will not be promoted. On the other hand embedded cost pricing is too low to finance expansion when the network has little or no excess transmission capacity.
- it does not reflect the degree to which these facilities are over-utilised or under-utilised and does not provide efficient means to allocate resources to relieve constrained transmission capacity.

2.6 Allocation Methods for Power Flow Contribution to Transmission Services

The cost allocation process involves allocating the individual transmission costs to the transmission users. This process is important to identify the contributions of individual generators and loads to line flows and the real power transfers between individual generators and loads. There are different allocation methods have been formulated in recent years based on the "natural economic use" of the transmission system [17,19,20]. They aim is considering the way the transmission system is impacted by generators and consumers by the simple fact of being connected to the network, irrespectively of their commercial contracts with other agents using the same network. In some countries, this framework gives birth to the " area of influence" concept [17]. Different methods have been suggested to identify the impact a generator or a consumer has on the flow of a transmission line within a transmission network, as well as how much of a generation of a given generator corresponds to a given load [21,22].

These methods include Distribution Factors, AC flow Sensitivities Indices, Full AC Power Flow Solutions, Power Flow Decomposition, Tracing Algorithms, Graph Theory and Cooperative Game Theory. With the application of these methods, the transmission cost can be allocated among the users.

2.6.1 Distribution Factors

Distribution factor based on DC power flows can be used as an efficient tool for evaluating transmission capacity use under various open access structures [17]. These distribution factors, i.e., Generation Shift Distribution Factors (GSDF or A factors), Generalized Generation Distribution Factors (GGDF or D factors) and Load Distribution Factors (GLDF or C factors) have been used extensively in the domain of power system security analysis [9] to approximate the relationships between transmission line flows and the generation/load values. The application of distribution factors for assigning transmission payments may offer transmission providers three alternatives to allocate the total fixed transmission costs among different users, i.e. based on transacted-related net power injections, only to generators and only to loads [18].

Factors GSDF or A factors are defined as

$$\Delta P_{i-j} = A_{i-j,g} \Delta G_g \qquad (2.3)$$

where

$$\Delta G_g + \Delta G_R = 0$$

ΔG_g: generation variation at generator g, with the reference (marginal) generator excluded

ΔP_{i-j}: active power load flow variation in line joining buses i and j, due to the generation variation

$A_{i-j,g}$: proportionality constant or GSDF factor for line i and j and associated to generator g

ΔG_R : generation variation at the reference generator R

Factors GGDF or D factors are defined as

$$P_{i-j} = \sum_{g} D_{i-j,g} G_g \qquad (2.4)$$

where

G_g : total generation at generator g

P_{i-j} : total active power load flow variation in line joining buses i and j

$D_{i-j,g}$: GGDF factor for line i and j and associated to generator g

Factors GLDF or C factors are defined as

$$P_{i-j} = \sum_{g} C_{i-j,c} L_c \qquad (2.5)$$

where

L_c : total demand at load c

P_{i-j} : total active power load flow variation in line joining buses i and j

$C_{i-j,c}$: GLDF factor for line i and j and associated to load c

Factors GSDF depend essentially of the network electrical parameters (reactance in particular) and the election of the reference or marginal bus and they are independent of the operational conditions. However, to determine the impacts on the network of the different injections, it is necessary to know the direction of the power flow in each branch in the study condition. On the other hand, factors GGDF and GLDF depend of the parameters but not of the reference bus location. They are dependent of the studied operational conditions. In summary, to apply them in transmission pricing they present the characteristics indicated in Table 2.1 [19].

Table 2.1 Characteristics of the Distribution Factors for Transmission Pricing

Factors	GSDF or A	GGDF or D	GLDF or C
Applicable to determine by	Generation or load	Generation	Load
Allow allocation of payments based on	Incremental flow	Total Flow	Total flow
Dependence	Election of reference or marginal bus and power flow directions	Operational conditions	Operational conditions

2.6.2 AC Flow Sensitivity Indices

Similar to the application of DC power flow distribution factors, the sensitivity of transmission line flows to the bus injections can also be derived from AC power flow models. One such example can be found in [23] where the contributions of each generation bus to all transmission line MW flows were directly estimated via a set of coefficients named Line Utilisation Factors(LUFs) are shown below.

$$\Delta P_{i,j} = u_1^{ij}\Delta P_{G,1} + u_2^{ij}\Delta P_{G,2} + \ldots\ldots + u_{n-1}^{ij}\Delta P_{G,n-1} + u_n^{ij}\Delta P_{G,n} \quad (2.6)$$

The numerical values of LUFs can be calculated using standard AC power flow Jacobian with some minor simplifications. The concept of Reactive Power Adjustment Factor (RPAF) was introduced in [24] as a measure of the impact of unit MVA load change or a transaction on the total generation reactive power output. The formulation of RPAF is shown below involving only the sensitivity indices of network reactive power losses to the active and reactive injections together with appropriate scaling factors.

$$RPAF = \Delta q_i + \alpha \frac{\partial Q_{loss}}{\partial q_i} \varepsilon_i \Delta q_i + \beta \frac{\partial Q_{loss}}{\partial p_i} \sigma_i \Delta p_i \qquad (2.7)$$

where Q_{loss} is the transmission network reactive losses, Δp_i and Δq_i are the unit active and reactive load at bus i. Scaling factors α and β are used to reconcile the difference between the total system reactive power losses while scaling factors ε_i and σ_i are used to ensure that the load increments Δp_i and Δq_i are consistent with specified power factor at the given bus.

2.6.3 Full AC Power Flow Solutions

More precise cost information is often needed in the assessment of wheeling transactions and that can be obtained by full AC power flow solutions or OPF studies. In a single-transaction case, the "differencing approach" can be used which only involves two AC power flow or OPF studies, one without the transaction (base case) and one with the transaction (operating case)[3]. However, the problem becomes a greater challenge in a multi-transaction case because of the non-linear nature of power flow models and also the interactions among different transactions. Recently, a power flow based multi-transaction assessment methodology was introduced in [25], which involves the following three main study steps.

Step 1) Perform two power flow simulations, one for the base case (no transactions) and one for the operating case (including all the transactions) to determine the combined impacts caused by the transactions on the system. These impacts may include MW/MVAR line flows, reactive power output of generators and real power losses replacement from the slack bus.

Step 2) For each transaction t = 1, …., T, investigate two power flow cases: in one case only transaction t is included and in the other case all transactions except for t are included. Comparing the results of these two simulations with the base case gives marginal and incremental impacts of each individual transaction on the system.

Step 3) The problems of "fair resource allocation" are then solved to distribute the MW/MVAR line flows, reactive power output of generators, and real power losses to each transaction. The formulation below shows an example on how the reactive power support from generator *i*, i.e., ΔQ_i, can be distributed to each transaction by minimising the sum of squared difference between the actual allocation and the marginal and incremental values.

$$\text{Min} \quad \begin{array}{l} J_i = \sum_{t=1}^{T} \left[\left(\Delta Q_{i,t} - \Delta Q_{i,t}^{1} \right)^2 + \left(\Delta Q_{i,t}^{T} - \Delta Q_{i,t} \right)^2 \right] \\ s.t. \sum_{t} \Delta Q_{i,t} = \Delta Q_i \end{array} \tag{2.8}$$

where $\Delta Q_{i,t}, \Delta Q_{i,t}^{1}, \Delta Q_{i,t}^{T}$ are the actual allocated marginal and incremental reactive power support for transaction t respectively. This method is suitable for an open market model consisting of one or more pools, and the study objective is to determine the impact of a transaction on the base operating condition.

2.6.4 Power Flow Decomposition

Power Flow Decomposition (PFD) algorithm is a network solution for allocating transmission services among individual economical transactions on the system [26]. It can determine, for each transaction, the following: i) the usage of transmission network (both real and reactive flow components), ii) the net power imbalance and iii) the contributions from participating generators to real power loss compensation. The algorithm is initially designed for the application in a bilateral contract based market model but can also be used for wheeling transaction assessment [26]. The PFD algorithm is based on superposition of all transactions on the system and decomposes the network flows into components associated with individual transactions plus one interaction component to account for the non-linear of power flow models. Assuming there are totally N transactions on the system, the AC power flow solutions can then be decomposed into:

$$S_N = \sum_{t \in T} S_t + S_{Int} \tag{2.9}$$

$$SM_N = \sum_{t \in T} SM_t + SM_{Int} \tag{2.10}$$

where

S_N is the vector of total complex power injected into the system

S_t is the vector of complex power injected into the system in response to the transaction t, and

S_{Int} is the vector of complex power caused by the interaction among N transactions.

Similar definitions hold for the complex valued flow matrices SM_N, SM_t and SM_{Int}. It has been shown that the calculation of the major contribution of each transaction to the network flows is independent of the interaction effects among different transactions. Theoretically, only a small percentage, in the order of 5% of a given transaction, is in the interaction component under normal operating conditions. Thus, interaction components can be assigned to individual transactions in proportion to the scales of transacted power. This study suggests a revised PFD formulation with distributed slack bus that involves an iteration process to allocate the net current imbalance caused by each transaction among distributed slack bus to determine the network flows. Test results have shown that the revised PFD procedure can be satisfy both the equality criterion and the economic dispatch rule while preserving the same basic assumptions.

2.6.5 Tracing Algorithms

Two tracing algorithms, i.e., the Bialek and the Kirschen, are available. Both are designed for the recovery of fixed transmission cost in a pool based market. The basic assumption used by tracing algorithms is the proportional sharing principle. In

Bialek tracing algorithm, it is assumed that the nodal inflows are shared proportionally among the nodal outflows. Kirschen tracing algorithm assumes that, for a given common (a set of contiguous buses supplied by the same set of generators), the proportion of the inflow traced to a particular generator is equal to the proportion of the outflow traced to the same generator.

1) Bialek Tracing Algorithm: Bialek tracing algorithm has two versions: upstream-looking algorithm and down stream-looking algorithm [21,27,28]. The upstream-looking algorithm will allocate the transmission usage/supplement charge to individual generators and apportion the losses to the loads, and conversely, the downstream-looking algorithm will allocate the transmission usage/supplement charge to individual loads and apportion the losses to the generators.

The algorithm is constructed on a matrix formulation and therefore enables the use of linear algebra tools to investigate numerical properties of the algorithm. Extensive studies have shown its capability and efficiency in allocating transmission usage/supplement charge among different generators or loads under normal operating conditions. The algorithm can also provide solutions to the questions as how much of the power output from a particular generator/station goes to a particular load or how much of the demand of a particular load comes from a particular generator/station.

The proposed algorithm initially works only on lossless flows whereby the flows at the beginning and end of each line are the same [27]. However, the author has extended its uses to allocate the transmission loss to loads or generators [21]. If the problem is analysed from the perspective of generation, the power injections in each bus of the system are given by [30]:

$$P_i = \sum_{j \in \alpha_i^{(u)}} \left| P_{i-j} \right| + P_{Gi} \qquad \forall i = 1,2,\ldots\ldots,n \qquad (2.11)$$

where P_i is the total flow through bus i, $\alpha_i^{(u)}$ is the set of buses that directly supply bus i(the flow must go from other buses to bus i), P_{Gi} is the generation in bus i and P_{i-j} is the line flow in line j-i where

$$\left|P_{i-j}\right| = \left|P_{j-i}\right|$$

Using the proportionality principle, the flow in a line can be written as

$$\left|P_{i-j}\right| = c_{ij} \cdot P_j \text{, where } c_{ji} = \left|P_{i-j}\right| / P_j$$

Replacing in (2.11) we obtain:

$$P_i = \sum_{j\in\alpha_i^{(u)}} c_{ij} \cdot P_j + P_{Gi} \qquad \forall i = 1,2,\ldots\ldots,n \qquad (2.12)$$

and rearranging it

$$P_i - \sum_{j\in\alpha_i^{(u)}} c_{ij} \cdot P_j = P_{Gi} \quad o \quad A_u P = P_G \qquad (2.13)$$

where A_u is an (nxn) distribution matrix per injected powers, P is the vector of bus flows and P_G is the vector of bus generations.

The elements of matrix A_u are defined as follows:

$$[A_u]_{ij} = \begin{cases} 1 & \text{for } i = j \\ -c = \dfrac{-\left|P_{j-i}\right|}{P_j} & \text{for } j \in \alpha_i^{(u)} \\ 0 & \text{otherwise} \end{cases} \qquad (2.14)$$

where j must be a bus that supplies power to i.

If A_u^{-1} exists, then vector $P = A_u^{-1} \bullet P_G$ and its elements are given by

$$P_i = \sum_{k=1}^{n} \left[A_u^{-1}\right]_{ik} \bullet P_{Gk} \quad \text{for } i = 1,2,\ldots,n \tag{2.15}$$

The last equation shows that the contribution from generator k to bus i is equal to $\left[A_u^{-1}\right]_{ik} \bullet P_{Gk}$. A withdrawal of power in line i-l from bus i can be calculated as:

$$\left|P_{i-l}\right| = \frac{\left|P_{i-l}\right|}{P_i} \bullet P_i = \frac{\left|P_{i-l}\right|}{P_i} \sum_{k=1}^{n} \left[A_u^{-1}\right]_{ik} \bullet P_{Gk} \tag{2.16}$$

$$= \sum_{k=1}^{n} D^G{}_{i-l,k} \bullet P_{Gk} \quad \text{for } l \in \alpha_i^{(d)}$$

where $\alpha_i^{(d)}$ is the set of buses directly supplied by bus i and

$$D^G{}_{i-l,k} = \frac{\left|P_{i-l}\right| \cdot \left[A_u^{-1}\right]_{ik}}{P_i}$$

is topological generation distribution factor, indicating the proportion of power that generator k contributes to line i-l

where

P_{i-l} is the power flow in line *i-l*

A_u^{-1} is the distribution matrix

P_i is the total flow through bus *i*

These D factors indicating the proportion of power that generator k contributes to line *i-l*. It is also the ones that permit to allocate the actual use of the transmission lines. In addition, as the topological distribution factors are always positive, thus no counterflows are encountered and all the charges to the network users are positive.

Minor error may be incurred when the lines are heavily loaded due to the assumptions used in the problem formulation.

2) Kirschen Tracing Algorithm: The Kirschen algorithm also has two versions designed for identifying the contributions from either the individual generator or loads to the line flows [22,29]. In general, this algorithm shares many useful functions and attractive features with the Bialek tracing algorithm.
This algorithm is based on a set of definitions [30]:

Generator's domain: Generator's domain is defined as the group of buses that are reached by the power generated by a given generator. The power of a generator is capable of reaching a particular bus only if it is possible to find a way through the grid that links them, where the direction of the trip is consistent with the direction given by a load flow.

Commons: A common is defined as a group of neighbouring buses supplied by the same generators. The number of generators that supply a common is defined as the rank of the common, and can be between one and the total number of generators in the system.

Links: The lines that connect two different commons are defined as a link. The flows in the lines of a particular link are in the same direction, always from a common of rank N to other of rank M, where M>N always.
The method calculates the internal flows of each common as the addition of the power injected by the generators in common buses, plus the imported power from others commons through the links.
The external flows of a common are defined as the power exported through the links to other commons of higher rank. It uses the same proportionality principle as Bialek, but with a difference. While Bialek applies it to each bus of the system, Kirschen applies it to the commons. Doing this, the following proportionality assumption can be made: "For a given common, if the proportion of internal flow which can be traced to generator i is x_i, then the proportion of the load in this common and the external flow of this common which can be traced to generator i is also x_i". With this

assumption, a recursive method is built to determine each generator's contribution to supply the loads in each common. The following variables are defined:

C_{ij} : contribution by generator i to the load and external flow of common j

C_{ik} : contribution by generator i to the load and external flow of common k

F_{jk} : flow from common j to common k through the link

F_{ijk}: flow from common j to common k through the link coming from common i

I_k : internal flow of common k

The following relations are defined:

$$F_{ijk} = C_{ij} \cdot F_{jk} \tag{2.17}$$

$$I_k = \sum_j F_{jk} \tag{2.18}$$

$$C_{ik} = \frac{\sum_j F_{ijk}}{I_k} \tag{2.19}$$

These recursive equations are the ones that will be used to calculate each generator's contribution in each common. The calculation begins with the "root" commons, those with rank 1, where their internal flows are entirely produced by generators inside the common. The next step is to calculate the external flows for these commons and then continue with the others of higher rank. In short, what is obtained is the proportion of the contribution of each generator to each common and therefore, to each line inside this common, as well as the proportion of the flow that leaves each common.

Kirschen tracing algorithm is able to work well under various system-loading conditions because no additional assumptions are used in the problem formulation. On the hand, it is a simplified approach since the contributions from the generator (or loads) to a particular common will be proportionally assigned to the loads (or generators) and line flows within that common[18].

2.6.6 Graph Theory

Graph theory has been suggested in [38] to calculate the contributions of individual generators and loads to line flows and the real power transfer between individual generators and load. In this method, the vertices of the graph are system buses and the edges of the graph are lines and transformers. The directed graph of active power flow may be different from that of reactive power flow in edge directions. The bus-line incident matrix is used to determine the downstream and upstream tracing sequences. The downstream tracing is performed to determine the contribution factors of generations to the line flows and loads. In the other hand, the upstream tracing is performed to determine the extraction factors of individual loads from line flows and generators. This suggested is claimed to be efficient and suitable for use in real power system.

2.6.7 Cooperative Game Theory

Game theory is another method used extensively for transmission cost allocation. This theory is sometimes described as multi-person decision theory or the analysis of conflict [11]. In particular, cooperative game theory arises as one of the convenient tool to solve cost allocation problem. This theory is based on two fundamental principles: (1) global rationality: the total payoff is equal to the sum of individual payoff. (2) coalition rationality: the payoff with any sub-coalition breaking away could be higher than if they stay. The solution mechanisms of cooperative game theory behave well in terms of fairness, efficiency, and stability, qualities required for the correct allocation of transmission costs. Nevertheless, proposals to date are still in a developing stage, with contributions being formulated in allocating wheeling transactions costs [12, 13], in the allocation of expansion costs [11,14], allocation for both existing and expansion networks costs [15] or and resolve coalition formation for multilateral trades [16].

2.7 Pricing Methods for Transmission Services

There are more than 24 different methods of pricing transmission service [37]. This section however describes five pricing methods currently in use or under consideration including point-to–point (distance based), postage stamp, nodal pricing, zonal pricing congestion pricing and counterflow pricing methods.

2.7.1 Point-to point (Distance based)

This method derives the charges, which reflects the quantity of the electricity product and the distance the product is carried from the supplier to the consumer. The common link among all distance related methods is that a transaction is charged based on the extent to which specific transmission facilities are used in support of the transaction. The extent of transmission facility use is established by analysing the transmission system with and without a specific transaction to determine the change in power flow on each transmission facility due to the transaction. The change in power flow, the length or type of facility, and the cost of the impacted facility all affect the transaction charge for the use of the transmission system.

2.7.2 Postage Stamp

In this method, all of the transmission system infrastructure costs are averaged over a base of transmission customers who use the infrastructure. All users pay the same price for transmission service irrespective of their geographic location, and the charge is usually based on their peak usage/ demand. This reflects the basic concepts behind the design of the transmission system to meet peak capacity requirements. This method has been widely used throughout the transmission utilities as the basis for recovery of the embedded costs of the transmission system infrastructure.

2.7.3 Nodal Pricing

The nodal pricing method, which derived from marginal cost theory, is found the most complicated but accurate pricing method. This method can be short-run marginal(incremental) cost based or long run marginal (incremental) cost based, depending on type of costs recovery needed. This method determines prices for power at each bus of the system accounting for all costs and transmission constraints. The nodal prices are typically calculated as variables or Lagrange multipliers of an optimal power flow (OPF) calculation. Marginal transmission prices are derived directly from nodal prices. If MP_i and MP_j are the marginal nodal prices of electricity at buses i and j, the marginal transmission price is MP_i - MP_j and is a measure of what it costs the grid to accept an additional unit of power at i and to deliver it at j. A major advantage of this method that the right operational pricing signal are revealed. The major disadvantage is the need for a separate revenue reconciliation exercise.

2.7.4 Zonal Pricing

This method attempts to reflect more accurately the true cost of providing transmission service to customers located in different parts on the transmission system. This method represents a combination of the postage stamp method and the nodal pricing method and can be short-run marginal(incremental) cost based or long run marginal (incremental) cost based as nodal pricing. Generally, the nodal pricing method is first utilised to obtain the prices in all buses, and then a weighed average value of all nodal prices within a zone is set as the zonal price. This is done periodically to account for the change of system conditions. The nodal prices at all buses in a zone should be reasonably close to each other for the to be meaningful. Otherwise zonal boundaries should be adjusted. The NGC in the UK, for example employs zonal pricing method based on long-run marginal cost which involves 15 generation zones and 12 demand zones. The determination of zonal prices is somewhat subjective and this represents a major disadvantage, but the method is simple and easy to implement.

2.7.5 Congestion Pricing

Congestion occurs when the transmission network is not sufficient to transfer electric power according to the market desire. Several alternatives could be considered to solve the congestion problem, such as re-dispatching existing generators or dispatching generators outside the congested area to supply power. In both alternatives, congestion has costs based on differences in energy prices. There are three basic approach can be used to allocate the congestion costs to the transmission users that reflects the actual use of transmission system [39]:

Costs of out-of-merit dispatch: In this approach, congestion costs are allocated to each load on transmission system based on its load ratio share (i.e. individual load expressed as a percent of total load).
Locational Marginal Prices (LMPs): LMP is calculated based on the cost of supplying energy to the next increment of load at a specific location on the transmission network. It determines the prices that buyers would pay for energy in a competitive market at specific locations and measures congestions costs by considering the difference in LMPs between two locations. In this approach LMPs are calculated at all nodes of the transmission system based on bids provided to the PX.
Usage charges of inter-zonal lines: In this approach, the ISO region is divided into congestion zones based on the historical behaviour of constrained transmission paths. Violations of transmission lines between zones (inter-zonal lines) are severe while in the congestion zone transmission constraints are small. All transmission users who use the inter-zonal pay usage charges. These charges will be determined from bids submitted voluntarily by market participants to decrease or increase (adjust) power generation. Adjust bids reflect a participants willingness to increase or decrease power generation at a specified cost. The California market such as an example employed this approach.

Most congestion pricing pair nodal prices with a separate access charge (usually a postage stamp charge). The nodal prices ensure a competitive market and efficient allocation while the access charge allows the transmission provider to recover the full embedded cost of the transmission system.

2.7.6 Counterflow Pricing

Counter flow or negative flow is the flow component contributed by a particular transaction that goes in the opposite direction of the net flow. According to this method, the transmission user who reduces the total net flow would receive a credit for using the transmission services. The intuitive justification for this credit is that, by reducing the total net flow, this participant may be avoiding or postponing future system reinforcement. However, in view of the contributions of counter flows in relieving the congested transmission lines, any usage- based tariff that charges for counter flows needs to be carefully reviewed. In this regard, the zero counter flow pricing method suggests that only those that use the transmission facility in the same direction of the net flow should be charged in proportion to their contributions to the total positive flow [18].

However, many transmission service providers felt uncomfortable with the idea of providing the service and in addition paying the transmission users their contribution in counter flow.

Based on this situation, the research is taking place to develop a methodology whereby the counterflow pricing not only can be benefited to the transmission users but also the transmission owners. The developed methodology is presented in Chapter 4.

2.8 Revenue Reconciliation of Transmission Services

Revenue requirement of transmission service reflects to the costs associated with all components needed to pay for a transmission facilities such as return of investment (usually depreciation), return on investment, taxes and expenses (operating, maintenance, administrative and other expenses that are related or allocated to the facility). The cost of facility depends on whether the cost basis is embedded, incremental or marginal.

As it has been noted in section 2.5.1, marginal costing based approach to transmission pricing always tends to under recover the revenue required by the transmission service provider, due to high capital investment associated with a transmission network compared to its variable operating costs. This brings in the concept of revenue reconciliation in transmission pricing [33]. Revenue reconciliation is the tariff that is required to realise appropriate revenue to the transmission owner [34].

This tariff is required to ensure that the transmission owner do not make or lose too much money. There are three approaches to revenue reconciliation; (1) modifying the wheeling rates, (2) using of surcharge or refunds and (3) using revolving funds. However, no approach is superior since each has its own advantages and disadvantages [35].

Economists offer different options for allocating this reconciliation among the different users of determined services. The methods based on Ramsey pricing scheme, uniform uplift, independent measure, use of system and benefit of existence of transmission services are among the options that are proposed for revenue reconciliation. However, the use of system allocation is being utilised by many regulating schemes worldwide. Although they are not orthodox economic signals, engineers tend to link use with payment [17]. Meanwhile, in this thesis, a new approach is developed to allocate this reconciliation using profit sharing concept.

The developed approach modifies the existing MW-mile method in such a manner that the transmission owners and the users will share the benefit due to the negative flow created in the network [36]. It can be seen in the case study results which will be presented in Chapter 5, this approach provides intuitive way for all participants to remain in the trading and ensures revenue reconciliation for the transmission owners.

2.9 Summary

This chapter discussed in some details the cost and the pricing of transmission services in the deregulated environment. The first section of the chapter defined two types of transmission services, explaining the structure of each services in term of the transaction and the cost related services. The discussion continues with the cost elements arising from the transmission services, which can be classified as fixed costs and variable costs. These cost elements include the costs of construction, maintenance and operation of transmission network; costs of losses; congestions costs and costs of ancillary services which can be used by the transmission utility to charge the users due to the service offered. In this thesis, however, limited research work is done on the costs of construction, maintenance and operation of transmission network. The chapter then defines and analyses the cost methodologies used to recover the costs of transmission services. These costs methodologies, which include marginal, incremental and embedded cost methods, have their own advantages and limitations in its application to the power system transmission. For example, SRMC has been popular due to its economic basis, however the charges obtained will not be sufficient to recover the revenue required by the transmission utility. While the EC methods provide in general, an equitable method of remunerating transmission utilities and is commonly used throughout the utility industry. The primary argument in favour of these methods is that; transmission is a natural monopoly. However, the EC also has some drawbacks, i.e. the users are only informed the costs of existing transmission facilities and not the long run costs of transmission expansion and it does not provide economic incentives for efficient operation of the transmission system. This chapter also discusses several allocation methods that can be used in identifying the contributions from either the individual generators or loads to the line flows. For instance, the allocation method such as the distribution factors based on DC power flow has offered transmission owners three alternative approaches to allocate the transmission costs among different users, i.e. based on transacted-related net power injections, only to generators and only to loads. On the other hand, the AC power flow solution and the Power Flow Decomposition, have the capability to determine the usage of transmission network in both real and reactive flow components. Both DC and AC power flow based may help the transmission owners to allocate the cost of transmission system among all the system users in a non-discriminatory way, and at the same time provides them the correct economical signal. However, the distribution factors based on DC power flow are commonly used by many transmission utilities (e.g. CAISO, PJM, NE-ISO etc.) although the power flows found from this allocation method represents an approximation of real system flows.

This chapter has also discussed some of the transmission service pricing methodologies that is currently used or under consideration by transmission utilities. These methods include from the simple one such as postage stamp to the more complicated one such as congestion pricing. It can be observed that almost all the pricing methods cannot solely rely on its own scheme alone in providing sufficient revenue for transmission service. In most cases, they need to combine with each other (i.e. zonal pricing and congestion pricing). Postage stamp method on the other hand has been widely used throughout the transmission utilities as a basis for the recovery of the fixed costs of the transmission network. However, this method has been critised due to the lack of undertaking of the actual system operation.

Meanwhile, the counterflow pricing method is still being debated. According to this method, the transmission user who reduces the total net flow would receive a credit for using the transmission services. Although some alternative methods had been developed such as the zero counter pricing, which based on MW-mile methodology, but this idea may not easily be accepted by the transmission utilities. Finally, this chapter explores the issue of revenue reconciliation for transmission services, together with the concept and the option methods that can be used by the transmission services utility to remunerate the total transmission system cost.

In conclusion, the chapter provides a useful framework to analyse the transmission services issues. This framework which can be divided into three important steps; define transmission services, identify transmission costs and calculate transmission costs can be used by the transmission owner to generate an appropriate amount of revenue of the related services. As has been highlighted in this chapter some aspects related to the transmission services can be improved especially in the issues of allocation method, pricing the counter flow user and revenue reconciliation; therefore, a research is required to tackle these issues which is the main aim of this thesis.

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CHAPTER 3

THE USE OF SYSTEM CHARGES: WHEELING CHARGES

3.1 Introduction

The electrical industry restructuring has changed the electricity business from vertically integrated industry to a segmented industry based on competition among participants. The new scheme established free access to the transmission lines and compulsory connection to the grid, that have allowed generators to transport their energy to the main consumer centres, boosting a competitive environment among generators and consumers. In that environment, the transmission network is considered to be the key factor of the electricity markets.

One of the important issues in this context is how to charge the users for the use of transmission facilities in the fair way and at the same time allowing the transmission utilities to recover their transmission costs. Several methodologies have been developed so far to recover the cost transmission services. There are also methods that have been developed to estimate the power contributed by single generating unit in lines and loads. Both developed methods attempt to allocate the charge of the use of the transmission system as has been explained in Chapter 2. In this chapter the issues of use of system charges will be discussed, as it is related to the pricing of the transmission services. The discussion focuses on UK's use of system charges methodologies, which covers the conceptual, the components associated with the charges and the charge allocation. This chapter also discusses the phenomena of wheeling and the cost associated with wheeling to highlight the significant of the wheeling charges as the components of use of system charges. The current wheeling charge methodology used by transmission utilities in United Kingdom and some other countries are presented at the end of this chapter.

3.2 Use of System Charges

The use of system charges is the main elements of all existing electricity transmission tariffs and they represent the crucial point in the discussion transmission open access arrangements. This charge reflects the cost of building, maintaining and running the transmission system relating to the transmission utility activity of the transmission business. The transmission utility charges distributors and generators and any transmission customers for use of the shared transmission network. The key principles of the use of system charges are as follows [1]:

- the charges should recover the correct amount of revenue and should be consistent.
- the charges should provide efficient economic signals to users to reflect the incremental costs of providing transmission capacity.
- the charges should not discriminate between any partner or any classes of users.
- the charges should, as far as possible, be simple, predictable and transparent to users.

The concept of these charges varies from one transmission utility to the other, however this chapter discusses the use of system charges in the UK's transmission utilities context.

3.2.1 Components in Use of System Charges

The basis for determining use of system charges is a transaction-independent point model. All system users contribute to the system costs through an annual use of system charges. The components include in the use of system charges are justified by the transmission utility, however in general the charges for use of transmission system comprise the following elements [2]:

(a) a *system service charge* covering the assets required to provide a connection between all points of the main system and so provide and maintain a basic network having stable voltage and frequency onto which generators and loads can connect

(b) an *infrastructure charge* covering the balance of assets of the main interconnected system which are necessary to provide firm transfer capacity and system security

(c) an *exit charge* covering the assets required to provide a connection between the transmission system and the distribution system, and between the transmission system and any transmission connected customers

(d) an *entry charge* contributing towards the assets required for reinforcements of and connections to the main interconnected transmission system as a result of new generation connections.

(e) a *wheeling charge* is the charge for the use of transmission network. This charge incurred when the vertically integrated utility offers wheeling service to specific entities, e.g. non-utility generators and large users. The detail of this charge is discussed in section 3.3.5

3.2.2 Allocating Percentage of Use of System Charges

The transmission utilities differ in justification of their methods to allocate the use of system charges to the users. In this context, the users can be defined as generators, demands and wheelers. Thus, it has to be decided who has to pay the charges. Three characteristics are possible: (1) all charges are assigned to the generator (2) all charges are assigned to the demand (3) the charges are shared between the generator and the demand. However, in order to create a fairness environment in transmission pricing, the allocation schemes should have the following properties such as; it provides complete cost recovery of the transmission services and the allocation should be based on the actual usage of the service, i.e. generators or demands should be charged for transmission services based on their actual use of each transmission network. Within these concepts, the Latin America countries and some other countries in the European region have chosen different approaches to allocate the charges for the use of transmission system services to the users. For example, in both Chile and Argentina, who are amongst first set of countries to deregulate, chose to allocate the charges only to the generators. This was justified with the belief that transmission services are required by the generators to reach consumers and compete [3]. On the other hand, England and Wales allocates the charges between generators and demands approximately in the ratio of 27/73 to maintain the balance of overall transmission revenue. Other countries extend these charges to consumers and wheelers. The wheelers being the utilities whose network are used for wheeling.

Table 3.1 shows the use of system charges allocation schemes used by some countries around the world [4].

Table 3.1 Use of System Charges Allocation Schemes.

	England & Wales	Argentina	Colombia	Chile	Norway	Brazil	Ireland
Generators	27%	100%	50%	100%	36%	50%	25%
Demands	73%	0%	50%	0%	64%	50%	75%
Wheelers	0%	0%	0%	0%	0%	0%	0%

3.2.3 UK's Use of System Charges Structure

This section discusses the use of system charges that are presently levied for the transmission systems in the UK, which involved three main transmission utilities. The transmission utilities are National Grid Company (NGC), Scottish Hydro Electric Transmission Limited (SHETL) and Scottish Power Transmission Limited (SPTL) transmission companies.

3.2.3.1 NGC's Use of System Charges

National Grid Company (NGC) levies two separate types of charges for use of system. It levies Transmission Network Use of System (TNUoS), which cover the long term costs of providing and maintaining transmission assets, and Balancing Services Use of System (BSUoS) charges, which cover the short-term costs of maintaining a balanced system in real time.

NGC's TNUoS charges are levied on generators and demand. Charges vary by location and depend on whether a party is a net exporter (i.e. putting energy on to the system) or a net importer (i.e. taking energy off the system) at times of peak demand. Ordinarily generators are net exporters, and suppliers and large industrial customers are net importers. Where exporting and importing parties join together to form trading units (the rules for which are set out under the Balancing and Settlement Code (BSC)) the charge depends on the total net exporter or import of the trading unit.

NGC's TNUoS charges are levied on a zonal basis and can be considered to have two elements. Firstly, a charge to reflect the long-run marginal cost of a change in generation or demand at a particular point on the network and it varies by location. Secondly, a charge to reflect the overall cost of providing a secure network. This second element is used to ensure that NGC is able to recover its total allowed revenue. TNUoS charges are calculated by taking the marginal costs and uplifting them by a flat rate (the residual charge) for all zones. The locational element of charges is currently derived by NGC using Investment Cost Related Pricing (ICRP) transport model. This ICRP model uses a simplified model of the transmission system to approximate the Long Run Marginal Cost (LRMC) of investment in the transmission system. The transport model uses a stylised representation of available transmission routes to estimate the difference in marginal cost (in terms of additional km of transmission line) of an additional of 1MW of generation or demand at each node on the network. Nodal results can be positive or negative, depending on whether an additional MW increases or decreases the overall utilisation of the routes within the transport model. The nodal results from the transport model are then grouped to form charging zones, with the charge for a particular zone being the weighted average of all relevant nodes within that zone. There are currently fifteen generation zones and twelve demand zones as shown in Appendices A1 and A2. The final tariffs are derived from the results of the transport model by uplifting by a flat rate in each zone to ensure that 73% of total use of system revenue is recovered from demand and 27% is recovered from generation, and that total revenue is consistent with NGC's Transmission Owner (TO) price control. TNUoS charges recover around £600 millions a year (2003). The location tariffs derived from the transport model (before being uplifted) account for approximately 25% of this total [5]. The use of system charges tariffs for NGC's system in 2003/04 are shown in Table 3.2 [6].

Table 3.2 NGC's Use of System Tariffs for 2003/04

Generation Zone	Zone Area	Generation Tariff (£/kW)	Demand Zone	Zone Area	Demand Tariff (£/kW)
1	North	9.070559	1	Northern	0.581892
2	Humberside	5.371999	2	North West	5.036761
3	North Yorks and North Lancs	5.043993	3	Yorkshire	4.466802
4	South Yorks and South Lancs	3.848250	4	North Wales and Mersey	5.134530
5	North Wales	5.559611	5	East Midlands	7.352609
6	West Midlands	1.421129	6	Midlands	9.110320
7	Rest of Midlands and Anglia	1.881197	7	Eastern	8.470207
8	South Wales	-4.304565	8	South Wales	13.595716
9	Wiltshire	-2.452289	9	South East	10.232167
10	Greater London	-0.202412	10	London	13.502983
11	Estuary	0.625400	11	Southern	12.680990
12	Inner London	-10.544910	12	South Western	15.844045
13	South Coast	-3.628069			
14	Wessex	-5.789249			
15	Peninsula	-10.142785			

However, NGC's charging review initial conclusions indicate that it might be appropriate to replace this model with a DC load flow transport model. The reason is that the current transport model only uses a single direct route between any two connected nodes and does not consider the electrical characteristics of the network in determining flows e.g. the impedance of each given route. Additionally, it also only uses the shortest route at the exclusion of any alternative longer route and does not take into account any line limits. The methodology of proposed model is discussed in Section 3.5.1.

Meanwhile, balancing costs are recovered via BSUoS charges, which cover the costs of bids and offers accepted in the balancing mechanism provided for in the BSC, the costs of all balancing services, a number of minor adjustment parameters, a level of associated internal costs, and any associated incentive payments under NGC's system operator incentives scheme. Conceptually, BSUoS costs can be considered to include two types of balancing services. Energy balancing relates to actions taken to adjust for any overall imbalance between generation and demand on the transmission system. System balancing relates to actions taken over and above those required by energy balancing to maintain the quality and security of supply.

3.2.3.2 SPTL's Use of System Charges

Scottish Power Transmission Limited (SPTL) use of system charges comprise system service charges, levied on demand, and infrastructure charges levied on both generation and demand. System service charges reflect the costs of providing a core network having stable voltage and frequency. Infrastructure charges reflect the costs of providing firm transfer capacity between transmission entry and exit points. Infrastructure generation charges depend on generation capacity, and infrastructure demand and system service charges are dependent on demand at times of system peak. System peak is characterised as the three half-hour periods of peak demand separated by at least ten days in the period between November and February. Neither infrastructure charges nor the system service charge vary by location within SPTL Transmission's area.

SPTL Transmission's use of system charges is calculated annually, and in total account for around £47m per year (2003). The SPTL's use of system charges rates for 2003/04 are depicted in Table 3.3 [5].

Table 3.3 SPTL's Use of System Tariffs for 2003/04

Infrastructure	
- generation	£ 2.45 per kW of chargeable generation capacity
- demand	£2.01 per kVA chargeable demand
System service	£3.70 per kVA of chargeable demand

3.2.3.3 SHETL's Use of System Charges

Scottish Hydro Electric Transmission Limited (SHETL) use of system charging structure is broadly similar to that of SPTL. It levies infrastructure charges on generation and demand, and a system service charge on demand. The key difference is that SHETL levies an Entry Charge (as defined in SHETL's transmission use of system charging statement) on generation connected to their system after 1 April 2002.

The Entry Charge shares reinforcement costs caused by new generation amongst all new generator connection. In common with SPTL, charges are calculated on the basis of generation capacity and demand at system peak [5]. The SHETL's use of system tariff for 2003/04 are shown in Table 3.4 [3].

Table 3.4 SHETL's Use of System Tariffs for 2003/04

Infrastructure	
- generation	£ 5.4420 per kW of authorised generation capacity
- demand	£5.8772 per kW chargeable demand
System service	£3.7974 per kW of chargeable demand
Entry (generation)	£5.5164 per kW of authorised generation capacity.
Exit(demand)	£6.5912 kW of chargeable demand

3.3 Wheeling and Wheeling Charges

Wheeling is among the most important electrical supply options available to transmitting utilities. In the past, wheeling has not been an important issue since the utilities were asked to provide very limited wheeling. However, with deregulation, it receives a lot of attention because of the expansion in the number and type of wheeling transactions, which involves several parties. Power from seller to buyer flows through several intermediate utilities. Each utility represents an individual control area, engaged in part of a more complex wheeling transaction. The issues that need to be addressed in this context are, how much power should be wheeled through each path, what wheeling charges should be applied to each transaction and how these decisions can be made optimally.

The following sections will discuss the wheeling concept in general including its types and durations. It also discusses the costs associated with wheeling transaction and the establishment of wheeling charges rate.

3.3.1 The Concept of Wheeling

There are many definitions for wheeling depending on each author's preferences. It may be defined as " the use of transmission or distribution facilities of a system to transmit power of and for another entity or entities. It may also be defined as " the use of some party's (or parties) transmission system(s) for the benefit of the other parties." The simple definition is "Wheeling is the transmission of power from a seller to a buyer through the network owned by a third party" [7]. Wheeling transaction defines the transmission of electric power for other entity(ies) by a utility that neither generates nor intends to use the power as a system resource for meeting its own native load. The receipt and delivery of the wheeled power must be simultaneous [8].

At least three parties are involved in a wheeling transaction: a seller, a buyer and one or more wheeling utilities that transmit the power from the seller to the buyer. The third party is paid for the use of its network. Figure 3.1 shows a simple wheeling topology. For instance, Utility A wishes to sell power to utility C. Utility A and Utility C do not have direct interconnection, and utility B however as the wheeler is an intermediate utility between A and C. Therefore, the power sold from utility A to utility C must pass through utility B. It is said that power is wheeled through B. Such transactions are coordinated among the supplying side, the receiving end, and one or more intervening wheeling systems.

Power wheeling is accomplished by increasing generation in the supplying utility A, and reducing an equal amount of generation in the receiving system, utility C. The result will change the power flow pattern of whole system, including those of the intermediate, utility B. Utilities A or C, or both A and C should pay a wheeling charge for transmission access to compensate for the use of utility B's transmission system.

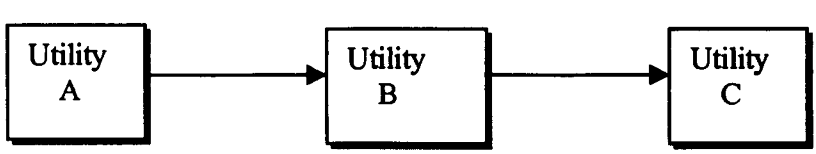

Figure 3.1 Simple Wheeling Topology

3.3.2 Types of Wheeling

There are different type of wheeling, depending on the relationship between the wheeling utility and other two parties. There are four broad categories of the relationships in wheeling [9].

(1) Utility to utility: from one regulated utility to another regulated utility for bulk power wheeling via transmission network of an intervening utility.
(2) Utility to private user or requirements customers: a private user or requirement customer such as an industrial customer purchases energy from a regulated utility that does not service the customer's geographical location. To consummate such a purchase, transmission service by the intervening utility would be required.
(3) Private generator to utility: a private generator sells to a utility whose service territory does not cover the geographic location of the generator.
(4) Private generator to private user: a private generator sells to a private user both of whom are located in the wheeling utility's service territory.

Wheeling can occur between individual buses or areas. Type 1 illustrates area-to-area wheeling, that is, the selling and buying utilities cover geographical areas which are interconnected wheeling utility. Type 2 illustrates area to area wheeling, unless the requirements customer is so small that it is fed only at one bus and this becomes area wheeling. Type 3 illustrates bus to area wheeling and type 4 illustrates bus to bus wheeling, that is, the seller and the buyer is located at a different bus.

3.3.3 Nature and Duration of Wheeling

Wheeling may be firm, or uninterruptible. The 'native' firm load is the highest level of firmness. This means that the wheeling transaction has the same priority as the 'native' load of the utility providing the wheeling. Interruptible wheeling allows the utility providing the services to cease sending for specific reasons e.g. unavailability of surplus or transmission capacity. There are several categories used to identify the type of a wheeling service, which will be discussed below [10,11].

3.3.3.1 Firm Wheeling Transactions

These transactions are not subject to interruptions. Firm power wheeling is so called reserved transactions since they make reservation of capacity on transmission facilities to meet transaction needs. A firm transmission transaction is the result of contractual agreements between the utility and the wheeling customers.

3.3.3.2 Non-firm Wheeling Transactions

These transactions may be curtailed or on an as- available basis. Any on going non-firm transactions may be curtailed at the utility's discretion. As-available transactions are short term, mainly economy transactions that take place when transmission capacity becomes available in specific areas of the system at specific times.

3.3.3.3 Long-term Wheeling Transactions

A long-term transaction takes place over a period spanning several years. The duration of a long term transmission is usually long enough to allow building new transmission facilities. Transmission service provided as part of long-term firm power sales is an example of long-term transmission transaction. Long-term wheeling transactions are the result of contractual agreements between the utility and the wheeling customers.

3.3.3.4 Short-term Wheeling Transactions

A short-term transmission transaction may be as short as a few hours to as long as a year or two, and as such is not generally associated with transmission reinforcements. Short-term transactions may be provided under a bilateral contract or as part of a pooling arrangement.

3.3.4 Costs Associated with Wheeling

Wheeling costs are incurred by all companies that experience a change in power flows over their transmission lines during a specific transaction, whether or not the lines of that utility are part of the contract path. The costs of providing wheeling service differ from one system to another and from one kind of wheeling transaction to another. While most transactions may be completed using existing capacity, others may require an increase in line. Depending on the situation, some cost components may be high, low, negative, or not incurred at all. In this section, the detailed discussion of the components of the costs associated with wheeling transaction is discussed [11].

3.3.4.1 Operating Cost

The operating cost of a wheeling transaction is the production cost that the utility incurs in order to accommodate the transaction. The operating cost is due to generation rescheduling and re-dispatch. Generation re-dispatch is caused by change in losses and by operating constraints such as transmission flow and bus voltage limits. Generation rescheduling is impacted by factors such as the start-up time and start-up cost of generating unit and the spinning reserve requirements. The operating cost of a wheeling transaction will be negative if the transaction reduces the production cost. Production cost is reduced via improving generation dispatch due to lower losses and/or mitigation of operating constraints and via improving generation scheduling.

3.3.4.2 Opportunity Cost

The opportunity cost of a wheeling transaction corresponds to the benefits unrealised due to operating constraints that are caused by the transaction (cost of lost opportunities). The benefits unrealised due to lost opportunities may rise through one or both of the following mechanisms:

- unrealised savings in production cost if the utility could not bring in cheaper energy due to operating constraints. A wheeling transaction causing such constraints results in lost benefits and hence incurs some cost. The opposite is also true. If a transaction mitigates transmission congestions allowing additional transactions to take place, it provides some benefits and reduces cost.

- Unrealised contribution to the cost of existing transmission system by all potential firm transactions that are forgone due to operating constraints. Since part of the cost of existing facilities are allocated to firm transactions, their loss results in lost benefits. Hence, a transaction causing the transmission constraints incurs cost for transactions already on the system. The opportunity cost is the most elusive component of the cost of a wheeling transaction. There are questions and concerns on the justification and the evaluation of this cost. The main argument related to the opportunity cost of a transaction stems from the need to make assumptions about potential transactions that are foregone due to the transactions under consideration. There is also very little experience in evaluating opportunity costs for wheeling transactions.

Opportunity cost may be incurred by a utility that offers firm wheeling but might not be incurred with interruptible wheeling, depending on the conditions of interruption in the wheeling contract. Further this cost is strongly related to the level and efficiency of use of transmission facilities.

3.3.4.3 Reinforcement Cost

The reinforcement cost of a wheeling transaction corresponds to the cost of all transaction reinforcement necessary to accommodate that transaction. Reinforcement cost can also be the cost of planned transmission reinforcements that are deferred by the transmission transaction. In its latter form, the reinforcement cost of a wheeling transaction will be negative. Although the concept of reinforcement cost is straightforward, this component of the cost of transmission transactions is very difficult to evaluate. Technically, the problem involves the solution of the least cost transmission expansion problem in response to a new transaction.

3.3.4.4 Existing System Cost

All the aforementioned components of the cost of wheeling transaction are directly caused by the transaction. These are the direct costs of providing transmission services. There are collectively called the incremental cost of transmission transaction.

The existing system cost of a wheeling transaction corresponds to the cost of existing transmission system that is to be allocated to that transaction. The cost of existing transmission is the cost associated with the investment made in building and the expenses incurred in maintaining the existing transmission system and for example includes the embedded and the O&M costs of the transmission system hardware. It is important to note that a wheeling transaction does not actually cause any new costs involving the use of existing transmission facilities. These facilities have already been built and their costs already incurred. Hence, the actual question is not of incurred costs but allocation of the cost of existing transmission system to those who use the system.

Because the cost of existing transmission system is generally large, the existing system cost of a transmission transaction is usually the largest component of the overall cost of the transaction. For this and other historical reasons, this cost has received the most attention from regulatory agencies overseeing revenue collection by the utilities. Here the major issues are:

- to whom the cost of existing transmission system should be allocated? There is no clear consensus on this issue. Some economists suggest that the cost of existing transmission system should not be allocated to new wheeling transactions. Some believe that the cost of existing transmission system should be allocated to all users of the transmission system. Most interested parties however, consider that the cost of existing transmission system must be shared by all customers of firm wheeling transactions. The basis for this consideration is the obligation for the utility to reserve transmission capacity for firm wheeling transactions at all times.

· How should the cost of existing transmission system be allocated among the wheeling transactions? The common solution here has been to first define and evaluate a transmission system capacity used measure for the wheeling transactions.

This measure is then used to allocate the cost of existing transmission system among users of the transmission system. Several transmission system capacity used measures are already in use or being proposed by the industry. The simplest and most popular capacity use measure is the power demand associated with transaction. This method is known as the 'postage stamp' or 'rolled-in method'. Other proposed capacity use measures are power flow based and reflect the actual operation of the transmission system. One such approach is the "MW-Mile methodology" which proposes the MW-mile usage of the transmission system, as the capacity use measure [8]. Both methods have been described in Section 3.4. The existing system cost component of a wheeling transaction is always positive. For instance, consider there are 3 transactions involved in the transmission system. All transactions are firm. The transaction T2 is being studied. The cost of existing facilities is allocated to the three transactions based on the MW-mile capacity use of each transaction. Table 3.5 presents the results of the analysis.

Table 3.5 Allocating the Cost of Existing Transmission System based on the MW-mile Methodology.

TRANSACTION	MW-MILE USE (MW-mile)	% OF THE COST OF EXISTING TRANSMISSION SYSTEM
Transaction T1	306516	73.53
Transaction T2	12462	2.99
Transaction T3	97889	23.48
Total	416867	100

Assuming that the cost of existing transmission system is £ 40000000.00 /yr, thus the existing system cost component of transaction T2 will be £1196000/yr (2.99% of £ 40000000.00 /yr).

3.3.5 Wheeling Charges

Wheeling charge is the charge for the use of the transmission services. The purpose of this charge is to recover the transmission revenue requirement (TRR). TRR is the amount of money a Transmission Owners (TOs) must collect from its users to pay all operating and capital costs for the transmission system, including a fair return on its investment. The charges also collected to ensure the continued economic and reliable use of the existing transmission system. Furthermore, it provides motivation for the installation of new transmission line that will be needed in the future.

The methodology by which the cost of wheeling is computed is a high priority problem throughout the power industry due to the growth in transmission facilities. The key issue underlying the wheeling debate is the determination of the rates a wheeling utility should charge [12]. Further issues related to wheeling such as; who should be the benefiters of wheeling; what cost-risks should the wheeling utility recover; what types of wheeling are socially desirable and should wheeling rate be modified in near real time to reflect changes in operating conditions. There are wheeling charge calculation concepts that have been proposed in the literature using marginal cost pricing and embedded cost pricing [13,14]. However, the most commonly method used to price the transmission services throughout the utility industry is based on embedded cost methods. These methods usually determine the wheeling rates based on concepts such as postage stamp, contract path (or red line), and megawatt mile methods. These methods have their pros and cons in determining wheeling charges and are discussed in details in the following section.

3.4 Wheeling Charges based on Embedded Cost Methods

As mentioned in Chapter 2, the embedded cost methods are commonly used throughout the utility industry to allocate the cost of transmission services. These methods have been suggested to allocate such pricing since the application of marginal cost in pricing the transmission services has shown not effective mainly due to revenue reconciliation problems.

In these methods, transmission system is assumed to be one integrated facility and all costs to meet transmission system revenue requirements are distributed across all customers.

These methods consider the embedded capital costs and average annual operation costs of existing facilities while determining the transmission costs. For each transmission line, the net plant cost is calculated for each year of the transaction period. This is calculated using the replacement cost, average service life and depreciation reserve of the line capital investment. Subsequently, the annual fixed charge rate is calculated for each year.
Based on these calculations, four different embedded costs of wheeling methods could be used namely, postage stamp method, contract path method, distance based MW-mile method and power flow based MW-mile method.

3.4.1 Postage Stamp Method

The postage stamp method or rolled-in embedded method assumes that the entire transmission system is used in wheeling, irrespective of the actual transmission facilities that carry the transaction. The cost of wheeling as determined by this method is independent of the distance of the transaction, which is the reason that the method is also called the Postage Stamp Method. This method allocates wheeling charges based on the magnitude of the transacted power. The magnitude of the transacted for a particular transaction is usually measured at the time of system peak load condition. The wheeling charge for this scheme can be written mathematically as;

$$R_t = TC \bullet \frac{P_t}{P_{peak}} \qquad (3.1)$$

where R_t wheeling charge for transaction t

TC total transmission cost

P_t power of transaction

P_{peak} system peak load

In general, the postage stamp method is considered sending incorrect economic signals since they ignore the state of the actual system operation. For instance, a transaction with generation and load in short electrical distance would pay the same access charge as the one with long electrical distance as long as they stayed within the same zone.

Moreover, this method has been severely criticized by supporters of open access because it represents pancaking of rates and has the tendency of substantially increasing transmission costs. However the calculation is very easy and therefore often used throughout the utilities industries. A comprehensive treatment to improve this method can be found in [15, 16].

3.4.2 Contract Path Method

In this method, a specific path between the points of injection and receipt is artificially selected for a wheeling transaction. This path is called the "contract path" and is selected by transmission owner and the wheeling customer to identify the transmission facilities that are actually involved in a transaction without performing a power flow. Once the contract path has been determined all or a part of the embedded capital costs related to the specified path are assigned to the transaction. The wheeling charge using this scheme can be calculated using equation (3.2)

$$R_t = \sum_k TC_k \bullet \frac{P_t}{\overline{P}_k} \qquad (3.2)$$

where k the transmission lines in path

TC_k the transmission cost in path

$\overline{P}_k$ transmission line capacity in path (MW)

Compared with the postage stamp method the contract path concept takes the distance between injection and receipt into account. However, this method is likely to provide uneconomic signals since the contract path is fictitious and not dependent on the real network situation. The actual path may differ in terms of distance and affected lines. Transaction cost may strongly vary and therefore cause cost as well as network inefficiencies. Contract-path method is less commonly used in pricing the transmission services.

3.4.3 Distance based MW-mile Method

The method assigns the embedded wheeling charges to the customers based on the airline distance (mile distance) between the point of injection and receipt and the magnitude of transmitted power. The wheeling charge determined using for this scheme can be expressed mathematically as [17]

$$R_t = TC \bullet \frac{PX_t}{\sum_i PX_i} \qquad (3.3)$$

with

$$PX_t = DT \bullet PM \qquad (3.4)$$

where PX_t = MW-mile value

DT = airline distance in mile

PM = wheeling power in MW

This method also neglects the actual system operation. The airline distance does not indicate the actual transmission facilities involved in the transaction. Hence, it is likely to give incorrect economic signals to the wheeling customers.

3.4.4 Power Flow based MW-mile Method

The power flow based MW-mile method is the first concept to consider the actual system conditions using power flow analysis, forecasted loads and the generation configuration [17]. This method allocates the charges for each transmission facility to transmission transactions based on the extent of use of that facility by these transactions. The allocated charges are then added up over all transmission facilities to evaluate the total price for use of transmission system [19]. This method takes into account parallel power flow and eliminates the contract path method that transmission owners were not compensated for using their facilities. The method is complicated because every change in transmission lines or transmission equipment requires a recalculation of flows and charges in all lines. However many economists prefer this method because it directly encourages the efficient use of the transmission facility and the expansion of the system. Several sub-concepts to this method have been discussed in [17,18] and are illustrated below.

3.4.4.1 MW-mile Method (MWM)

In this method, the power flows on each circuit (line) caused by the generation/load pattern of each customer is calculated on a power flow model. The costs of transaction are then allocated in proportion to the ratio of power flow and circuit capacity. Equation (3.5) shows the cost allocation principle of the method.

$$R(u) = \sum_{all\,k} C_k \frac{|f_k(u)|}{\overline{f_k}} \qquad (3.5)$$

where $R(u)$ allocated cost to customer u

C_k cost of circuit k

$f_k(u)$ k-circuit flow caused by customer u

$\overline{f_k}$ k-circuit capacity

Total cost = $\sum_{all\,k} C_k$

Since this method allocates transmission cost through a ratio of the power flows caused by the customers and the line capacity not all embedded costs may be recovered. The total power flows are usually smaller than the line capacities. The method does not cover the cost for holding reserve capacities. Only the 'base case' is evaluated. Although this method overcomes some limitations of the other two previous methods but has been criticised as having no solid grounding in economic theory.

3.4.4.2 Modulus Method (MM)

In this method, the line capacities in MW-mile method are replaced by the sum of the absolute power flow caused by all customers in order to fully recover the embedded cost. Equation (3.6) depicts the charging concept for this method.

$$R(u) = \sum_{all\ k} C_k \frac{|f_k(u)|}{\sum_{all\ s} |f_k(s)|} \qquad (3.6)$$

This method, which also known as usage method, assumes that all customers have to pay for the actual capacity used and for the additional reserve. This reserve may be due to the need of system meeting reliability, stability and security criteria or due to system adjustments (i.e., due to planning "error" caused by the inherent uncertainties of the planning process). However, there is no incentive to the customer that alleviates the circuit load, improving the system performance and/or postponing transmission investments.

3.4.4.3 Zero Counter Flow Method (ZCM)

In this method, the customers whose power flow is in opposite direction of the net flow are not being charged. Only the customers that use the circuit in the same direction of the net flow (which will be denoted as the positive direction) pay in proportion to their flow. Equation (3.7) shows the allocation charge concept for this method.

$$R(u) = \sum_{all\,k} C_k \frac{f_k(u)}{\sum_{all\, s \in \Omega_{k+}} f_k(s)} \qquad \text{for } f_k(u) > 0$$

$$R(u) = 0 \qquad\qquad \text{for } f_k(u) \le 0 \qquad\qquad (3.7)$$

where Ω_{k+} set of customers with positive flows on circuit k

This method assumes that the net flow reduction is beneficial even if there is already an "excess" installed capacity. Moreover, for the light loaded circuit, there is a discontinuity on the charges when the net flow changes the direction.

3.5 Wheeling Charge Calculation Methodologies used in Transmission Utilities

This section discusses wheeling charge calculation methodologies currently used by the transmission utilities to determine the charge for the transmission services. Four transmission utilities; National Grid Company (NGC), United Kingdom, Electricity Supply Board National Grid (ESBNG), Republic Ireland, Electric Reliability Council of Texas Interconnection System (ERCOT), Texas, USA and Southwest Power Pool, Arkansas, USA (SPP) have been selected to investigate their similarity in the implementation of wheeling charges methodology. Transmission service costing aspects such as the cost allocation method used to recover the transmission cost, the allocation method used to estimate the contribution of the usage of capacity of transmission network and the pricing method used to calculate the wheeling charge and the recovery charge will be analysed through the numerical example.

3.5.1 NGC, England and Wales

NGC is the electricity transmission company for England and Wales that owns, operates and maintains the high voltage transmission system that connects generators with major users and distribution companies. In the context of transmission service charges, NGC levies two different charges; transmission network use of system charges and connection charges. The transmission network use of system charges reflects the cost of installing, operating and maintaining the transmission system while the connection charges are designed to recover the costs incurred in providing assets, which afford connection of one or a group of users to the transmission system, with a reasonable rate of return. As mentioned in section 3.2.3.1, NGC has levy the transmission network use of system charges (TNUoS) tariff to recover the Maximum Allowed Revenue (MAR) as set by the Price Control net of the revenue from pre-vesting connection charges. This tariff comprises two separate elements [20];

1) a locational varying element derived from the DC Load Flow Investment Cost Related Pricing (DCLF ICRP) based transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations.
2) a non-locational varying element related to the provision of residual revenue recovery.

The function of this tariff model is to generate tariffs that reflect, as closely as possible, the costs incurred by the NGC in investment in the transmission business. The process for calculating the tariff can be divided to several stages:

i) Calculation of nodal marginal km via DCLF ICRP based transport model
ii) Calculation of zonal marginal km
iii) Derivation of the Final £/kW tariff

i) Calculation of nodal marginal km via DCLF ICRP transport model

The underlying methodology for the locational element of the TNUoS tariffs uses the DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1MW injection to the system.

The transport model requires a set of inputs representative of peak conditions on the transmission system such as nodal generation and demand information, transmission circuits between these nodes, associated lengths of these routes and the length of which is overhead line or cable and their voltage level, routes with significant spare capacity and an identification of a reference node. The voltage level information is required in order to determine the circuit expansion factors. The circuit expansion factors reflect the difference in cost between (i) cabled routes and overhead line routes, (ii) 275kV routes and 400kV routes, and (iii) uses 400kV overhead line as the base (i.e. 400kV overhead line circuit expansion factor = 1). The circuit lengths included in the DCLF ICRP transport model are solely those, which relate to assets defined as 'use of system' assets.

A reference node is required as a basis point for the calculation of marginal costs. For the purposes of DCLF ICRP, the reference node is currently at Pelham GSP. The transport model takes the inputs described above and firstly scales the nodal generation capacity uniformly such that total national generation equals total national ACS demand. The model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity. Then it calculates the resultant total MWkm, using the relevant circuit expansion factors as appropriate.

Using this baseline network cost, the model calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MWkm of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node. The marginal km cost for demand at each node is equal and opposite in sign to the nodal marginal km for generation. Note the marginal km costs can be positive and negative depending on the impact the injection of 1MW of generation has on the total circuit km.

The DCLF ICRP transport model described above determines power flow on a defined network for a given market background using the reactance (X) values of the circuits comprising the network. A number of simplifying assumptions were made in defining the "simplified DCLF" algorithm, namely;

a) security is not considered i.e. the network is treated as intact with impact of contingencies not assessed.

b) operational arrangements are not considered i.e. substations are run solid and line limits do not constrain power flows (this latter aspect is unlikely to be a factor at peak demand in any event)

c) R is assumed to be much smaller than X for each circuit on a per unit (pu) basis

d) The phase angles (θ) in radians are assumed to be small

Given the above assumptions, the power equation, which forms the basis of the simple DCLF algorithm used in the DCLF ICRP Transport Model is[21];

$$P = \frac{\theta}{X} = Y \cdot \theta \qquad (3.8)$$

where

P	=	power
θ	=	phase angle
X	=	reactance
Y	=	1/X

By considering a multi-node network, the DCLF ICPR Transport Model can be written in matrix equation as follows;

$$[P]=[Y]\cdot[\theta] \qquad (3.9)$$

where

P = matrix of power injections (plus or minus) for all nodes

θ = matrix of effective phase angles for all circuits connected to each node

Y = matrix of admittance values for all circuits

Hence the individual phase angles (θ) for each node can be solved using the following equation;

$$[\theta]=[Y]^{-1}\cdot[P] \qquad (3.10)$$

However because the matrix Y is a singular matrix, it can only be inverted by removing a row in the matrix. The algorithm removes the row that maximises the efficiency of the calculation, which should be that relating to the most interconnected node (unless forced to do an alternative specific node by the user) and this node is defined as the reference node, with its nodal θ set to zero.

$$[\theta]=[Y']^{-1}\cdot[P] \qquad (3.11)$$

Given this calculation the DCLF algorithm can then determine the network power flows for nodes m-n by considering the following equation;

$$P_{mn}=Y_{mn}\cdot(\theta_m-\theta_n) \qquad (3.12)$$

In this way the DCLF algorithm derives the baseline power flows for the entire network. Example below shows the DCLF algorithm is used to calculate the nodal marginal for 3-node network.

3.5.1.1 Example of DCLF Transport Model

Consider the following 3-node network

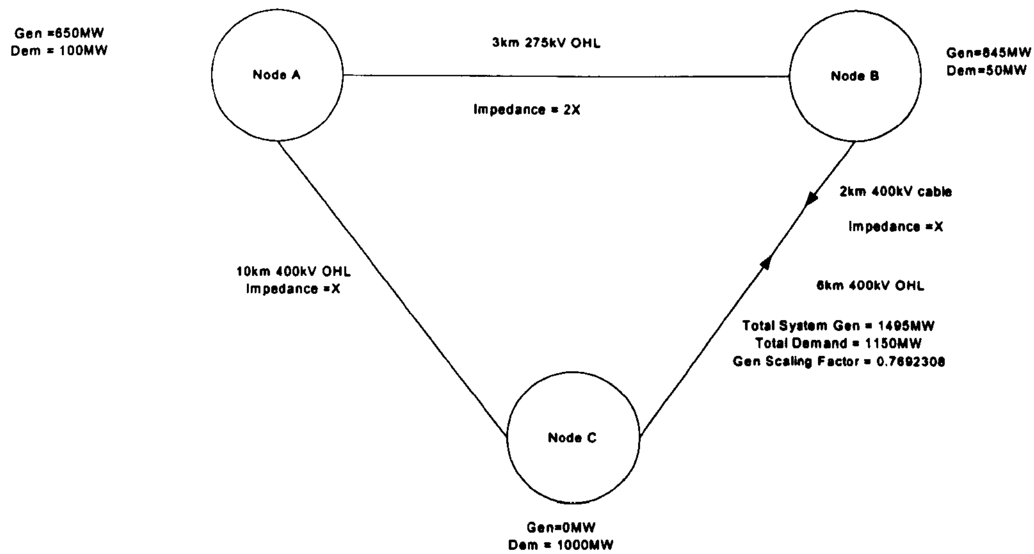

Figure 3.2 Three Node Network

Figure 3.2 shows the three nodes network used to illustrate the transport model concept. In the model the total demand and total generation need first to be matched by scaling uniformly the nodal generation down such that total system generation equals total system demand. For instance;

Node A Generation = 1150/1495 * 650MW = 500MW

Node B Generation = 1150/1495 * 845MW= 650MW

This gives the following balanced system as shown in Figure 3.3.

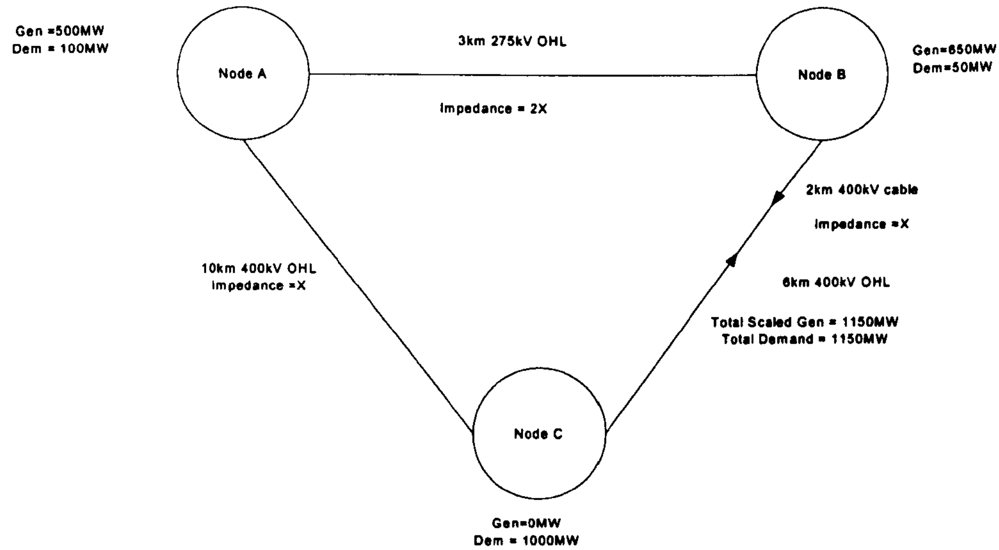

Figure 3.3 Three Node Network with Balance System

Assuming Node A is the reference node, each circuit has impedance X. The 400kV cable circuit expansion factor is 10, the 400kV overhead line circuit expansion factor is 1 and the 275kV overhead line circuit expansion factor is 2, the DCLF transport algorithm calculates the base case power flows as follows:

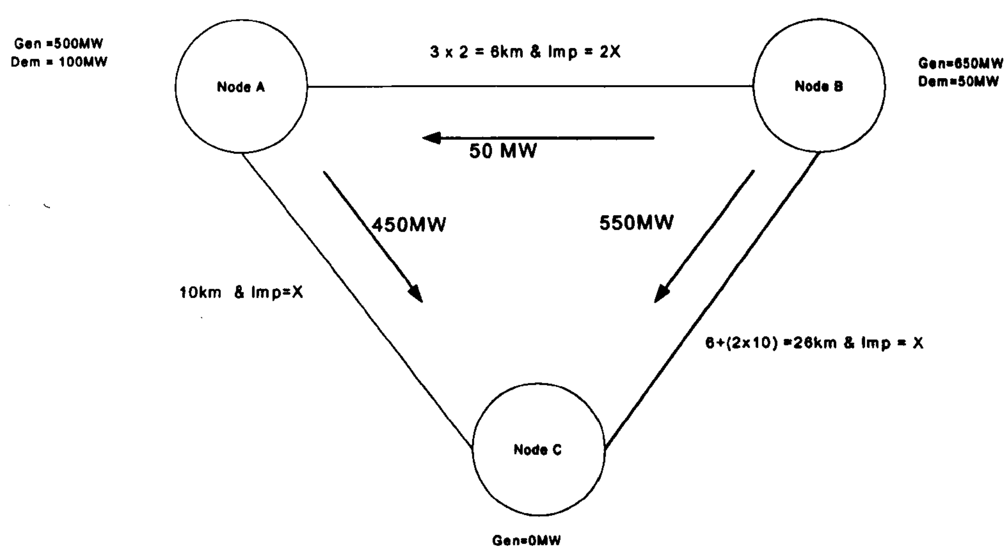

Figure 3. 4 Three Node Network (Apply Circuit Expansion Factor)

Using equation (3.9)

$$\begin{bmatrix} 0.4 \\ 0.6 \\ -1 \end{bmatrix} = \begin{bmatrix} 1.5 & -0.5 & -1 \\ -0.5 & 1.5 & -1 \\ -1 & -1 & 2 \end{bmatrix} \bullet \begin{bmatrix} \theta_A = 0 \\ \theta_B \\ \theta_C \end{bmatrix}$$

Since matrix Y is singular it is necessary to reduce the matrix by removing the row and column of the terms of reference bus

$$\begin{bmatrix} 0.6 \\ -1 \end{bmatrix} = \begin{bmatrix} 1.5 & -1 \\ -1 & 2 \end{bmatrix} \bullet \begin{bmatrix} \theta_B \\ \theta_C \end{bmatrix}$$

Using equation (3.11), the phase angle for each node can be calculated

$$\begin{bmatrix} \theta_B \\ \theta_C \end{bmatrix} = \begin{bmatrix} 1.0 & 0.5 \\ 0.5 & 0.75 \end{bmatrix} \bullet \begin{bmatrix} 0.6 \\ -1 \end{bmatrix} = \begin{bmatrix} 0.1 \\ -0.45 \end{bmatrix}$$

Hence, the base line power flow for entire network can be determined using equation (3.12)

$$P_{AB} = (\theta_A - \theta_B) \cdot Y_{AB} = (0 - 0.1) \cdot 0.5 = -0.05pu = -50MW$$
$$P_{AC} = (\theta_A - \theta_C) \cdot Y_{AC} = (0 - (-0.45)) \cdot 1 = 0.45pu = 450MW$$
$$P_{BC} = (\theta_B - \theta_C) \cdot Y_{BC} = (0.1 - (-0.45)) \cdot 1 = 0.55pu = 550MW$$

It can be seen that nodes A and nodes B export the power, whilst node C imports the power. Hence, the DCLF algorithm derives flows to deliver export power from nodes A and B to meet demand at node C.

Total cost for base case = (450 x 10) + (50 x 6) + (550 x 26)= 19100 MWkm.

We then inject 1MW of generation at each node with a corresponding 1MW off-take (demand) at the reference node and recalculate the total MWkm cost as shown in Figure 3.5. The difference in cost from the base case is the marginal km or shadow cost. For example, to calculate the marginal km at node C

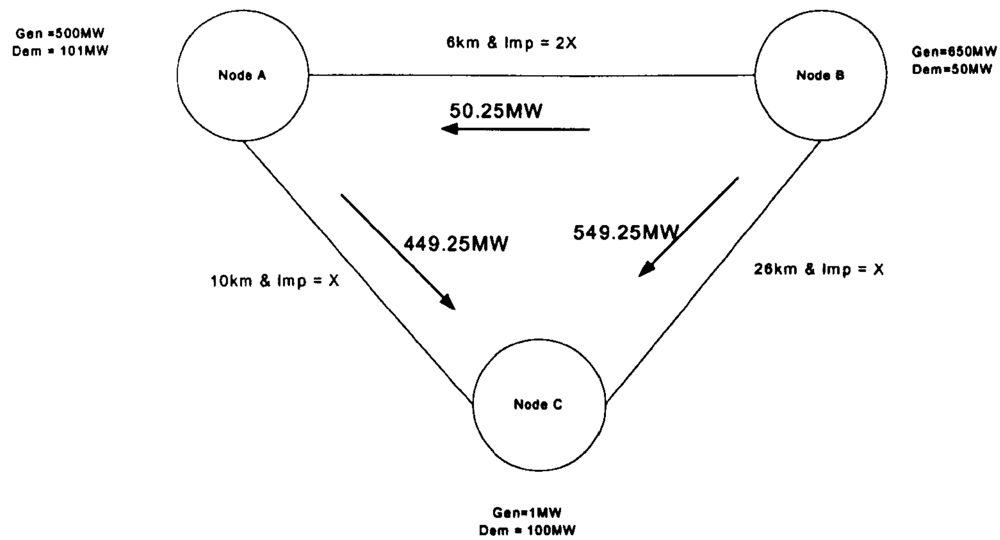

Figure 3.5 Three Node Network (Shadow Cost)

Total cost at Node C = (449.25 x 10) + (50.25 x 6) + 549.25 x 26) = 19074.5 MWkm. Thus the overall cost has reduced by 25.5 (i.e. the marginal km = -25.5)

ii) Calculation of zonal marginal km

The nodal marginal km calculated are amalgamated into zones by weighting them by their relevant generation or demand capacity. For instance, the zonal marginal for generation is calculated as

$$WNMkm_j = \frac{NMkm_j * Gen_j}{\sum_{j \in Gi} Gen_j} \qquad (3.13)$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j \qquad (3.14)$$

where

Gi	=	Generation zone
j	=	Node
NMkm	=	Nodal marginal km from transport model
WNMkm	=	Weighted nodal marginal km
ZMkm	=	Zonal Marginal km
Gen	=	Nodal Generation from the transport model

If there is no generation in a particular zone, a simple average of the nodal marginal km is calculated as

$$ZMkm_{Gi} = \frac{\sum_{j=Gi} NMkm_j}{nj} \qquad (3.15)$$

where

nj	=	number of nodes in generation zone Gi

Meanwhile, the zonal marginal km for demand are calculated as follows;

$$WNMkm_j = \frac{-1 * NMkm_j * Dem_j}{\sum_{j \in Di} Dem_j} \qquad (3.16)$$

$$ZMkm_{Di} = \sum_{j \in Di} WNMkm_j \qquad (3.17)$$

where

Di	=	Demand zone
Dem	=	Nodal Demand from transport model

iii) Derivation of £/kW tariff

The zonal marginal km are then converted into costs by the application of the expansion constant and the locational security factor. The expansion constant which is expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1MW over 1km. Its magnitude is derived from the projected cost of 400kV overhead line that NGC would expect to incur, including an estimate of the cost of capital, if required for future system expansion. The steps taken to derive the expansion constant are as follows [26]:

i) For each year, the NGC determines its projected £/MWkm cost of 400kV overhead line based on manufacturers' budgetary prices, contracts let and lead tenders. A range of overhead line types is used and the types are weighted by recent usage on the transmission system
ii) At the beginning of a price control period, an expansion constant figure using a 5 years average is calculated
iii) This average figure sets the expansion constant for the first year of the control period and for each subsequent year within the price control period, the value is increased by RPI
iv) Allowances for engineering and interest costs are added
v) The capital cost figures are converted into annuities
vi) An addition is made for the cost of maintenance

As an illustration the expansion constant used for 2004/05 was £9.51/MWkm. Meanwhile, the locational security factor is calculated by comparing the results of a secure DCLF with the results of simple DCLF transport model. This calculates the nodal marginal costs where peak demand can be met despite N-1 and N-2 contigencies (simulating single and double circuit faults) on the network. The calculation of nodal marginal costs is essentially identical to the process outlined above except that the secure DCLF study increases line capacity where appropriate to ensure intact load flows under network contingencies. The maximum nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor. As an illustration, the locational security factor derived for 2004/05 is 1.9.

Equation (3.18) shows the initial transport tariff for generation can be calculated by simply multiplying the zonal marginal km (ZMkm) with the expansion constant and locational security factor

$$ZMkm_{Gi} \times EC \times LSF = ITT_{Gi} \qquad (3.18)$$

where

$ZMkm_{Gi}$	=	zonal marginal km for each generation zone
EC	=	expansion constant
LSF	=	locational security factor
ITT_{Gi}	=	initial transport tariff (£/MW) for each generation zone

Similarly for demand, the initial transport tariff can be calculated with the manner as shown in equation (3.18).

$$ZMkm_{Di} \times EC \times LSF = ITT_{Di} \qquad (3.19)$$

where

$ZMkm_{Di}$	=	zonal marginal km for each demand zone
EC	=	expansion constant
LSF	=	locational security factor
ITT_{Di}	=	initial transport tariff (£/MW) for each demand zone

A single additive constant C is calculated by simultaneous equations and then is added to the zonal marginal km for both generation and demand to achieve the 'correct' generation/demand revenue split. Hence, a corrected (£/MW) transport tariff (CTT) is calculated as follows:

$$(ZMkm_{Gi} + C) \times EC \times LSF = CTT_{Gi} \qquad (3.20)$$

$$(ZMkm_{Di} - C) \times EC \times LSF = CTT_{Di} \qquad (3.21)$$

so that

$$\sum_{Gi=1}^{15} (CTT_{Gi} \times G_{Gi}) = CTRR_G \qquad (3.22)$$

$$\sum_{Di=1}^{15} (CTT_{Di} \times D_{Di}) = CTRR_D \qquad (3.23)$$

where

CTTR = "Generation/Demand split" corrected transport revenue

C = "Generation/Demand split" correction constant (in km)

G_{Gi} = Total forecast generation for each generation zone (based on confidential User forecasts

D_{Di} = Total forecast Meter Triad Demand for each demand zone (based on confidential User forecasts

In order to ensure adequate revenue recovery, a constant non-locational residual tariff for generation and demand is calculated. Residual Tariff is calculated which includes infrastructure substation asset costs. It is added to the corrected transport tariffs so that the correct generation/demand revenue split is maintained and the total revenue recovery is achieved. Equations (3.24) and (3.25) depict the residual tariff for generation and demand.

$$RT_G = \frac{[(1-p) \times TRR] - CTRR_G}{\sum_{Gi=1}^{15} G_{Gi}} \qquad (3.24)$$

$$RT_D = \frac{(p \times TRR) - CTRR_D}{\sum_{Di=1}^{12} D_{Di}} \qquad (3.25)$$

where

RT	=	residual tariff (£/MW)
TRR	=	TNUos Revenue Recovery target for a particular year
p	=	proportion of revenue to be recovered from demand

As a result, the final Transmission Network use of system tariff (TNUoS) for generation and demand can be calculated as the sum of the corrected transport tariff and the non-locational security as depicted in equation (3.26) and (3.27) respectively.

$$FT_{Gi} = \frac{CTT_{Gi} + RT_G}{1000} \qquad (3.26)$$

$$FT_{Di} = \frac{CTT_{Di} + RT_D}{1000} \qquad (3.27)$$

where

FT	=	final TNUoS tariff expressed in £/kW

The example below shows the calculation of zonal marginal for generation for zone 7 in the NGC network.

3.5.1.2 Example of Zonal Generation Tariff

Let us consider all nodes in generation zone 7: Rest of Mids & Anglia [20]. Table 3.6 below shows a sample output of the transport model comprising the node, the marginal km of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand and the demand sited at the node.

Table 3.6 Sample Output of Transport Model

Genzone	Node	Nodal Marginal km	Scaled Generation
7	BRAI4A	105.37	0
7	BRFO40	118.89	0
7	BURW40	110.86	0
7	EASO40	112.99	552.02
7	GREN40-EME	79.56	321.55
7	GREN40-EPN	79.56	0
7	NORW40	108.96	332.64
7	SIZE40	157.43	1338.48
7	SPLN40	186.18	0
7	SUND40	35.14	0
7	WALP40_EME	164.24	0
7	WALP40_EPN	164.24	1257.70
7	WYMO40	74.74	0
	TOTALS		3802.39

The procedure to calculate the generation tariff would be carried out as follows:

a) Calculate the zonal marginal km for generation.

We first calculate the weighted generation nodal shadow costs using equation (3.13). The sum of the generation weighted nodal shadow cost gives a zonal marginal km for generation using equation (3.14).

For instance, for node WALP40_EPN, the generation weighted nodal marginal km can be calculated as

$$WNMkm_{WALP40\_EPN} = \frac{164.24 \times 1257.70}{3802.39} = 54.32$$

The generation weighted nodal marginal km for other nodes in zone 8 can be calculated in the same way. Table 3.7 depicts the results of generation weighted nodal shadow cost for the rest of the nodes.

Table 3.7 Generation Weighted Nodal Shadow Cost

Genzone	Node	Nodal Marginal km	Scaled Generation (MW)	Gen Nodal km	Weighted Marginal
7	EASO40	112.99	552.02	16.40	
7	GREN40_EME	79.56	321.55	6.73	
7	NORW40	108.96	332.64	9.53	
7	SIZE40	157.43	1338.48	55.42	
7	WALP40_EPN	164.24	1257.70	54.32	
	TOTALS		3802.39		

b) The sum of the generation weighted nodal shadow cost gives a zonal marginal km for generation using equation (3.14)

$$ZMkm_{Gi} = (16.40 + 6.73 + 9.53 + 55.42 + 54.32)\text{ km} = \mathbf{142.40\ km}$$

c) Modify the zonal marginal km above by the generator/demand split correction factor to ensure the 27:73 (approx.) split of revenue recovery between generation and demand is retained. Then calculate the corrected transport tariff using equation (3.20).

For zone 7 the modified zonal marginal km would be;.

$$142.40 + (-127.61) = \mathbf{14.79\ km}$$

d) Calculate the corrected transport tariff by assuming an expansion constant of £9.51/MWkm and a locational security factor of 1.9:

$$CTT_{Gi} = \frac{14.79km \times £9.51/MWkm \times 1.9}{1000} = £0.27/kW$$

e) Calculate the residual tariff: This is calculated by taking the total revenue to be recovered from generation (calculated as 27% of total TNUoS target revenue for the year) less the revenue which would be recovered through the generation transport tariff divided by total expected generation. Assuming a total revenue to be recovered from TNUoS is £785m, the total recovery from the generation would be (27% x £785m) = £211.95m. Assuming a total recovery from generation transport tariffs is £45m and total forecast chargeable generation capacity is 62000MW, the Generation residual tariff would be:

$$RT_{Gi} = \frac{£211.95m - £45m}{62000MW} = £2.69/kW$$

f) calculate the final TNUoS generation tariff for zone 7

FT_{Gi} = £0.27/kW + £2.69/kW = **£2.96/kW**

Note that the model derived above is the new proposed model, which will be implemented by the NGC in April 2004. This type of model calculates the flow of power on the transmission system, taking into account the impedance of each circuit of the system. For the same background of generation and demand, this model is expected to produce greater locational differentials than the basic transport model, which is based on 'travelling salesman' model. This previous model uses a transport algorithm to find the shortest network in MWkm to meet the nodal demand.

Although the DC load flow model is still an approximation of real system flows, but NGC believes, it will provide a better representation of those real flows on the network than the basic transport model used in the ICRP methodology.

3.5.2 ESBNG, Republic Ireland

In Republic Ireland, ESB National Grid (ESBNG) is the business unit in Electricity Supply Board (ESB) responsible for operating the power system. In the context of transmission related charges, ESBNG has introduced two different charges to recover the revenue requirement. These charges comprise network charges and system services charges which are levied to both generation and demand users connected directly to the transmission system or indirectly via the distribution system.

Network charges are primarily related to recovery of wires costs or fixed costs. These recover the costs for the use of the transmission system infrastructure for the transportation of electricity in Ireland. As shown in Table 3.1, 25% of the costs recovered from generation and the remaining 75% from the 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. Figure 3.6 shows the transmission related charges for ESBNG transmission business [22].

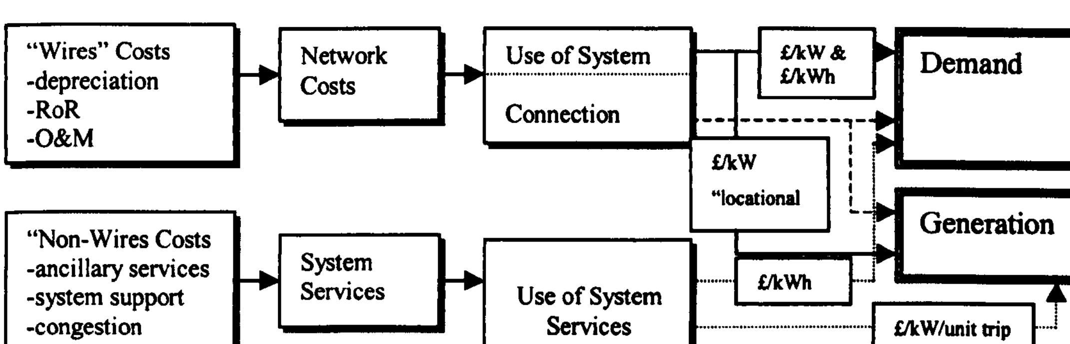

Figure 3.6 Transmission Related Charges for ESBNG Transmission Business

Like NGC, ESBNG has also designed the transmission use of system charges tariff based on two separate elements. Firstly, a locational use of system charges derived using the Reverse MW-mile approach. These charges, which are capacity based and used for firm access tariffs, provide efficient siting signals to new generator in support of an overall efficient transmission system. A key feature of the Reverse MW-Mile approach is that generators, which offset flows, are rewarded, by crediting counter-flows. This could encourage generators to locate in areas of the country, which would reduce the need to reinforce the transmission system and reduce the cost associated with transmission constraints.

Secondly, a postage stamp capacity charge based on per kW is used to recover the remaining total transmission cost since the locational use of system charges is not sufficient to remunerate this cost. This cost, which is associated with unused capacity, is distributed among the generators. There are three main steps involved in deriving generation use of system charges:

i) DC Load Flow calculation
ii) Calculate costs associated with each circuit
iii) Deriving generation locational charges.

i) DC Load Flow calculation

A dc load flow analysis is used to identify the direction of the flow in each circuit. This analysis requires the specification of generation and demand at each point on the network. The formulation of the linear power flow (DC approach) can be derived as follows:

$$P_{ij} = x_{ij}^{-1}.\theta_{ij} \qquad (3.28)$$

where

P_{ij} = circuit flow (pu)

x_{ij} = circuit reactance (pu)

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

$$P_i = \sum x_{ij}^{-1}.\theta_{ij}$$
$$P_i = \left(\sum x_{ij}^{-1}\right)\theta_i + \left(\sum - x_{ij}^{-1}\right)\theta_j \qquad (3.29)$$

where

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

In matrix form

$$[P] = [B][\theta] \qquad (3.30)$$
$$B_{ij} = -x_{ij}^{-1}$$
$$B_{ii} = \sum x_{ij}^{-1}$$

where

$[B]$ = the bus susceptance matrix

However, the matrix is singular, so it doesn't have inverse. Consequently, it is necessary to reduce the matrix by the terms of the swing bus (bus1)

$$[P] = [B'][\theta] \qquad (3.31)$$

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

$$[\theta] = [B']^{-1}.[P] \qquad (3.32)$$

The flow in each circuit is obtained by the expression

$$P_{ij} = -B_{ij}.\theta_{ij} \qquad (3.33)$$

In this approach, the flow is called dominant if the circuit flow caused by the generator and the total circuit flows in a circuit are in the same direction. On the other hand, the flow is called reverse if the flows are in opposite direction to the dominant flow. To determine whether flows are dominant or reverse, the total flow in the circuit (i.e. base case scenario) minus the flow without the generator under study.

$$\Delta P_{ij}^{i} = P_{ij}^{T} - P_{ij}^{T-i} \qquad (3.34)$$

where

P_{ij}^{T} = total circuit flow for bus i-j caused by all generators

P_{ij}^{T-i} = circuit flow for bus i-j caused by all generators except generator at bus i

Only the generator who is responsible for increasing the flow has to pay the charge while those reducing the flow of the circuit receive the credit.

ii) Calculate costs associated with each circuit

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.

iii) Deriving generation locational charges.

The locational charges for generation can be derived based on the results found from the load flow analysis and costs associated with each circuit. For instance, the locational charges paid by the generator at bus i can be calculated as follows;

$$R_{i} = \sum_{k=1}^{nlin} \frac{c_{k}}{k_{k}} \bullet w_{k}^{i} \qquad (3.35)$$

where

c_k = cost of circuit k

k_k = capacity of circuit k

w_k^i = circuit flow caused by generator i on circuit k

A locational tariff for generator *i*

$$\pi_i = \frac{R_i}{P_{Gi}} \qquad (3.36)$$

where

P_{Gi} = power served by generator *i*

ESBNG also uses the postage stamp to recover the remaining total transmission cost since the locational charge is not sufficient to remunerate this cost. This cost, which is associated with unused capacity, is distributed equally among the generators. The postage stamp tariff (£/kW) can be calculated as follows;

$$PS = \frac{\sum_{k=1}^{nlin} c_k - \sum_{i=1}^{n} R_i}{\sum_{i=1}^{n} P_{Gi}} \qquad (3.37)$$

3.5.2.1 Example

Consider a simple 6 bus system comprising three generator at buses 1, 2 and 5 to serve a total demand of 100 MW at buses 3, 4 and 6 at shown in Figure 3.6. For simplicity the capacity of all circuit is assumed to be 50MW and the annual cost of each circuit is assumed to be €50000. Base 100MVA [23].

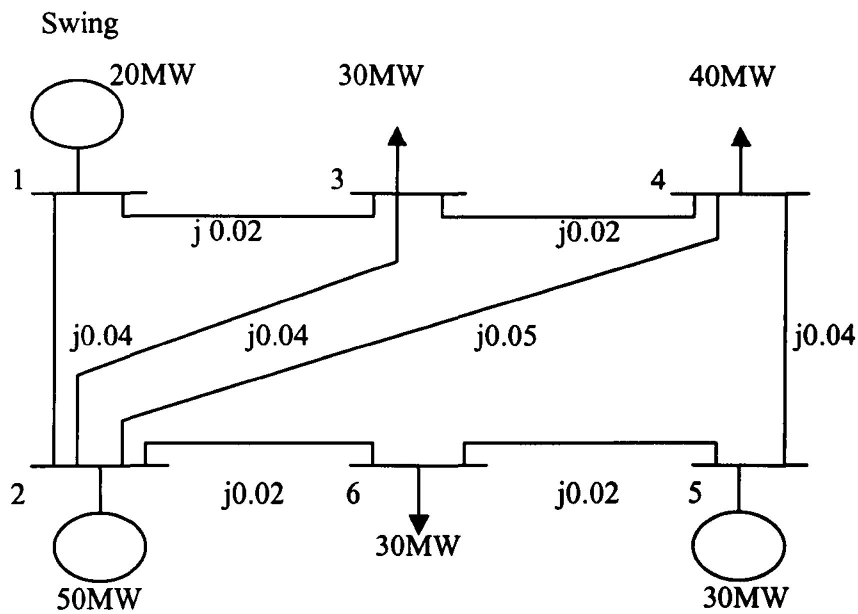

Figure 3.7 A Simple 6-Bus System

The total power flows caused by all generators have to be calculated first. Using equation (3.30)

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

The matrix B is singular so it cannot be inverted. It is necessary to reduce the matrix B by eliminating the row and column associated with the swing bus. Equation (3.31) shows new matrix B denoted as B'.

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

Using equation (3.32), the value of the angle θ_{ij} can be calculated.

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

Finally by using equation (3.33) the power flow in each circuit can be obtained

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

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

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

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

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

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

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

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

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

Using the equations above, the power flow caused for each generator can be calculated in a similar manner. Table 3.8 shows the circuit power flow caused by the generator 1. It is calculated as the total circuit flow minus the circuit flow caused by generators 2 and 5.

Table 3.8 Circuit Power Flow Caused by Generator 1

Circuit	Total circuit flow (MW)	Generator 2 + Generator 5 (MW)	Generator 1 (MW)	Dominant(D) or Reverse(R)
1-2	-3.21	-10.30	7.09	R
1-3	23.21	10.30	12.91	D
2-3	14.81	15.45	-0.64	R
2-4	15.06	13.07	1.99	D
2-6	16.91	11.17	5.74	D
3-4	8.02	1.76	6.26	D
4-5	-16.91	-17.16	0.25	R
5-6	13.09	12.84	0.25	D

The circuit flow caused by the generators 2 and 5 also can be found using the same calculation method used by the generator 1 as shown in Table 3.9 and Table 3.10 respectively.

Table 3.9 Circuit Power Flow Caused by Generator 2

Circuit	Total circuit flow (MW)	Generator 1 + Generator 5 (MW)	Generator 2 (MW)	Dominant(D) or Reverse(R)
1-2	-3.21	4.77	-7.98	D
1-3	23.21	15.23	7.98	D
2-3	14.81	2.83	11.98	D
2-4	15.06	3.50	11.56	D
2-6	16.91	-1.57	18.48	D
3-4	8.02	3.06	4.96	D
4-5	-16.91	-13.43	-3.48	D
5-6	13.09	16.57	-3.48	R

Table 3.10 Circuit Power Flow Caused by Generator 5

Circuit	Total circuit flow (MW)	Generator 1 + Generator 2 (MW)	Generator 5 (MW)	Dominant(D) or Reverse(R)
1-2	-3.21	-0.89	-2.32	D
1-3	23.21	20.89	2.32	D
2-3	14.81	11.33	3.48	D
2-4	15.06	13.55	1.51	D
2-6	16.91	24.22	-7.31	R
3-4	8.02	11.22	-3.20	R
4-5	-16.91	-3.215	-13.70	D
5-6	13.09	-3.215	16.31	D

Using the results shown in Tables 3.8, 3.9 and 3.10 the cost assumption provided for each circuit, the locational charges for each generator can be calculated by first determine whether the flows are dominant or reverse. The total amount of locational charge for generator 1 can be calculated using equation (3.35) while the locational tariff can be calculated using equation (3.36).

Locational charge for generator 1

$$R_1 = \frac{50\times10^3}{50MW}\cdot(-7.09+12.91-0.64+1.99+5.74+6.26-0.25+0.25)MW$$

$$R_1 = €19170.00$$

Locational tariff for generator 1

$$\pi_1 = \frac{19170.00}{20\times10^3 kW} = €0.9585/kW$$

Table 3.11 shows the locational sign charge for each circuit that should be paid by generator 1.

Table 3.11 Locational Sign Charge for Generator 1

Circuit	Circuit Cost (€)	Circuit Capacity (MW)	Generator 1 (MW)	Dominant (D) or Reverse(R)	Locational Payment(€)
1-2	50K	50	7.09	R	-7090.00
1-3	50K	50	12.91	D	12910.00
2-3	50K	50	-0.64	R	-640.00
2-4	50K	50	1.99	D	1990.00
2-6	50K	50	5.74	D	5740.00
3-4	50K	50	6.26	D	6260.00
4-5	50K	50	0.25	R	-250.00
5-6	50K	50	0.25	D	250.00
				TOTAL	19170.00

Using the same method in determining the flow sign and then applied equations (3.35) and (3.36), the total locational charges and tariffs for generators 2 and 5 can also be obtained respectively.

Locational charge and tariff for generator 2

$$R_2 = \frac{50\times10^3}{50MW}\cdot(7.98+7.98+11.98+11.56+18.48+4.96+3.48-3.48)MW$$

$$R_2 = €62940.00$$

$$\pi_2 = \frac{62940.00}{50\times10^3\,kW} = €1.2588/kW$$

and locational charge and tariff for generator 5

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

R_5 = €29130.00

$$\pi_5 = \frac{29130.00}{30 \times 10^3 kW} = €0.9710/kW$$

Table 3.12 Generation Locational Charges

Bus Number	Generation (MW)	Locational charge tariff (€/kW)	Locational Charge (€)
1	20	0.9585	19170
2	50	1.2588	62940
5	30	0.9710	29130
Total	100		111240

Table 3.12 shows the generation locational charges based on Reverse MW-mile approach. As the locational charge approach will not recover the costs of the transmission system, a postage stamp method is applied to recover the transmission cost which is not remunerated. This charge is distributed to all generators.

Transmission revenue for 8 circuit = 8 x 50 x10^3 = €400 x 10^3

The total revenue recovered by locational charges for three generators

= R_1+R_2+R_3

= 19170 + 62940 + 29130

= € 111240

Hence, transmission cost not remunerated

= € 400 x 10^3 - € 111240

= € 288760

The remaining tariff recovered by postage stamp method

$= € 288760/100 \times 10^3$

$= € 2.8876/\text{kW}$

Table 3.13 depicts the total generation payment based on locational payment (Reverse MW-mile approach) and average payment (postage stamp method) in order to recover the transmission revenue.

Table 3.13 Total Generation Payment

Bus Number	Generation (MW)	Locational payment(€)	Average payment(€)	Total Payment (€)
1	20	19170	57750	76920
2	50	62940	144380	207320
5	30	29130	86630	115760
Total	100	111240	288760	400000

Note: In this example, for simplicity, we assumed that generation pay 100% of the costs. However, as mentioned earlier, generation users only pay 25% of the total costs.

3.5.3 ERCOT, Texas

The Electric Reliability Council of Texas, Inc. (ERCOT) is a corporation that administers the state's power grid. The tariff for transmission service in ERCOT is promulgated in the Texas Public Utility Commission Substantive Rules 23.67 and 23.70. [24]. Under the adopted rule all transmission service is either planned or unplanned. Planned service refers to a specified load from designated resources and longer than 30 days in length. Planned service is the service used by a transmission customer of the transmission provider's system for the delivery of power from a customer's planned resources to that customer's load. Unplanned service is between a specified load and specified resource and is 30 days or less in duration and is available subject to the availability of transmission capacity over that required for planned service. In this section, only the tariff for planned service is discussed since it is of greater importance to market participant. In the context of transmission related charges, the total capital cost of the transmission in ERCOT is recovered by two different charge components [24];

i) a postage stamp component that is designed to recover 70% of the TCOS and is based on MW demand at the peak
ii) a component based on allocation according to the vector-absolute megawatt mile (VAMM) method in order to recover 30% of the TCOS.

i) Postage stamp charge

The postage stamp for planned service is charged on the average of the peak load for the four peak months of the year plus as a percentage of the total ERCOT four month coincident peak average. The total demand is divided into 70% of the TCOS to obtain a yearly postage stamp charge in $ per MW. Typically yearly postage stamp charges in Texas are about $500 per MW based on data at the ERCOT in 1997.

ii) VAMM charge

VAMM is the nomenclature used to describe the calculated use of a transmission system for known contractual arrangements that define the planned resources for specified loads in the ERCOT Interconnected System. The VAMM calculation is the calculated impact on a transmission system for a defined generator or group of generators serving a defined load or group of loads. A DC power flow model is used to calculate the flows on all lines due to this demand-generation pairing. The flows are tallied in terms of the MW-miles of transmission flow.

A MW-mile impact of each line of the transmission network is determined by running of each generator–loads pairing and the result obtained from each transaction is compared with the base case. In the VAMM for instant, if the flow on a given line were computed to change from 10MW to 5MW in the opposite direction, the Vector Absolute change would be 15MW.

The MW-miles of all nominations are summed to calculate the total MW-mile "impact" on a transmission owner. The total "impact" is converted to 30% of TCOS to obtain a yearly charge in $ per MW-mile. The VAMM charge for a transaction is based on its MW-mile "impact" times the yearly charge. Typical yearly charges are about $40 per MW-mile. It is important to note that a given MW-mile "impact on a line, whether it actually acts to increase or decrease the total loading on the line, is charged positively under the VAMM methodology. In brief, the VAMM calculation is determined as follows:

1) The power flow transmission system is modelled

- typical power flow data modelled explicitly as submitted by the transmission owners
- mileage data for all transmission lines modelled
- Generation- Load Pairing Data

2) The Megawatt-mile impacts for each transmission owner are determined for each generation-load pairing by generator unit.

3) Nominations are made for planned resources. Each transmission customer selects its resources governed by ownership and contractual entitlement. The aggregated total actual megawatt capacity nominated from its planned resources by a transmission customer must be at least equal to the greater of (a) 115% of that transmission customer's system firm peak summer demand forecasted for the next future year, or (b) that customer's latest historical system demand calculated.

- for each nomination, there must be a generation-load event calculation
- Megawatt-mile impact is determined by each transmission owner for each nominated generation-load event.

4) Transmission Cost of service (TCOS) and VAMM rates

- transmission cost of service is submitted to and approved by the PUCT is used to determine VAMM rates
- VAMM rates are determined by dividing 30% of the TCOS for a particular transmission owner by the total MW-mile impact on that transmission owners transmission system.

3.5.3.1 Example

Consider a six-bus system composed three generators buses and two load buses. There are two transmission utilities serves the transmission services. The model definition is as follows [25]:

1) Transmission Owner A owns

a. Transmission lines

- Line 3 to 2 (1 mile)
- Line 3 to 6 (3 miles)

b. Generator(s)

- Bus 3

c. Load

- Bus 6

d. Generator Load Event

-100% of generator at bus 3 serves 100% load at bus 6

2) Transmission Owner B owns

a. Transmission lines

- Line 1 to 2 (4 miles)
- Line 1 to 6 (4 miles)
- Line 2 to 5 (2 miles)
- Line 4 to 5 (6 miles)
- Line 4 to 6 (4 miles)

b. Generators (s)

- Bus 1
- Bus 4

c. Load

- Bus 5

d. Generator Load Event

- 100% of generators at buses 1 and 4 serve 100% of load at bus 5 proportionally.

Figure 3.8 shows the transmission generation and consequent megawatt power flow from each generator to the load

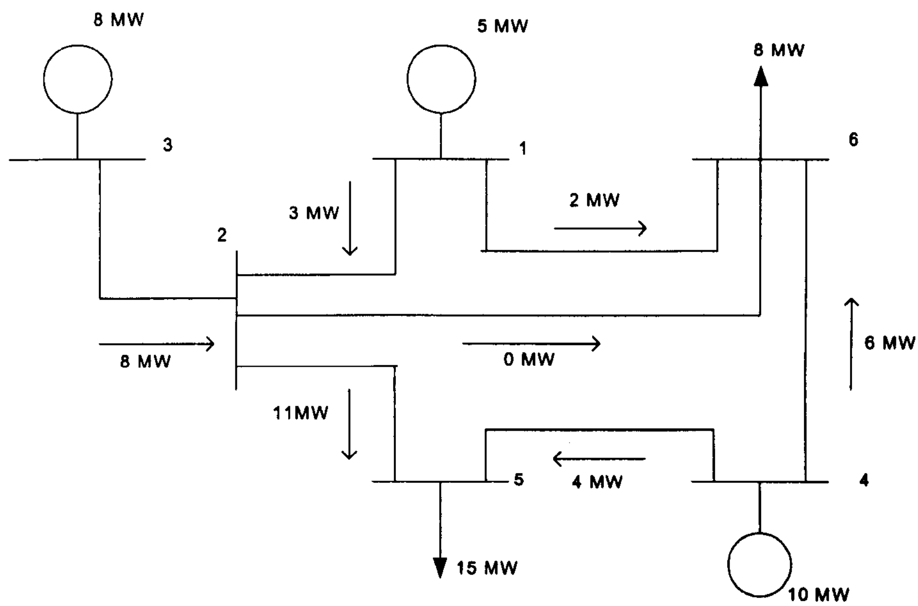

Figure 3.8 Total Power Flow

Figure 3.9 shows the impact of the load at bus 6 being serves by its planned resource, generator at bus 3. The generation at buses 1 and 4, and load at bus 5 have been removed. The impact on the transmission system is strictly due to the 3-6 generation-load event.

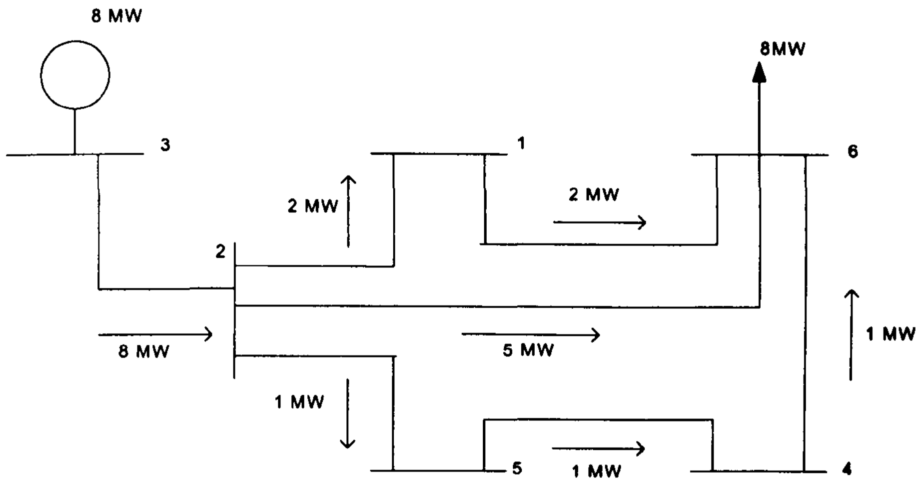

Figure 3.9 Power Flow due to Generator at Bus 3

Using the same method as derived above, the impact of the load at bus 5 being serves by its planned resources; generators at bus 1 and 4 also can be determined. Tables 3.14, 3.15 and 3.16 depict the power flow results for each generator serving its load. These results are used to determine the MW-mile impact to the lines owned by the Transmission Owner A (T_A) and Transmission Owner B (T_B). The MW-mile impact is determined by multiplying the power flow and the length of the respective line. As the calculation is based on VAMM, there is no credit or reward given to the customer due to counterflow.

Table 3.14 Power Flows and MW-mile Caused by Generator at Bus 1

Generator	MW	Line	Miles	MW flow	MWM(T_A)	MWM(T_B)
G1	5	3-2	1	0	0	
		2-6	3	-1	3	
		1-2	4	2		8
		1-6	4	3		12
		2-5	2	3		6
		4-5	6	-2		12
		4-6	4	2		8

Table 3.15 Power Flows and MW-mile Caused by Generator at Bus 3

Generator	MW	Line	Miles	MW flow	MWM(T_A)	MWM(T_B)
G3	8	3-2	1	8	8	
		2-6	3	5	15	
		1-2	4	-2		8
		1-6	4	2		8
		2-5	2	1		2
		4-5	6	-1		6
		4-6	4	1		4

Table 3.16 Power Flows and MW-mile Caused by Generator at Bus 4

Generator	MW	Line	Miles	MW flow	MW-M(T_A)	MW-M(T_B)
G4	10	3-2	1	0	0	
		2-6	3	-4	12	
		1-2	4	3		12
		1-6	4	-3		12
		2-5	2	7		14
		4-5	6	3		18
		4-6	4	7		28

Table 3.17 shows the MW-mile impact for each generator to the transmission system. This impact is determined by taking into account the nomination condition as stated in 3(a) above.

The MW-mile impact is then summed to determine the total MW–mile impact to the transmission system.

Table 3.17 Total MW-miles Impact to Transmission System

Generator	MW	Nomination	MW-M(T_A)	MW-M(T_B)
1	5	5.75	3.450	52.900
3	8	9.20	26.450	32.200
4	10	11.50	13.800	96.600
		Total system use (MW-miles)	43.700	181.700

The total MW-mile impact for both transmission owners is used to determine the VAMM rate, which is based on 30% of the transmission cost of service (TCOS). Consider the TCOS for transmission owners A and B is $5000 and $15000 respectively. Hence, the TCOS need to recover by VAMM is $1500 and $4500. The VAMM rate can be calculated by dividing these values with the total MW-mile impact for the respective transmission system owners.

For Transmission Owner A

$$VAMM_{rate}(T_A) = \frac{\$1500}{43.700MW} = \$34.32 / MW$$

For Transmission Owner B

$$VAMM_{rate}(T_B) = \frac{\$4500}{181.700MW} = \$24.77 / MW$$

The calculated rate is then applied to all generators to calculate the generator's charges. Table 3.18 shows the use of system charges allocated to the generators to recover 30% of annual facility charges for transmission owners A and B.

Table 3.18 Generation Locational Charges Recovered from VAMM

Generator	Transmission Owner A	Transmission Owner B
1	\$118.42	\$1310.13
3	\$907.89	\$797.47
4	\$473.68	\$2392.40
Recovered from VAMM	\$1500	\$4500

The remaining 70% of TCOS, which is not remunerated is recovered using postage stamp method. This method is applied to the generators based on an average rate without taken into account the location of the generators.

3.5.4 SPP, Arkansas USA

Southwest Power Pool, Inc. (SPP) is a regional reliability council of the North American Electric Reliability Council. In 1997, SPP filed its proposed transmission tariff (Regional Tariff) to provide pool-wide, short-term firm and non-firm point-to-point transmission services for periods of less than one year using distance-based pricing. Long-term point-to-point transmission services and network transmission services will continue to be provided by the SPP public utility members through their open access transmission tariffs. The proposed services would replace certain services that the public utility members of SPP had previously provided under their individual open access transmission tariffs. SPP has 18 transmission-owning members and 13 of those members had agreed to participate in the Regional Tariff.

The Regional Tariff provides for a power pool-wide uses the MW-mile method to charge the transmission services. Under this method, each SPP member will compute the average cost of each member's transmission lines and these data are used to compute a pool wide average transmission line cost per MW-mile (i.e., average pool-wide transmission line costs divided by the sum of the MW-mile capacity of all lines). An additional calculation pool-wide transformer costs per MW of transformer capacity is also made. Using the peak impacts of the native loads of all SPP members as a base case, SPP models for each possible receipt and delivery point combination of : (1) the MW-mile impact of the transaction on the SPP system and the MW amount of transformer capacity used; and (2) the relative participation of each SPP member involved in the transaction.

SPP employs the MW-mile absolute value method; that is, a load impact that reduces loadings on a line (a negative impact) is counted the same as a load flow impact that increases loadings on a line (a positive impact). The cost per MW-mile is based on the thermal capability of the transmission facilities rather than on the peak use of the facilities. SPP performs load flow studies twice a year to model each possible transaction, i.e., each possible delivery point and receipt point combination. Based on these data, SPP will compile a matrix that establishes the rates for each possible transaction. The user will pay the rate set forth in the matrix, and revenues will be shared by the SPP members participating in the transaction based on the MW-mile impact of the transaction that affects the SPP members [27].

3.5.4.1 Example

A simple 5 bus system is used to illustrate the absolute value method employed by SPP. The transmission line parameters and costs is shown in Table 3.19 below.

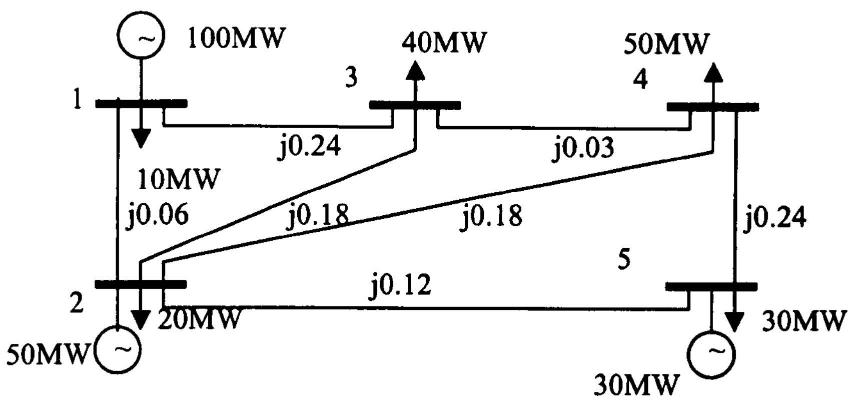

Figure 3.10 A Simple 5 Bus System

There are two transactions to deliver the power which as follows:

T1: Injection of 5 MW at bus 2 and removal at bus 4

T2: Injection of 5 MW at bus 5 and removal at bus 1

Table 3.19 Transmission Lines Parameters and Costs

Bus i	Bus j	Capacity (MW)	Distance (mile)	Transmission Cost (10^3\$)
1	2	100	14.4	200
1	3	100	57.6	900
2	3	100	43.2	550
2	4	100	43.2	550
2	5	100	28.8	300
3	4	100	7.2	100
4	5	100	57.6	900

1) The MW-mile impact for individual branch of transmission lines is determined from the difference between the base case and transaction related flow case. The total MW-mile impact is calculated using absolute value method as shown in Table 3.20 and Table 3.21.

Table 3.20 MW-mile Impact for Transaction T1

Line	Base case power Flow (MW)	T1 case power flow (MW)	MW impact (ΔMW)	MW-mile impact $(\Delta MW - mile)$
1-2	57.0001	54.3215	2.6786	38.5718
1-3	32.9999	33.7141	0.7142	41.1379
2-3	24.9998	26.8450	1.8452	79.7126
2-4	27.9998	30.1109	2.1111	91.1995
2-5	34.0000	33.0873	0.9127	26.2858
3-4	18.0001	19.5954	1.5953	11.4862
4-5	-3.9998	-6.0395	2.0397	117.4867
			$\sum \Delta MW - mile$	405.8805

Table 3.21 MW-mile Impact for Transaction T2

Line	Base case power Flow (MW)	T2 case power flow (MW)	MW impact (ΔMW)	MW-mile impact $(\Delta MW - mile)$
1-2	57.0001	53.0715	3.9286	56.5718
1-3	32.9999	31.9284	1.0715	61.7184
2-3	24.9998	24.8807	0.1191	5.1451
2-4	27.9998	27.6823	0.3175	13.716
2-5	34.0000	30.5079	3.4921	100.5725
3-4	18.0001	16.8096	1.1905	8.5716
4-5	-3.9998	-5.5078	1.508	86.8608
			$\sum \Delta MW - mile$	333.1562

c) The transmission line cost per MW-mile

This cost rate is determined based on the average pool-wide transmission line costs divided by the sum of the MW-mile capacity of all lines. The MW-mile capacity of each line is calculated by multiplying the length of the line in miles by the thermal capacity of the line in MW as shown below

The total transmission line costs ($) = (200 + 900 + 550 + 550 + 300 + 100 + 900) x10^3

$$= \$\ 3500 \times 10^3$$

Total MW-mile capacity = 100 x (14.4 + 57.6 + 43.2 +43.2 +28.8 +7.2 + 57.6)
= 25200 MW-mile

Thus, the transmission line cost per MW-mile = 3500 x 10^3 /25200
= **$138.89/MW-mile**

d) Transmission charges for T1 and T2

The transmission charges for transactions T1 and T2 can be calculated by multiplying the transmission line cost per MW-mile and the total of MW-mile impact of the transactions respectively.

For transaction T1

TC_{T1} = $138.89 / MW-mile x 405.8805 MW-mile
= **$ 56372.74**

For transaction T2

TC_{T2} = $138.89 / MW-mile x 333.1562 MW-mile
= **$ 46272.06**

3.5.5 Discussions

Examples 3.5.1.2, 3.5.2.1, 3.5.3.1 and 3.5.4.1 show the wheeling charge calculation methodology for four transmission utilities. It can be observed that the DC load flow analysis is being used by the transmission utilities to estimate the contribution of the transmission users in the line power flows. Meanwhile, MW-mile/MW-km is used to allocate the transmission cost among the users. Furthermore, it can be seen that, the transmission utilities have something in common i.e. in the usage of the marginal approach to determine the power flow impact in the transmission line. However, there is a difference in the way the total MW-mile/MW-km impact for each transaction is calculated. For instance, in the case of the SPP and ERCOT, this utility uses the absolute approach to calculate the total MW-mile impact while the NGC and the ESBNG use the net approach. The latter approach provides reward to the users for their contribution in the counterflow.

In the context of transmission based charges, it can be observed that the transmission utilities also differ in determining the charge due to the total MW-mile/MW-km impact. In the case of the NGC, the wheeling charge calculation is not straightforward since the pricing methodology is based on the Long Marginal Cost Pricing method. Several factors have to be taken into account such as expansion factor, with its magnitude derived from the projected cost of 400kV overhead line that NGC is expected to incur. On the other hand, for SPP, ESBNG and ERCOT, the charges are based on the existing use of the system cost. However, in the case of the SPP and ESBNG, the charge is based on circuit capacity while the ERCOT is based on the actual capacity used.

Furthermore, for the revenue remuneration methodology, the NGC uses the LRMC methodology based on the forecast target revenue to remunerate the revenue which is not covered by the locational charge. This method seems not to be transparent to the user. Meanwhile the ESBNG and the ERCOT use the Postage Stamp methodology for their remuneration strategy. The method is simple and transparent and is widely used to determine the non-locational charge. However, this thesis limits the work to the locational use of system charges.

3.6 Summary

This chapter discusses the use of system charges methodology in the transmission services. The chapter first gives a brief discussion several components included in the use of system charges. It comprises a system service charge, infrastructure charge, exit charge, entry charge and wheeling charge. The discussion however focuses on the wheeling charges since it is related to the proposed approach. The general idea of allocating percentage of the use of system charges that is currently used and adapted by the transmission utilities in some countries are presented. It can be seen that the transmission utilities have their own justification in allocating these charges to the users. For instance, both Chile and Argentina allocated these charges only to the generators with the belief that the transmission services are required by the generators to reach the consumers. On the other hand, England and Wales allocate the charges to the generators and demands based on the ratio of 27:73. Meanwhile, other countries like Colombia and Brazil use the ratio of 50:50.

In order to have a clear picture of the structure of use of system charges, this chapter focuses the discussion on the UK's use of system charges, which involved three transmission utilities. It can be observed that, there are similarities in the use of system charges structure between the SHETL and SPTL in their levies on infrastructure charges on generation and demand, and system service charge on demand. The key difference is that the SHETL imposes levies on entry and exit to the generators connected to their system. However, these charges are levied to all generators and demands connected to the system. On the hand, the NGC imposes levies on two separate types of charges for use of system. It imposes levies on Transmission Network use of system charges (TNUoS), which cover the long term costs of providing and maintaining transmission assets and Balancing Service use of system (BSUoS) charges, which cover the short-term costs of maintaining a balanced system in real time. The TNUoS charges are levied on entry (generators) and exit (demand) and based on zonal basis. This means that, generators and demands will use the same use of system charges tariff if they are in the same zone.

This chapter also discusses the concept of wheeling taking into account the different types of wheeling, the nature and duration of wheeling. The costs associated with wheeling have been described in some details especially on existing system cost since this cost is related to the use of system charges. This cost which is usually the largest component of the overall of the transaction has raised several issues related to the revenue collected by the utilities. The issues are: to whom the cost of existing transmission system should be allocated and how should the cost of existing transmission system be allocated among the wheeling transactions. For this reason, several use of system measures has been developed to be used by the transmission utility. The simplest and the most popular one is Postage Stamp method, which is based on power demand and the other one, is based on power flow and reflects the actual operation of transmission system i.e. the MW-mile method. The merits and the drawbacks of each method in providing better economic signals to wheeling parties are discussed in details in this chapter. Finally this chapter presents the wheeling charge methodologies currently used by transmission utilities in some countries to determine the charge for the transmission services.

Four transmission utilities; National Grid Company (NGC), United Kingdom, Electricity Supply Board National Grid (ESBNG), Republic Ireland, Electric Reliability Council of Texas Interconnection System (ERCOT), Texas, USA and Southwest Power Pool, Arkansas, USA have been selected to investigate their similarities and their implementation. It can be observed that, a similarity among the transmission utilities is the use of DC load flow to estimate the contribution of the transmission users in line power flows, the use of marginal approach to determine the power flow change in the transmission lines and the use of MW-mile/MW-km to allocate the transmission costs. However, there are some differences in the approach used to reflect the total MW-mile impact. The difference occurs because some transmission utility, e.g. ESBNG considers the reward or credit for the transmission users due to their contribution in counterflow. It also can be observed that the transmission utilities differ in determining their wheeling charge. For instance, in the case of the ESBNG and SPP, the wheeling charge is determined based on the circuit capacity while the ERCOT is based on the total actual capacity used. However both charges are levied to the users based on individual transaction. On the other hand, in the case of NGC, the charge is based on the projected cost of 400kV overhead line that NGC is expected to incur and the charge is levied to the users based on zonal basis. The users in the same zone would pay the same charge.

In the context of revenue remuneration, the ERCOT and ESBNG have employed the Postage Stamp method to determine their remuneration charge, however, the proportion charges which are remunerated by this method differed among the utilities. On the other hand, the NGC uses the LRMC methodology for revenue remuneration which is based on the forecasted revenue recovery target.

In conclusion, this chapter gives an experience view of the role of the use of system charges in transmission services. These charges have been used by the transmission utilities as a main element to recover the cost of existing transmission system. There are two separate elements in these charges namely; locational use of system charges and non- locational use of system charges and the transmission utilities have several alternative methods to determine these two charge elements. However, it can be observed in this chapter that the MW-mile/MW-km methodology is being used by the transmission utilities to determine the locational use of system charges while the Postage stamp method can be considered among the commonest method used by the transmission utilities to determine the non-locational use of system charges. In the context of locational use of system charges, it can be observed that the marginal approach is being used by transmission utilities to determine the power flow impact in the transmission lines. Although this approach can determine the amount of power flow caused by a particular transaction, but it may fail to recognise that a transaction may basically reduce the flow of the line.

Other aspect which can also be observed in this context, is the approach that has been used to calculate the total MW-mile impact of the transaction. The ERCOT and SPP use the absolute approach to calculate the total MW-mile impact while the ESBNG and NGC use the net approach. In both cases, either transmission utility or the transmission users would receive the benefit from the counter flow. Based on these two aspects which have been discussed above, this thesis aims to improve these two approaches with the development of a new approach which is based on profit sharing approach. This approach will be defined and formulated in Chapter 4.

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CHAPTER 4

METHODOLOGY AND MATHEMATICAL MODEL OF THE PROPOSED APPROACH FOR WHEELING CHARGES

4.1 Introduction

This chapter describes the methodology and the mathematical model of the proposed approach for the use of system charges; wheeling charges. This chapter will first discuss the shortcomings of the existing wheeling charges methodology currently used in the transmission utilities. The results from the analysis of four transmission utilities are used as a base for the development of the proposed approach. This chapter then presents and formulates the MW-mile methodology as it is related to the proposed approach and discusses the positive and negative aspects using alternative MW-mile approaches to wheeling charges. Finally this chapter will discuss the methodology and the mathematical model of the proposed approach together with the incorporated approaches. An example and flow chart will be used to describe the significant of the proposed approach in providing a better wheeling charge allocation scheme.

4.2 Reasons of Development of the Proposed Approach

In Chapter 2 and Chapter 3, the issues associated with the cost of transmission services and wheeling charges were discussed in detail. The issues concerns the way the cost of transmission services is satisfactorily allocated among all the involved participants, taking into account as accurately as possible the real impact of every transaction on the transmission system. With these issues, several strategies for pricing the use of transmission services have been proposed in order to provide adequate economic signal to the transmission users as well as transmission utilities.

However, there are some aspects related to the transmission services which can be improved especially in the issues of allocation method, pricing the counterflow user and revenue reconciliation as explained in Chapter 2. For example, in the issue of allocation method, it can be seen that the distribution factors has been used widely by the transmission utilities to identify the contributions of the transmission users to the line flows. However, these factors still have some weaknesses since they are relying on some conditions. For instance, the GSDF is depending on the selection of the reference bus, i.e. different reference bus gives different factors [8]. This could cause some difficulties in the system if the transmission users are allowed to choose their own reference bus to accommodate the transaction (e.g. NGC DCLF transport model). On the other hand, the GGDF and the GLDF are independent of reference bus, and instead they are depending on the operating conditions. Other related issue is concerning with the counterflow users. This issue is still being debated i.e. on what basis should the credit or reward be given to the transmission user who reduces the total net flow of the transmission system. Although some alternative methods have been developed and used so far such as the zero counter pricing and others which are based on the MW-mile methodology, but many transmission utilities felt uncomfortable with the idea of providing a service and in addition paying the users for using it. The reason is clear because by giving the credit to the transmission users for their contribution in counter flow could cause difficulties to the transmission utilities to recover the revenue requirement. However, it can be seen that some transmission utilities (e.g. the ESBNG and NGC) have accepted and applied this idea in their wheeling charges calculation. The only difference among them is the method that they are using to cover the revenue which is not remunerated. The question that may rise here is, how far the latter method can treat the users in a fair manner?

Finally, the issue of revenue reconciliation as explained in section 2.8 is still considered as unsolved issue since the present methods developed for this purpose still have some weaknesses. For example, a method based on the Ramsey Pricing has disadvantage of penalising least flexible transmission users more than others, thereby introducing differential treatment during revenue reconciliation, which may not be acceptable to the users in general [5]. Furthermore, there is also other method proposed in [9] to overcome the pricing problem in the Ramsey Pricing method. This proposed method, which is based on the use of system, modified the cost per MW-mile used in the calculation until the revenue requirement is met. The adjusted cost per MW-mile is then applied uniformly across all the branches. In this manner, the proposed method claimed that the user is treated uniformly for the revenue reconciliation. Although this modification giving flexibility in the revenue recovery process but its application is restricted to the MW-mile approach which is not taking into account the effect of the counterflow.

Having looked at some problems hindering the smooth wheeling charge calculation, it is clear that research is needed to improve the weaknesses of the existing wheeling charge scheme focussing on the three main issues addressed above. The methodology and mathematical model of the proposed wheeling charge approach derived in this Chapter which is based on the MW-mile methodology and will look into the benefits of the both transmission utilities and the users in the use of transmission system.

4.3 Concept and Formulation of MW-mile (MW-km) Methodology

MW-mile methodology is a technique for ascribing the use of the electric power transmission system among the various beneficiaries. It may be regarded as the first pricing strategy proposed for the recovery of fixed transmission costs based on the actual use of transmission network [1-3]. Many economists prefer this concept because it encourages the efficient use of the transmission facility and the expansion of the system. The development of this method is explained in [4] which can be expressed mathematically as;

$$WC_t = A_i.\sum_i C_i.\frac{\sum_i l_i \Delta P_{i,t}}{\sum_i l_i \overline{P_{i,t}}} \qquad (4.1)$$

where i = indicates transmission lines

A_i = annual fixed charge rate in per-unit or percent

C_i = annual embedded cost of transmission line in £

l = length in mile

ΔP = change or impact in line flow due to transaction t in MW

$\overline{P}$ = transmission line (circuit) capacity in MW

ΔP can be either positive or negative flow impacts. Negative ΔP occurs when the lines loading decreases due to wheeling transaction while positive ΔP occurs when the lines loading increases. Depending upon the sign of ΔP, three cases can be distinguished:

a) absolute impact : the absolute value of positive and negative ΔP are added.

$$\sum_i |\Delta P_i| \qquad (4.2)$$

b) only positive impact : only positive value of ΔP are added.

$$\sum_i +\Delta P_i \qquad (4.3)$$

c) net impact: the negative value of ΔP are subtracted from positive value of ΔP.

$$\sum_i \pm \Delta P_i \qquad (4.4)$$

A variation of this method is obtained by referring the costs of the changes due to the wheeling transaction to the sum of absolute power flows in the transmission lines as shown in equation (4.5).

$$WC_t = A_i.\sum_i C_i.\frac{\sum_i l_i \Delta P_{i,t}}{\sum_i l_i |P_{i,t}|} \qquad (4.5)$$

Depending on of the sign of ΔP, three cases also can be distinguished as in equations (4.2), (4.3) and (4.4) above to determine the wheeling charges based on sum of absolute power flows. In our proposed approach in this thesis, the negative value of ΔP is shared between the transmission owner and users to reconcile the transmission owner's revenue as well as an incentive to the users.

4.3.1 Positive and Negative Aspects of MW-mile Methodology

As mentioned earlier, the MW-mile methodology is widely used to recover the embedded transmission costs. This method is used to overcome the marginal cost pricing which is not effective in pricing the transmission service due to the revenue reconciliation (recovering the total transmission cost) problems. However, economically speaking, this method does not encourage the optimal usage of the transmission assets nor does it send 'true' economic cost messages to the users [5]. It also continues to suffer from the defects of a failure to distinguish between the relative importance of different lines to the secure operation of the system as a whole and to the reliability of each transmission transaction [6].

As shown in equations (4.1) and (4.5), this method offers two alternative methods that can be used to calculate the wheeling charge that is; MW-mile based on the circuit capacity and MW-mile based on sum of absolute power flows.

The MW-mile method based on the circuit capacity is charging the transmission users based on the percentage utilisation of the circuit capacity, that is, the transmission users will be charged only for the actual capacity used but not for the unscheduled capacity. The drawbacks of this method are:

a) This formulation cannot get full recovery of the fixed transmission costs since the total flows are usually smaller than the circuit capacities under normal system conditions
b) The total ignorance of the reliability value of transmission margin under system contingency conditions

On the other hand the MW-mile method based on the sum of absolute power flows caused by all transmission users was introduced to ensure the full recovery of all the embedded costs and assumes, inherently, that all transmission users have to pay both for the actual capacity used and for the unused transmission capacity. This unused payment may be due to the need to meet reliability, stability and security criteria or due to system adjustments. However, this method also has some drawbacks:

a) The pricing rule does not encourage more efficient use of transmission systems because no matter how the line capacity is utilised, the total costs will be recovered.
b) The cost allocation procedure seems to be unfair to some users in the sense that they have to share the cost of an expensive transmission facility for which only a small portion of the facility capacity has been utilised. On the other hand, adequate transmission margin is required to maintain system reliability
c) The users who participate latter in the transaction will pay less since the total actual capacity used is close to the circuit capacity (i.e. when the transacted power increases).

There are three different MW-mile approaches that can be used to determine the user charges for a particular transaction, and they are classified as net, absolute and positive only approaches as depicted in equations (4.2), (4.3) and (4.4). The MW-mile net approach subtracted any negative flow (counterflow) from the positive flow change before the wheeling charge calculation takes place. This approach assumes that any negative flow which alleviates the line load could result in loss reduction and the delay in the transmission investment to increase the transmission capacity.

However, the transmission owner would probably receive an inappropriate revenue return if the transaction coincidently creates many negative flows across the transmission network. Meanwhile, in the case of the MW-mile positive only approach, any negative flow created during the transaction will not be included in the wheeling charge calculation. Since the wheeling charge calculation is based on the positive flow, the transmission owner still has the opportunity to receive the revenue although it may not be enough to recover the transmission cost. On the other hand, the MW-mile absolute approach does not give any credit to any transaction that alleviates the transmission load as a result of a negative flow. The wheeling charge is determined by summing the absolute value of negative flow and positive flow change during the transaction. Although this approach promises sufficient revenue to the transmission owner but it has a few flaws. Firstly, it overcharges the counterflow users by ignoring the reduction in the system net flows that they produce. Secondly, it increases the market power by making it more expensive for generators to compete for more distant customers, thereby limits the competition. The drawbacks of the aforementioned approaches can be improved if the benefit from the counterflow is shared between the transmission owner and the users. The proposed approach, which will be formulated in the following section, attempts to overcome these disadvantages.

4.4 Mathematical Model for the Proposed Approach

This section describes the concept and formulation of the proposed approach to allocate the wheeling charges among the users of the transmission services. It also includes the description of the allocation method *(JDF)* used to estimate the contributions of the transmission users in the line flows and it also describes the incremental absolute approach used to calculate the MW-mile impact in the transmission lines. These two elements are incorporated into the proposed approach. The flow chart that describes the proposed approach, which is based on Matlab^{TM} programming is shown in Figure 4.3.

4.4.1 Justified Distribution Factor

The generalised shift distribution factors (GSDF or A factors) shown in equation (2.3) is a factor that can estimate the changes in the line flows with the change in power injection in a bus. As explained in Section 2.6.1, the distribution factors are traditionally used to evaluate the contingencies and system security. However, in the new environment, it is used to estimate the power flow distribution over several lines to evaluate FTRs and also to determine the resource effectiveness in relieving a congestion. These factors are obtained from a DC linear power flow approximations. For instance, the A's factor for line *i-j* for an injection at bus *i* with respect to the reference bus *m* can be calculated as follows:

$$A^{m}{}_{i-j,i} = \frac{X_{ii} - X_{ji}}{X_{ij}} \qquad (4.6)$$

where

$A_{i-j,i}$	A factor used to determine the power flow at line *i-j* due to injection power at bus i.
X_{ii}, X_{ji}	elements of the reactance matrix without reference bus column and row.
X_{ij}	the reactance of line between buses *i* and *j*

Using the same equation above, the A's factor for every line with different bus injection can be obtained. For instance, A's distribution factors with respect to the reference bus m (m=1) can be written in a general *n*th row and *m*th column matrix form as follows:

$$A^{m=1} = \begin{bmatrix} 0 & A_{12} & . & . & A_{1m} \\ . & A_{22} & . & . & A_{2m} \\ . & . & . & . & . \\ . & . & . & . & . \\ 0 & A_{n2} & . & . & A_{nm} \end{bmatrix} \tag{4.7}$$

Meanwhile, A's distribution factors with respect to the reference bus n (n=2) can be written as

$$A^{n=2} = \begin{bmatrix} A_{11} & 0 & . & . & A_{1m} \\ . & 0 & . & . & A_{2m} \\ . & . & . & . & . \\ . & . & . & . & . \\ A_{n1} & 0 & . & . & A_{nm} \end{bmatrix} \tag{4.8}$$

From equations (4.7) and (4.8), it can be observed that the set of distribution factors for a pair of nodes found using a particular reference bus differs from the one using another bus. This could cause more time used to generate new set of distribution factors if the users request to use different reference node to accommodate their transaction (e.g. NGC DCLF Transport Model). Furthermore, it would also be unsuitable to use it in the transmission pricing or congestion management since the participants could not predict the prices and avoid congesting the network with ease, if they do not know what the reference is [7]. The distribution factor that varies according to the reference bus however, has successfully been implemented independent of the references bus by making use of the properties of the distribution factors as derived in [7]. The developed distribution factor, which is called the Justified Distribution factor (*JDF*) is formed by adding a justification factor J_{ij}^{m} to the original A_{ij}^{m} so that the distribution factors for line *i-j* at bus *i* and bus *j* have the same magnitudes but with opposite sign, where mathematically,

$$J_{ij}^{m} = -\frac{A_{ij}^{m}(i) + A_{ij}^{m}(j)}{2} \qquad (4.9)$$

$$JDF_{ij}^{m} = A_{ij}^{m} + J_{ij}^{m}\{1\} \qquad (4.10)$$

where $\{1\}$ = a vector with all elements equal to 1

Using the same method as shown in the equations (4.9) and (4.10), a vector containing justified distribution factor for the other lines can also be calculated. Hence, the *JDF* with respect to the reference bus *m* can be written in a *n*th row and *m*th column matrix as follows;

$$JDF^{m} = \begin{bmatrix} JDF_{11} & JDF_{12} & . & . & JDF_{1m} \\ JDF_{21} & JDF_{22} & . & . & JDF_{2m} \\ . & . & . & . & . \\ . & . & . & . & . \\ JDF_{n1} & JDF_{n2} & . & . & JDF_{nm} \end{bmatrix} \qquad (4.11)$$

Arithmetic shows that

$$JDF_{ij}^{m}(i) = JDF_{ij}^{n}(i) \qquad (4.12)$$

The power flow in line $i-j$ can be calculated using equation (4.13)

$$P_{ij} = \sum_{i}^{n} JDF_{ij}^{i}.P_{i} \qquad (4.13)$$

The *JDF* is originally used to solve the congestion curtailment in the bilateral trading [7]. In this thesis, the *JDF* is used to estimate the contribution of the user in the line flows and at the same time to identify the counterflow lines. The result generated from the *JDF*, will be used to calculate the wheeling charge that should be shared due to the counterflow. The advantage of the *JDF* over the A's distribution factors is; the element in the distribution matrix does not vary with the reference bus position is shown in Appendix B.

4.4.2 Incremental Absolute Approach

It can be observed that, the marginal approach is a common approach used by the transmission utilities to determine the power flow impact in the lines as depicted in Section 3.5. In the proposed approach, the net power flow impact for each line is determined by the incremental absolute approach, which considers the difference in magnitude irrespective of the direction of flow. This approach will give the actual value of power flow impact in the lines as shown in equation (4.14).

$$\Delta P_{i-j} = \left|\pm P_{t,i-j}\right| - \left|\pm P_{b,i-j}\right| \qquad (4.14)$$

where ΔP_{i-j} = power flow impact in line $i-j$

$P_{t,i-j}$ = power flow in line $i-j$ during transaction in MW

$P_{b,i-j}$ = power flow in line $i-j$ for base case in MW

ΔP is negative power flow impact if $\left|\pm P_t\right| < \left|\pm P_b\right|$

In most cases these two approaches will give exactly the same result. The exception is illustrated in Figure 4.1.

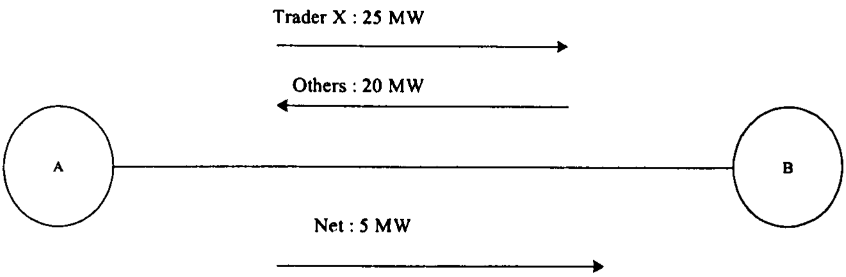

Figure 4.1 The Low Flow Situation

The marginal approach would charge trader X for 25MW-miles by assuming A and B is one mile distance (Marginal calculation: 5-(-20)=25), while the incremental approach would reward trader X for 15 MW-miles of flow (Incremental calculation: 5-20= -15). It can be seen that marginal approach failed to recognise that the trader has basically reduced the flow on the line. Table 3.8 in Chapter 3 shows such an example whereby the transmission owner failed to recognise that line 1-2 should be rewarded. Another problem is that, it provides a very strong incentive for trader X to reduce the flow to 19MW at which point the flow suddenly becomes a counterflow and is given a MW-mile credit. The effort done for this re-dispatch to get MW-mile incentives could cause inefficiencies on the generation side. In conclusion, the incremental absolute approach seems slightly preferable because it may cause, on average, a little less distortion of the dispatch.

4.4.3 Negative Flow Sharing Approach

Counter flow or negative flow is the flow component contributed by a particular transaction that goes in the opposite direction of the net flow. It can either alleviates the line load with the same direction of the net flow or alleviates the line load but opposite direction of the net flow. The ESBNG, Republic of Ireland and the NGC, UK use the latter definition to include the counterflow impact in the wheeling charges while the ERCOT of Texas remains with the original MW-mile formulation where the impact of the transaction on the flows is measured by the magnitude so that all transmission users are required to pay for the use of the lines irrespective of the flow direction. On the other hand, the CIS of Chile does not include the counter flow in the wheeling charges since they assumes that it is beneficial for the system as a whole to free transmission capacity. However, there could be a lot of problems if the counter flow is not charging at all, like for instance: how can one define up to what point a flow is considered to be countered or reversed, considered the non-linearities involved? What could be the immediate impacts on the system if the reversed transaction is suddenly removed from the system [8]? These issues should be defined clearly by the transmission utilities or the regulators.

Meanwhile, as mentioned in Section 2.7.6 in Chapter 2, the proposals of giving credit to the users producing counter flows may not be easily accepted by the transmission utilities. However, the methods, which do not take into account the effect of counter flow, are against the new trend towards competition. In this thesis, the transmission owner and the users will share the benefits of the counter flow using profit sharing approach. The concept and formulation of the proposed approach can be explained as follows:

Firstly, determine the power flow impact in all the lines of the transmission system when a new wheeling transaction is taking place in the system by using equation (4.14). After that, the power flow impact calculated in all the lines is summed using the proposed approach. This proposed approach uses the same method as the existing MW-mile approaches to sum any positive power flow impact in the lines. The total positive power flow impact for n lines can be written as

$$\sum_{i}^{n} \Delta P_i = \Delta P_{pos} \qquad \text{for all } \Delta P_i > 0 \qquad (4.15)$$

However, there is some modification in the summation of the negative power flow impact incurred in the lines. This total impact, which was formerly a negative value, is taken as absolute value and then by using the profit sharing factor, r, the share proportion of this value for transmission utility can be calculated. For n lines it can be written as

$$\frac{1}{r}\sum_{i}^{n}\left|\Delta P_i\right| = \frac{\Delta P_{neg}}{r} \quad \text{for all } \Delta P_i < 0 \qquad (4.16)$$

Based on the combination of equations (4.15) and (4.16), the new total power flow impact equation can be obtained as shown in equation (4.17)

$$\Delta P_{ps} = \Delta P_{pos} + \frac{\Delta P_{neg}}{r} \qquad (4.17)$$

To illustrate how the wheeling charge can be determined with the proposed approach, we consider a single line circuit as shown in Figure 4.2.

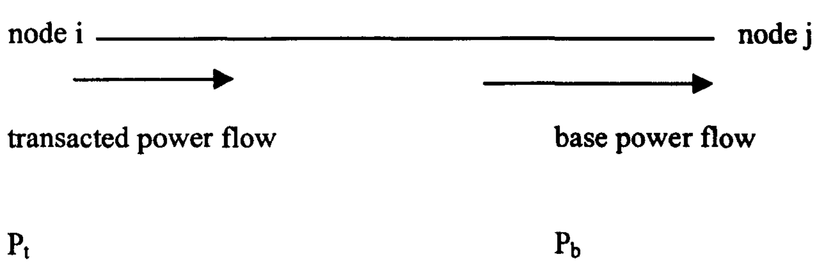

Figure 4.2 Single Line Circuit

Let WC_{i-j} be the charge for line *i-j*, which can be written as;

$$WC_{i-j} = A_{i-j}\frac{C_{i-j}}{\overline{P_{i-j}}}.\Delta P_{i-j} \qquad (4.18)$$

where

A_{i-j} = fixed charge rate for line *i-j* in per-unit

C_{i-j} = embedded cost of line *i-j* in £

$\overline{P_{i-j}}$ = circuit capacity in MW

$\Delta P_{i-j} = P_t - P_b$

= power flow impact either positive flow or negative flow

For simplicity, we assume A_{i-j}, C_{i-j}, and $\overline{\dot{P}_{i-j}}$ are equal 1 pu thus

$$WC_{i-j} = \Delta P_{i-j} \tag{4.19}$$

Using equation (4.2) the wheeling charge based on absolute approach can be written as;

$$WC_{i-j} = \Delta P_{i-j} \text{ for } \Delta P_{i-j} > 0 \tag{4.20}$$

$$WC_{i-j} = \Delta P_{i-j} \text{ for } \Delta P_{i-j} < 0 \tag{4.21}$$

Using equation (4.3) the wheeling charge based on positive only approach can be written as;

$$WC_{i-j} = \Delta P_{i-j} \text{ for } \Delta P_{i-j} > 0 \tag{4.22}$$

$$WC_{i-j} = 0 \qquad \text{for } \Delta P_{i-j} < 0 \tag{4.23}$$

While from equation (4.4) the wheeling charge based on net approach can be written as;

$$WC_{i-j} = \Delta P_{i-j} \text{ for } \Delta P_{i-j} > 0 \tag{4.24}$$

$$WC_{i-j} = -\Delta P_{i-j} \text{ for } \Delta P_{i-j} < 0 \tag{4.25}$$

The wheeling charge resulted from equation (4.21) shows that there is no benefit given to the transmission user for their contribution in counter flow. On the other hand, the wheeling charge resulted from (4.23) shows that the transmission service seems to be provided as free to the user since no charge is being collected from the transaction. Meanwhile, the wheeling charge resulted from equation (4.25) can caused the transmission owner to pay the service that they provided to the transmission users, which is not acceptable.

In the proposed approach, the drawbacks of the existing approaches dealing with counterflow transaction can be improved if the benefit of the charge due to this transaction is shared between the user and the owner of the transmission system. This can be done by distributing the proportion of wheeling charge found when $\Delta P_{i-j} < 0$ by using the profit sharing factor, r.

Therefore, the equations (4.21), (4.23) and (4.25) is replaced by the new developed wheeling charge equation and can be written as

$$WC_{i-j} = \frac{|\Delta P_{i-j}|}{r} = \frac{WC_{i-j,neg}}{r} \quad \text{for } \Delta P_{i-j} < 0 \qquad (4.26)$$

where r = the factor used to determine sharing of the profit between the transmission owner and users due to the negative power flow or counterflow

While from equations (4.20), (4.22) and (4.24) the wheeling charge for positive power flow can be rewritten as

$$WC_{i-j} = \Delta P_{i-j} = WC_{i-j,pos} \quad \text{for } \Delta P_{i-j} > 0 \qquad (4.27)$$

For n lines, the proposed wheeling charge equation can be written as;

$$WC_{ps} = \sum_{i}^{n} WC_{ipos} + \frac{1}{r}\sum_{i}^{n} WC_{i\,neg} \qquad (4.28)$$

or

$$WC_{ps} = WC_{pos} + \frac{WC_{neg}}{r} \qquad (4.29)$$

In the case of simultaneous transaction, the proposed approach allocates the negative charges as an incentive to the transmission users according to the proportion of their contribution in counterflow. This proportion can be obtained by evaluating the sensitivity of the power flow on the lines with respect to each transaction in two different cases. Firstly, when the associated transaction is introduced in the base case system and secondly, when it has been removed from the simultaneous transaction case system. It can be noticed that the lines which involved in the counterflow and the amount of negative MW impact produced for both cases for IEEE 14 bus system are the same as shown in Tables C.1, C.2 and C.3 in Appendix C.

Based on this observation, the proportion of incentive charge for each transaction can be calculated as follows:

$$WIC_{Ti} = \frac{\Delta P_{neg,Ti}}{\sum_{i}^{k} \Delta P_{neg,Ti}} \cdot \frac{WC_{neg}}{r} \qquad (4.30)$$

where;

WIC_{Ti}	=	wheeling incentive charges for transaction user *i*.
$\Delta P_{neg,Ti}$	=	negative power flow impact produced by transaction user *i*
k	=	number of simultaneous transaction users.

The wheeling charge for transaction user i can be calculated by considering the following equation:

$$WC_{abs} = WC_{ps} + WIC \qquad (4.31)$$

where;

WC_{abs} = wheeling charge based on absolute approach

WC_{ps} = wheeling charge based on proposed approach

WIC = incentive charges rewarded to simultaneous users

Rearrange equation (4.31), yields

$$WC_{ps} = WC_{abs} - WIC \qquad (4.32)$$

Based on the equation (4.32), the wheeling charge for transaction user i with respect to the k simultaneous transaction users can be calculated.

$$WC_{ps\,Ti} = \frac{WC_{abs}}{k} - WIC_{Ti} \qquad (4.33)$$

The sharing factor r in the equation (4.29) is determined according to the willingness of transmission owner to share the profit with transmission users. For example, if this factor is set to 2, the transmission owner and the transmission user will receive 50% of the benefit of the counterflow respectively. Meanwhile, if the factor is set to 5, the transmission owner will receive 20% of the benefit of the counterflow and the remaining 80% is rewarded to the transmission user. Furthermore, the sharing factor can also be set based on the defined transmission user. Table 4.1 shows the proposed profit sharing factor, r set according to the transmission defined user.

Table 4.1 The Profit Sharing Factor According to the Transmission Defined User

	Profit sharing factor, *r*	Transmission defined user
1.	2	Generator
2.	3	Generator and Demand
3.	4	Generator, Demand and Out-of- merit Generator

It can be observed that, in the case of transmission defined user is the generator only; the profit sharing factor r can be set to 2 so that the transmission owner and user will share equally the benefit from the counterflow. Meanwhile, for transmission-defined user, which includes the generator and demand, it could be set to 3. In this case, one-third of the charge due to the counterflow is added into the basic wheeling charge while the other two-third of the charges are rewarded to the generator and demand. Furthermore, the profit sharing factor could further be set to 4, which in this case the transmission owner receives 25% of the profit due to the counterflow and the other 75% is rewarded to the transmission users.

The existence of the sharing factor r in the above equations behaves as an incentive factor to the transmission user. Depending on the value of r that is set by the transmission owner, the transmission users would receive the proportion of negative charge for their contribution in enhancing transmission capacity. Meanwhile, at the same time it also behaves as a security or compensatory factor to the transmission owner as they will also receive back the proportion of the negative charge. This could avert the situation that the transmission owner receiving lower return revenue when they are involved in the counterflow transaction. Unlike the existing MW-mile approaches, the proposed approach treats the negative charge which formerly is a credited charge to the transmission users for their contribution to counter flow as a 'balancing charge' to both transmission owner and users. The reason that the users who create the counter flow should share the proportion of this charge is self obvious because they manage to decrease the flow on the lines, and in this way they could increase the remainder of the line available transfer capacity. On the other hand, the transmission owner should also share the proportion of the charge because they provide the transmission facilities. The flow chart in Figure 4.3 below allocates the proposed approach. As mentioned earlier, this proposed approach incorporated with *JDF* and incremental absolute approach to form a better wheeling charge allocation scheme.

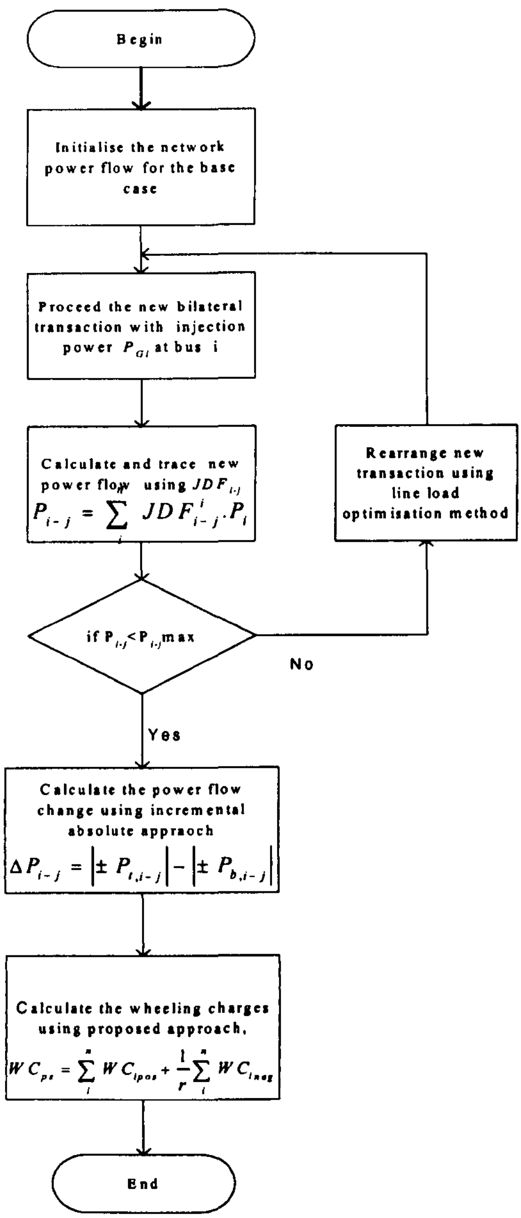

Figure 4.3 Proposed Wheeling Charge Allocation Scheme

4.4.4 Example

Consider the three nodes network in Figure B.1 in Appendix B. The power 1 MW is injected from node 3 and removed at node1. The wheeling charge rate is £15.216/MW-mile which is taken as an example from NGC data and the profit sharing factor r is varied from 2-4.

i) Calculate the power flow for each line of the network for base case and transacted flow case using *JDF* in equation (4.13).

Base case

$$P_{12} = 0.25(500-100) + (-0.25)(650-50) + (0)(0-1000) = -50 \text{ MW}$$

$$P_{13} = 0.375(500-100) + (-0.125)(650-50) + (-0.375)(0-1000) = 450 \text{ MW}$$

$$P_{23} = (-0.125)(500-100) + (0.375)(650-50) + (-0.375)(0-1000) = 550 \text{ MW}$$

Transacted flow case

$$P_{12} = 0.25(500-101) + (-0.25)(650-50) + (0)(1-1000) = -50.25 \text{ MW}$$

$$P_{13} = 0.375(500-101) + (-0.125)(650-50) + (-0.375)(1-1000) = 449.25 \text{ MW}$$

$$P_{23} = (-0.125)(500-100) + (0.375)(650-50) + (-0.375)(1-1000) = 549.25\text{MW}$$

ii) Calculate the power flow impact using equation (4.14)

$$\Delta P_{12} = |-50.25| - |-50| = 0.25$$

$$\Delta P_{13} = |449.25| - |450| = -0.75$$

$$\Delta P_{23} = |549.25| - |550| = -0.75$$

iii) Calculate the MW-mile impact for every line by multiplying the power flow impact found in ii) with the line distance respectively.

$$\Delta MW - mile_{12} = 0.25 \times 3.75 = 0.9375$$

$$\Delta MW - mile_{13} = -0.75 \times 6.25 = -4.6875$$

$$\Delta MW - mile_{23} = -0.75 \times 16.25 = -12.1875$$

iv) Calculate the wheeling charge using equation (4.27). It can be observed that the line 1-2 has resulted positive MW-mile impact while line 1-3 and line 2-3 result negative MW-mile impacts. According to the proposed approach, the MW-mile impacts of lines 1-3 and 2-3 should be shared between the transmission owner and the user. Therefore, the wheeling charge can be calculated as follows:

For r = 2

$$WC_{ps} = £15.216 \times \left(0.9375 + \frac{1}{2}\left(|-4.6875| + |-12.1875|\right)\right) = £142.65$$

For r = 3

$$WC_{ps} = £15.216 \times \left(0.9375 + \frac{1}{3}\left(|-4.6875| + |-12.1875|\right)\right) = £99.86$$

For r = 4

$$WC_{ps} = £15.216 \times \left(0.9375 + \frac{1}{4}\left(|-4.6875| + |-12.1875|\right)\right) = £78.46$$

4.5 Summary

This chapter presents the methodology and the mathematical model of the proposed approach for wheeling charges. This chapter first identified problems that could be faced by some transmission utilities during the determination of wheeling charges which are focussed on three main issues; allocation method, counterflow user and revenue reconciliation. In the case of allocation method, it can be observed that the distribution factors are commonly used by the transmission utilities to estimate the contribution of the users in lines flows. However, this factor relies on some conditions. For example, the GSDF is depending on the selection of reference bus, i.e. different reference bus gives different factors. This could cause some difficulties in the system if reference node varies according to the user's request (e.g. NGC DCLF transport model). Meanwhile, the counterflow user and revenue reconciliation is also other important issues discussed in this chapter. The idea of rewarding the users for their contribution in counterflow is still being debated although some transmission utilities have already adopted this concept in their wheeling charges calculation. The main reason that many transmission utilities are reluctant to accept this idea is because the revenue collected might not be sufficient to recover the transmission cost. Although other method such as Postage Stamp can be used by the transmission utility (e.g. ESBNG) to reconcile the revenue that is not covered by the earlier method, but the question is, does this method treat users in a fair manner. In the case of revenue reconciliation, the proposed methods developed still have limitation in its implementation as addressed in the earlier section in this chapter.

Based on the findings above, a proposed approach for wheeling charges is developed to tackle such problems. The proposed approach is developed based on the modification of the existing MW-mile methodology taking into consideration the economic benefits of both trading parties through analysing their shares in negative power flow or counterflow. This proposed approach is incorporated with the *JDF* and an incremental absolute approach to form a better wheeling charge allocation scheme. The use of the JDF enables the transmission utilities to estimate the contribution of the users in the line power flows and at the same time identifying the counterflow lines. It also has the capability to deal with the different reference bus users. Meanwhile, the reason of using the incremental absolute approach is to give the actual value of power flow impact in lines.

In conclusion, this chapter presents an original contribution to determine the use of system charges; wheeling charges. With a new wheeling charge allocation scheme developed in this chapter, the problem arising on the issue of the allocation method, counterflow users and revenue reconciliation of transmission services can be solved.

The significant of the new wheeling charge alloaction scheme can be observed through several case studies which will presented in the next chapter.

4.6 References

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CHAPTER 5

WHEELING CHARGES ANALYSIS: MATLAB SIMULATION RESULTS

5.1 Introduction

This chapter presents the simulation results of wheeling charges based on the proposed approach developed in Chapter 4. The proposed approach is tested for different transaction arrangements and locations in order to evaluate its capability to provide sufficient return revenue to the transmission owner as well as a fair charge to the transmission user.

5.2 Case Studies

The proposed approach has been tested on four bus systems; the 5 bus system, 9 bus system, IEEE-14 bus system and the 6 bus system. In the 5 bus system, the transmission network is owned by a single transmission utility. The capability of the proposed approach in generating the wheeling charges for single transaction was investigated. Meanwhile, in the 9 bus system, the proposed approach was tested to multiple transactions which involved two transmission utilities. In this case study, further investigation was carried out on the capability of the proposed approach in providing fair transmission revenue to the transmission utilities. On the other hand, in the IEEE-14 bus system, the proposed approach was tested to allocate the wheeling charges for simultaneous transaction. Finally, in the 6 bus system, the proposed approach was tested on its capability in providing appropriate return revenue in the pool based trading. These case studies are based on dc power flow and neglecting losses. The wheeling transaction is firm transmission transaction and involves only real power and the contributions of reactive power flows are neglected. We assume the generators have to pay 100% of the transmission cost of services to the transmission owner. The profit sharing factor r used to determine the share in negative power flow in Case Studies 2, 3 and 4 is set to 2 (equally shared). On the other hand, for Case Study 1, the profit sharing factor, r is first set to be 2 and then varies accordingly in order to see its impact to the wheeling charges. The *JDF's* distribution factors for the 5 bus, 9bus and the IEEE-14 bus systems that are used to estimate the contribution of the transmission users in the line flow are shown in Appendix D.

5.3 Results of 5 bus system

In this case study, the proposed approach is tested on the 5 bus system as shown in Figure 5.1. The transmission data and the transmission cost of services used for the test system are referred in [1]. The base case of generation and load data systems based on designated data is given in Table E.1 of Appendix E.

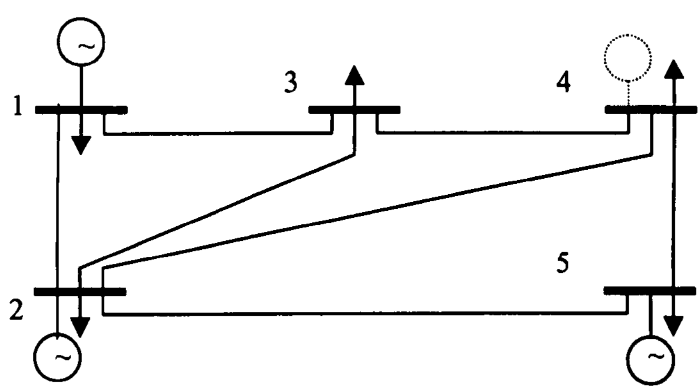

Figure 5.1 Wheeling Transaction in 5 Bus System

There are two wheeling transactions involve in the bilateral trading which is as follows:

T1: Injection of 5 MW at bus 1 and removal at bus 5

T2: Injection of 5 MW at bus 4 and removal at bus 2

Table 5.1 Base Case Flows and Transaction Related Flows for T1 and T2

Line	*Base case power Flow (MW)*	*T1 case power flow (MW)*	*T2 case power flow (MW)*
1-2	57.0001	60.9287	54.3215
1-3	32.9999	34.0713	33.7141
2-3	24.9998	25.1188	26.8450
2-4	27.9998	28.3173	30.1109
2-5	34.0000	37.4921	33.0873
3-4	18.0001	19.1906	19.5954
4-5	-3.9998	-2.4919	-6.0395

Table 5.1 depicts the transaction related flows for T1 and T2. It can be seen that the transaction T1 causes power flow increases in most of the lines as a result of the positive flow transaction. On the contrary, transaction T2 causes the power flow decreases in most of the lines due to the counter flow transaction. The wheeling charge can be obtained by first determining the total power flow impact, ΔP_i for related transactions using equation (4.2), (4.3), (4.4) and (4.17) respectively. Table 5.2 summarises the total power flow impact resulted from different approaches.

Table 5.2 Total Power Flow Impact in MW-mile

Transactions	*absolute*	*net*	*positive only*	*proposed*
T1	333.14	159.43	246.29	289.71
T2	296.23	-271.54	12.34	154.28

It can be noticed that the values of total power flow impact for T1 for the different approaches are close to each other because of the effect of positive flow transaction. However, big differences are clearly observed in the case of T2 since it associates with counter flow transaction. As the wheeling charge is directly proportional to the power flow impact, the transmission owner could loss some revenue in this transaction. This situation only occurs as in the case of net and positive only approaches because the benefits of the counter flow are credited solely to the transmission users. However, through the profit sharing concept introduced in the proposed approach, the transmission owner's revenue can be improved as observed in Table 5.3.

Table 5.3 Wheeling Charges (£) Based on Different Approaches

Transactions	*absolute*	*net*	*positive only*	*proposed*
T1	43822	20971	32396	38109
T2	38966	-35718	1624	20295

Furthermore, as explained in Section 4.4.3 of Chapter 4, the profit sharing factor, r in the proposed approach varies according to the willingness of the transmission utility to share the profit due to the negative power flow. Therefore, there is several possibility of the amount of wheeling charge that can be collected from the transmission user due to the variation of profit sharing factor, r as depicted in Figure 5.2. It can be observed that the wheeling charge recovery decreases with the increase of the value of profit sharing factor, r.

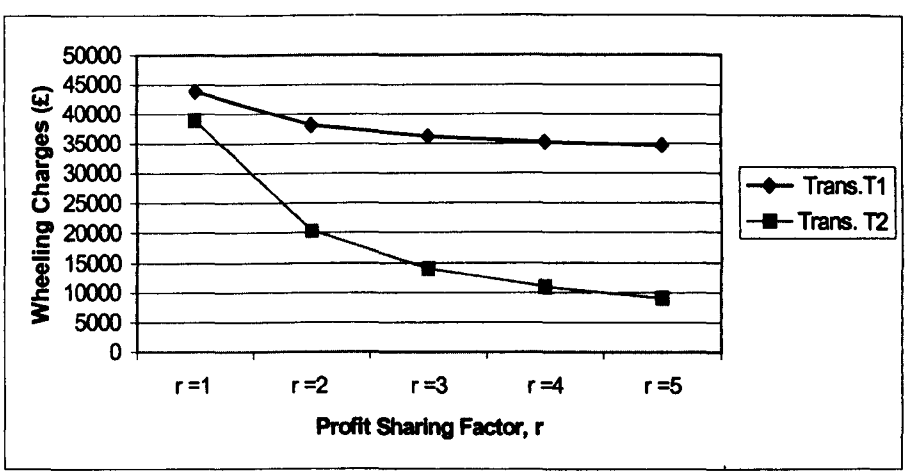

Figure 5.2 Wheeling Charges Recovery with the Variation of Profit Sharing Factor, r

However the revenue return for transmission owner for these two transactions is still better compared to the one found from the net and positive only approaches. Figure 5.3 depicts the revenue return of transmission owner with the variation of profit sharing factor, r.

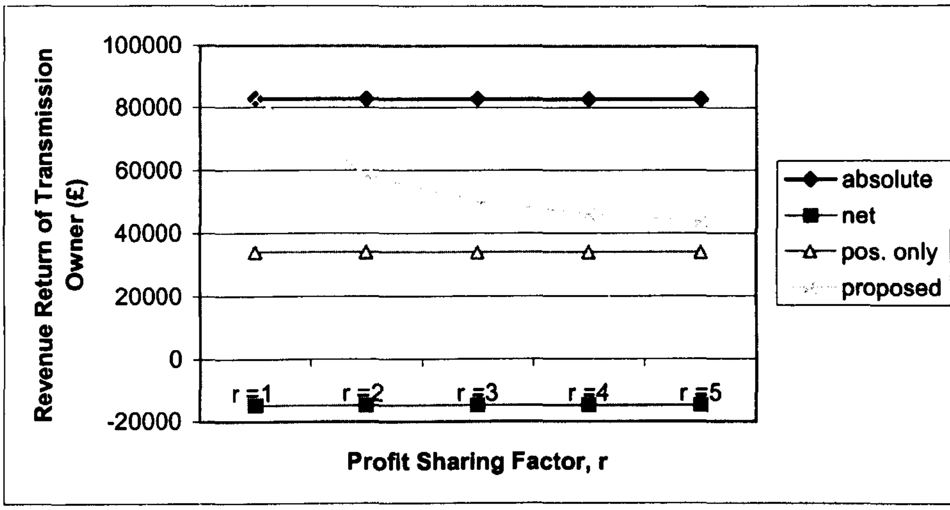

Figure 5.3 Revenue Return of Transmission Owner with the Variation of Profit Sharing Factor, r

5.4 Results of 9 bus system

The 9 bus system shown in Figure 5.4 is used as a test system for evaluating the charges associated with three wheeling transactions. There are two transmission owners involved in the transactions. Transmission Owner A owns transmission lines; 1-4, 4-5, 5-6. Transmission Owner B owns transmission lines; 3-6, 6-7, 7-8, 8-2, 8-9 and 9-4. The wheeling charges rate (£/MW-Mile) is based on circuit capacity.

The base case of generation and load data based on designated data is given in Table E.2 in Appendix E while the transmission lines parameters and costs are given in Table F.1 in Appendix F.

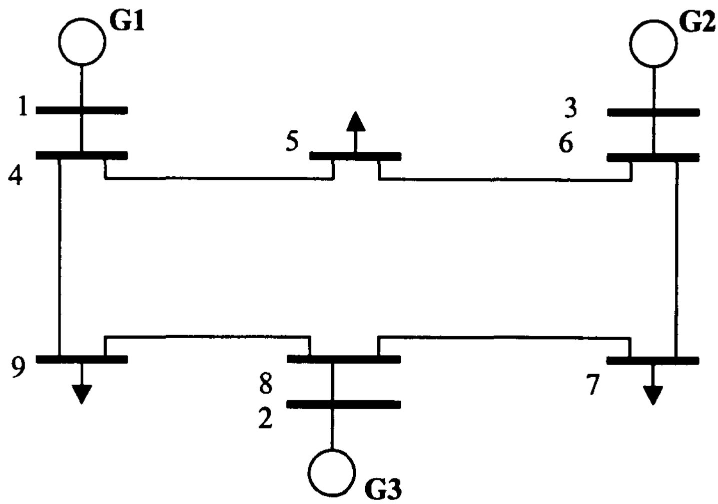

Figure 5.4 Wheeling Transaction in 9 Bus System

The details of the transactions are as follows [2]:

Transaction T1 : Injection of 50MW at bus 2 and removal at bus 6

Transaction T2 : Injection of 50MW at bus 3 and removal at bus 5

Transaction T3 : Injection of 50MW at bus 3 and removal at bus 7

Table 5.4 Base Case flows and Transaction Related Flows for T1, T2 and T3

Line	*Base case power flow (MW)*	*T1 case power flow (MW)*	*T2 case power flow (MW)*	*T3 case power flow (MW)*
1-4	67.0007	67.0007	67.0007	67.0007
4-5	28.9678	41.6589	41.4531	21.5467
5-6	-61.0323	-48.3414	-98.5467	-68.4353
3-6	85.0002	85.0002	135.0004	135.0004
6-7	23.9673	-13.3418	36.4526	66.5644
7-8	-76.0327	-113.3417	-63.5475	-83.4358
8-2	-163.0000	-213.0000	-163.0000	-163.0000
8-9	86.9670	99.6579	99.4522	79.5639
9-4	-38.0328	-25.3418	-25.5475	-45.4359

Table 5.4 depicts the transaction related flows for transactions T1, T2 and T3 respectively. It can be seen that these three transactions caused power flow to increase in most of the lines as a result of the positive flow transaction. However, the amount of wheeling charge paid for the transmission owners is depending on the sum of the MW-mile impact in their lines and the approach used.

Table 5.5 Wheeling Charges (£) for Two Transmission Owners

	absolute		*net*		*positive only*		*proposed*	
	T_A	T_B	T_A	T_B	T_A	T_B	T_A	T_B
T1	15921	47029	-4846	26830	5538	36930	10730	41980
T2	36142	38206	36142	19786	36142	28996	36142	33601
T3	9288	44850	2827	33648	6057	39249	7672	42050

N.B. T_A and T_B are transmission owners

Table 5.5 shows the wheeling charges calculated for the two transmission owners. It can be observed that the wheeling charges vary according to the transaction locations and the calculation approach used. For instance, the transmission owner TA has received less revenue for transaction T3 compared to the transaction T2 although both transaction cases used the same wheeling charges calculation approach. This scenario occurs due to the difference of the amount of MW-mile impact produced as a result of transaction location. Furthermore, it can also be observed that there are significant differences on the revenue collected among the transmission owners when the wheeling charge calculation approach is taken into account.

Figure 5.5 depicts the wheeling charges calculated for transmission owners TA and TB based on transaction T1. It can be seen that the wheeling charges obtained from the MW-mile net approach is lower and could even be negative when the transaction creates a more negative flow in the lines instead of a positive flow. Meanwhile, for the MW-mile positive only approach, the transmission owners still received some revenue as long as there is positive power flow created in the lines. On the other hand, the MW-mile absolute approach provides appropriate revenue to both transmission owners, since it ignores the counterflow effects. With the proposed approach, it averts the transmission owners from losing the revenue collected due to the negative charge i.e. TA and at the same times improved the wheeling charge which is formerly based on the MW-mile net approach and MW-mile positive only approach i.e. TB.

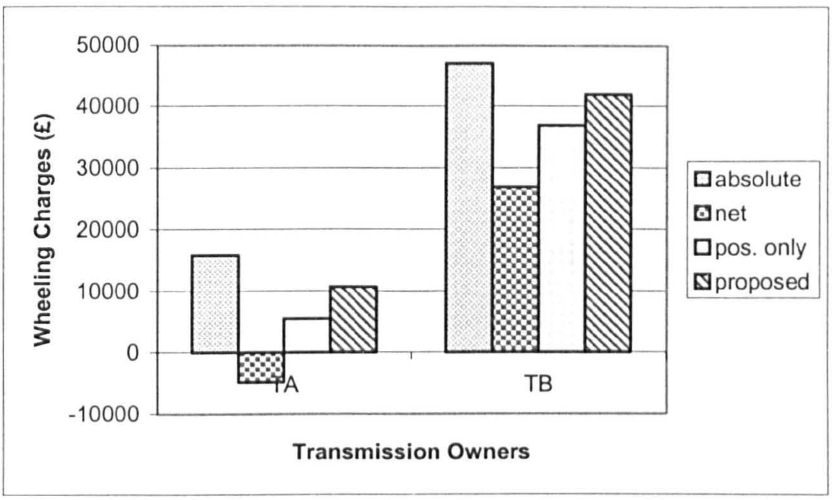

Figure 5.5 Wheeling Charges for Transaction T1

5.5 Results of IEEE 14 bus system

In this case study, the proposed approach is tested to IEEE 14 bus system as shown in Figure 5.6. Altogether, three wheeling transactions have been considered, which involved different transaction locations and arrangements. These locations can be categorised as close, distant and counter flow. In the analysis the transactions are considered first separately and then simultaneously. The details of the transactions are as follows:

T1: Injection of 20MW at bus 1 and removal at bus 5

T2: Injection of 20MW at bus 2 and removal at bus 14

T3: Injection of 20MW at bus 3 and removal at bus 1

T1+T2+T3: Simultaneous transactions with T1, T2 and T3

The base case of generation and load data for both systems based on designated data is given in Table E.3 of Appendix E. The transmission data and the transmission cost of services used for the test system are referred in [1] with some modification. The wheeling charge is calculated in two ways: based on the network capacity and the sum of the absolute actual power flow respectively.

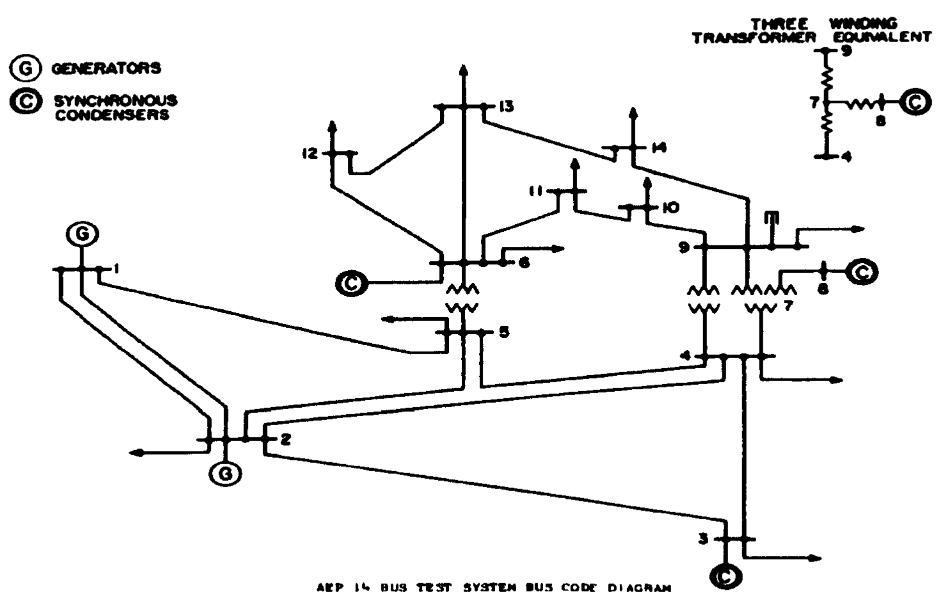

Figure 5.6 Wheeling Transactions in IEEE 14-Bus System

Table 5.6 Transaction Related flows and Base Case flows for three non-Simultaneous Bilateral Transactions for IEEE-14 bus system.

Line	Capacity	Base Case	T1	T2	T3
1-2	200	147.8164	160.0268	143.9188	132.8872
1-5	100	71.1486	78.9361	75.0421	66.0794
2-3	100	70.0100	72.0716	73.1727	59.3700
2-4	100	55.1424	59.4569	61.7613	52.2752
2-5	100	40.9623	46.7974	47.2839	39.5411
3-4	100	-24.1897	-22.1281	-21.0270	-14.8297
4-5	100	-61.7437	-55.7189	-63.3587	-55.6105
4-7	100	28.3506	28.5724	35.5472	28.5777
4-9	100	16.5459	16.6754	20.7460	16.6784
5-6	100	42.7685	42.4150	51.3678	42.4105
6-11	100	6.7177	6.5049	7.3716	6.5020
6-12	100	7.6068	7.5756	9.3734	7.571
6-13	100	17.2492	17.1401	23.4287	17.1383
7-8	100	0.000	0.000	0.0000	0.0000
7-9	100	28.3510	28.5728	35.5477	28.5781
9-10	100	5.7576	5.9690	5.1010	5.9744
9-14	100	9.6414	9.7816	21.6950	9.7842
10-11	100	-3.2315	-3.0195	-3.8869	-3.0152
12-13	100	1.5067	1.4755	3.2732	1.4750
13-14	100	5.2586	5.1184	13.2049	5.1158

Table 5.6 shows the power flow pattern for IEEE-14 bus system for the base case and also the transaction related flows. It can be observed that the power flows at all lines differ among the transactions because they are influenced by the transaction arrangements and locations. However none of them exceeds the network capacity.

Table 5.7 Wheeling Charges (£) Based on Network Capacity

Approach / *Transaction*	*absolute*	*net*	*positive only*	*Proposed*
T1	52927.98	37115.80	45021.89	48974.94
T2	177676.54	162284.17	169980.35	173828.45
T3	66807.75	-63089.55	1859.10	34333.42

Table 5.7 shows the wheeling charges determined based on network capacity. In this charging method, the transmission users will be charged only for the actual capacity used but not for the unused capacity. It can be seen that the wheeling charges for transaction T1 and transaction T2 are very similar among the approaches since they are positive flow transaction. However, for the transaction T3, the wheeling charges

obtained are different since they are associated with counter flow transaction. It is clearly observed that the transmission owner either receives low return or is under negative charge when the contribution of counter flows is taken into account. As a result, it seems difficult for the transmission owners to recover the transmission costs.

Conversely, the wheeling charge based on total sum of the absolute actual power flows as shown in Table 5.8 is higher compared to the one that is based on network capacity. This charging method assumes, inherently that all transmission users have to pay both for the actual capacity used and for unused transmission capacity. These unused charges may be due to the need of system reliability, stability and security criteria.

Table 5.8 Wheeling Charges (£) based on Sum of the Absolute Actual Power Flows

Approach / *Transaction*	*absolute*	*net*	*positive only*	proposed
T1	203421.98	142649.87	173035.93	188228.95
T2	605529.19	553071.33	579300.26	582414.72
T3	286015.33	-270097.09	7959.12	146987.23

This method could help the transmission owner to receive sufficient revenue and thus ensures the full recovery of transmission costs. However, once again the amount of revenue received depends upon the approach used. In the case of counter flow transaction the transmission owner could loss more revenue due to the increase of negative charges. Meanwhile, with the proposed approach, which has been applied for both cases, these losses can be minimised. Figure 5.7 shows the total wheeling charges obtained as a results of the three single wheeling transactions, which are based on network capacity and actual power flow. It can be observed that the revenue increases slightly with the use of proposed approach compared to the other two approaches. This is advantageous since it helps the transmission owner towards revenue reconciliation. Furthermore, as the approach also considers the benefit of the users, there is a significant reduction in wheeling charges as compared with the one that is determined by the absolute approach. Thus, it is a good alternative to replace the absolute approach, which totally ignores the contribution of the transmission user made in the counter flow.

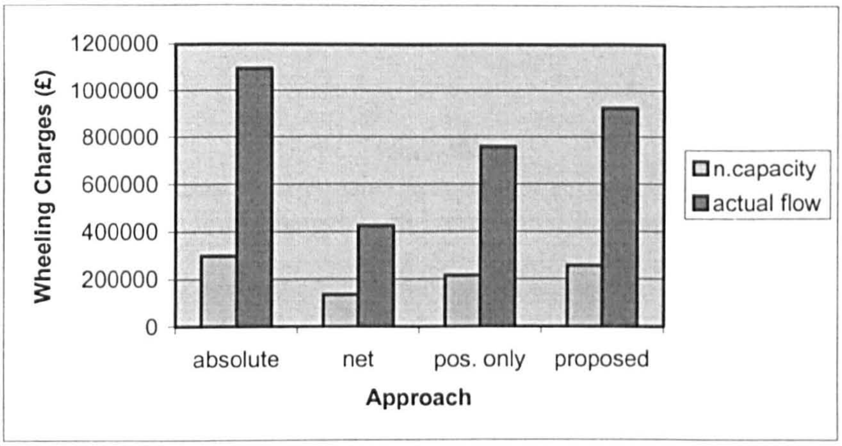

Figure 5.7 Total Wheeling Charges Based on Network Capacity and Sum of the Absolute Actual Power Flows

The proposed approach has also been tested with the incremental power at the transaction locations. Transaction T3 has been chosen to show the capability of the proposed approach in providing appropriate revenue although associated with counter flow transaction. Figure 5.8 shows the variation of wheeling charge with respect to incremental power. It can be seen that the wheeling charge determines using the absolute approach increase positively as it does not consider the counter flow. On the other hand, the charge either increases slowly or decreases negatively when it is determined using positive only approach and net approach respectively.

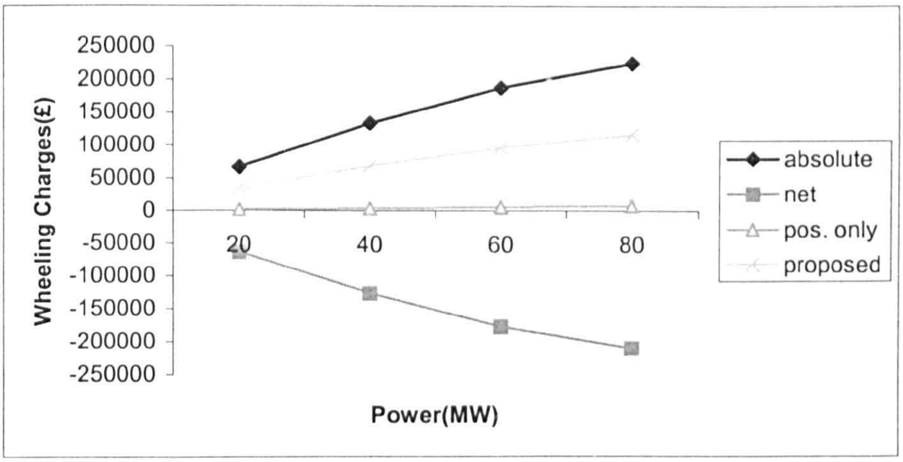

Figure 5.8 Wheeling Charges with Incremental Power for Transaction T3

Meanwhile, it can be observed that the wheeling charge determined by the proposed approach increased positively through the existence of profit sharing factor, *r*. This advantageous over the other approaches could encourage the transmission owner to continue providing services for future transaction without considering the amount of power demand and its location.

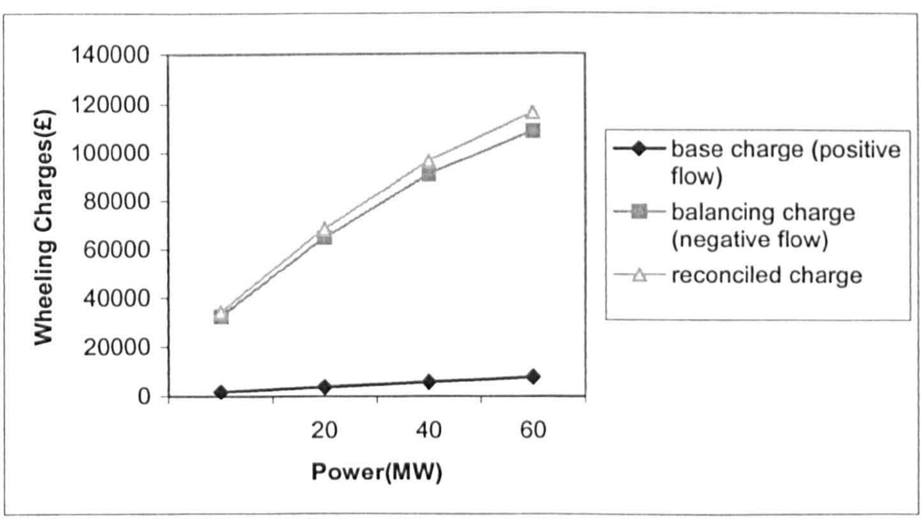

Figure 5.9 Revenue Reconciliation for Transaction T3 Based on Proposed Approach

Figure 5.9 shows the revenue reconciliation for transaction T3 based on the proposed approach. It can be seen that the 'balancing charge' (negative charge) introduced significantly reconciles the transmission owner's revenue. As the benefits of both parties are considered in this approach, the transmission users would also receive incentive from 'balancing charge' for their contribution in counter flow as power demand increases. Figure 5.10 shows the total wheeling charges determined using existing approaches and the proposed approach as the power demand increases for transaction T3. As expected, the proposed approach generates appropriate revenue for transmission owner.

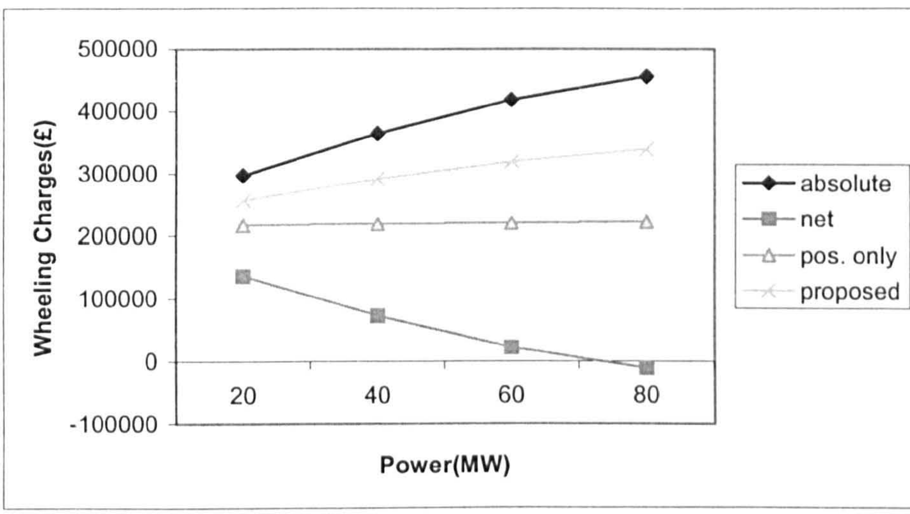

Figure 5.10 Total Wheeling Charges with Incremental Power at Transaction T3

The proposed approach is further tested on simultaneous transaction. In this transaction we consider the power is injected at different injected points simultaneously. Again, the wheeling charge determined by the proposed approach is much better compared to the other two approaches when the counter flow effect is taken into account as depicted in Table 5.9.

Table 5.9 Wheeling Charges (£) for Simultaneous Transaction.

Approach *Transactions*	*absolute*	*net*	*Positive only*	*proposed*
T1+T2+T3	218600	136310	177450	198030

Meanwhile, since this transaction is a simultaneous transaction, the 'balancing charges' that is allocated as an incentive for the transmission users should be distributed according to the proportion of their contribution in counter flow. As explained in Section 4.4.3, this proportion can be obtained by evaluating the sensitivity of the power flow on the transmission lines with respect to each transaction based on two different cases. Table B.1, Table B.2 and Table B.3 in Appendix B depict the power flow sensitivity for transactions T1, T2 and T3. It can be observed that the lines that involved in the counterflow and the amount of negative power flow impact produced for both cases are the same.

The transaction T1 has resulted in the reduction of line flows in 9 lines of the transmission system while the reduction for T2 and T3 are 3 lines and 14 lines respectively. Having these figures, the proportion of the 'balancing charge' for each participant in the simultaneous transaction can be determined. Table 5.10 shows the proportion of 'balancing charge' distributed to the users due to their contribution in counter flow. It can be observed that the wheeling charge for transaction T3 is lower than the other two transactions as a result of its contribution in counter flow.

Table 5.10 Proportion of User's 'Balancing Charge' due to their Contribution in Counter Flow

	T1	*T2*	*T3*
Negative MW-mile impact	84.96	82.7	697.94
Balancing Charge (£)	2019.96	1966.23	16593.81
Wheeling Charge (£)	70850.04	70903.77	56276.19

5.6 Results of 6 bus system

This case study is based on the 6 bus system in Section 3.5.2.1 in Chapter 3. The wheeling charge obtained from the proposed approach is compared with the other charges from the SPP, ESBNG and ERCOT. There are three transactions which involved three generator at buses 1, 2 and 5 to serve a total demand of 100 MW at buses 3, 4 and 6 respectively as shown in Figure 3.6.

Table 5.11 Network Powers Flows when the Generators at Bus 1, 2 and 5 are Removed from the Network Respectively

Circuit	*Total network flows (MW)*	*Generator 1 (MW)*	*Generator 2 (MW)*	*Generator 5 (MW)*
1-2	-3.2099	-10.3045	4.7737	-0.8889
1-3	23.2099	10.3045	15.2263	20.8889
2-3	14.8148	15.4568	2.8395	11.3333
2-4	15.0617	13.0700	3.4979	13.5556
2-6	16.9136	11.1687	-1.5638	24.2222
3-4	8.0247	1.7613	3.0658	11.2222
4-5	-16.9136	-17.1687	-13.4362	-3.2222
5-6	13.0864	12.8313	16.5638	-3.2222

Table 5.11 shows the network power flows when the generators at bus 1, 2 and 5 are removed from the network respectively. The wheeling charge obtained from these transactions is depending on the approach that is used by the transmission utilities to compute the MW impacts of each transaction. As explained in the Chapter 3, the ESBNG adopted a net value approach whereby the generator who is responsible for increasing the flow has to pay the charge while those reducing the flow of the circuit receives the credit. On the other hand, the SPP and ERCOT use an absolute value approach whereby no credit is given to those reducing the flow. Table 5.12 depicts the total MW-mile impacts based on the SPP, ESBNG, ERCOT and proposed approach.

Table 5.12 Total MW-mile Impacts

	SPP	*ESBNG*	*ERCOT*	*Proposed*
G1	35.1523	19.1687	35.1523	31.1564
G2	69.8971	62.9424	69.8971	57.8292
G5	50.1358	29.1235	50.1358	38.4383

It can be observed that the total MW-mile impacts obtained from SPP and ERCOT are more than the ESBNG and proposed approaches since they are not considering the contribution of counterflow lines. Meanwhile, as far as the effects of counterflow is concerned, the total MW-mile generated by the proposed approach is better compared to the ESBNG approach except in the case when the generator 2 is removed from the network. As explained in Section 4.4.2, this situation occurred because the approach used by the ESBNG i.e. marginal approach failed to recognise the actual amount of MW impact to be credited to the user. For example, in the case of generator G2 is removed from the network, the ESBNG calculates the MW impact for line 1-2 (Marginal calculation: -3.2099-4.7737= -7.9836) and considered this value as positive flow since it has the same direction with the total power flow.

Meanwhile, the proposed approach calculates the MW impacts (Incremental Absolute calculation: |-3.2099| -|4.7737|= - 1.5638) and credited this value to the user for reducing the flow of the line. It can be seen that the incremental absolute approach used incorporated with the proposed approach successfully recognised the line that actually involved in the counterflow compared to the marginal approach used by the ESBNG. Figure 5.11 shows the transmission revenue based on different approach.

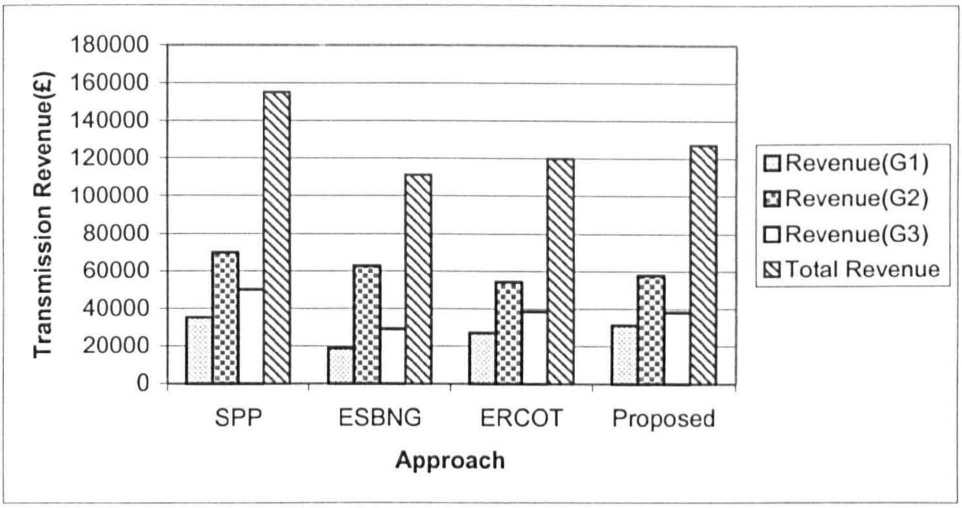

Figure 5.11 Transmission Revenue Based on Different Approach

It can be noticed that the total transmission revenue obtained for the proposed approach is not only more than the one obtained from ESBNG but also from the ERCOT although the approach used by the ERCOT is based on the sum of the absolute actual power flows and at the same time ignores the contribution of the user in the counterflow. This finding result could be a significance factor for the proposed approach to replace the approach used by the ERCOT and SPP which is contended by some of the transmission users i.e. SPP.

5.7 Summary

This chapter presented the simulation results of wheeling charges based on the proposed approach developed in Chapter 4. The proposed approach has been tested for different transaction arrangements and locations in order to evaluate its capability to provide sufficient return revenue to the transmission owner as well as a fair charge to the transmission user. Three case studies which involved with three bus systems; the 5 bus system, 9 bus system, the IEEE-14 bus system and the 6 bus system have been used in this context. These case studies are based on dc power flow and neglecting losses. The wheeling transaction is firm transmission transaction and involved only real power and the contributions of reactive power flows are neglected.

It is assumed that the generators have to pay 100% of the transmission cost to the transmission owner. The profit sharing factor r used to determine the share in negative power flow is assumed as equally shared.
In case study 1, the capability of the proposed approach in generating the wheeling charges for one transmission owner is investigated. There are two wheeling transactions involved in the bilateral trading which can be considered as positive flow transaction and counterflow transaction. It can be observed that the profit sharing factor r introduced in the proposed approach has significant role to balance up the transmission owner's revenue. In the case of positive transaction, its existence increases the revenue collected while in the counterflow transaction, it averts the transmission owner from losing the revenue as a result of negative charges.

Meanwhile, in case study 2, the proposed approach has been tested to 9 bus system to evaluate its capability to provide a fair revenue to two transmission owners. Three transactions are involved in the bilateral trading. Again, it can be seen that the wheeling charges obtained from the proposed approach are fair to both transmission owners compared with the net and the positive approaches. The existence of the profit sharing factor r balanced up the wheeling charges reduced due to the counterflow lines and at the same time ensures the return revenue is reasonable for both transmission owners e.g. transaction T1.

As for case study 3, the proposed approach has been tested to the IEEE-14 bus system to evaluate its capability in dealing with different transaction locations and arrangements. The wheeling charge is calculated in two ways; based on the network capacity and the sum of the absolute actual power flows. Regardless of the transmission locations, it can be observed that the proposed approach has provided a good return revenue to the transmission owner either it is calculated based on the network capacity or the sum of the absolute actual power flows. Furthermore, a new formulation developed for simultaneous transaction which distributes the proportion of 'balancing charge' to the users due to their contribution in counter flow could be used practically to allocates the wheeling charges in a fair manner.

Finally, in the case study 4, the proposed approach has been compared with the approaches adopted by the SPP, ESBNG and the ERCOT. It can be observed that the use of an incremental absolute approach which is incorporated into the proposed approach successfully in recognising the counterflow lines in the network. Unlike the marginal approach used by the ESBNG, SPP and the ERCOT [3], this approach determines the MW impact by considering the difference in magnitude irrespective of the direction of the flow. The credit that given to the transmission user for the counterflow lines is based on the amount of the line capacity reduced from the existing one. As a result the return revenue obtained from the proposed approach reflects to the actual capacity used of transmission network.

In conclusion, the proposed approach introduced in this chapter successfully overcomes the shortcomings of existing MW-mile approaches in the context of revenue reconciliation of transmission services regardless of transaction arrangements and locations. The introduction of a profit sharing factor *r* in the proposed approach provides an intuitive way in allocating the charge for the counter flow lines, which could benefit both parties in the trading. Furthermore, the use of this approach could encourage the generators to be built at the place that can create counter flow and this could mitigate the congested state of transmission lines. As a result, the transmission owner could delay further investment for upgrading transmission capacity.

5.8 References

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CHAPTER 6

CONCLUSIONS AND FUTURE WORK

6.1 Conclusions

This thesis has presented a new wheeling charge allocation scheme for wheeling transaction charges among users in transmission services. This new scheme consists of three components; the proposed approach which is known as the negative flow sharing approach, Justified Distribution Factor and Incremental Absolute Approach. Through the combination of these three components, the problem arising on the issue of the allocation method, counterflow users and revenue reconciliation of transmission services can be solved.

Chapter 2 of the thesis provides a useful framework to analyse the transmission services issues. This framework which can be divided into three important steps; define transmission services, identify transmission costs and calculate transmission costs can be used by the transmission owner to generate an appropriate amount of revenue of the related services. This chapter then highlighted some aspects related to how the transmission services can be improved especially in the issues of allocation method, pricing the user that created counter flow and revenue reconciliation.

Chapter 3 of the thesis gives a review of the role of the use of system charges in the transmission services. These charges are being used by the transmission utilities as a main element to recover the cost of existing transmission system. There are two separate elements in these charges namely; locational use of system charges and non-locational use of system charges and the transmission utilities have several alternative methods to determine these two charge elements. However, it can be observed that the MW-mile methodology is being widely used by the transmission utilities to determine the locational use of system charges while the Postage stamp method can be considered among the commonest method used by transmission utilities to determine the non-locational use of system charges. In the context of locational use of system charges, it can be observed that the marginal approach is being used by transmission utilities to determine the power flow impact in the transmission lines. Although this approach can determine the amount of power flow caused by a particular transaction, but it may fail to recognise that a transaction may basically reduce the flow of the line.

Other aspect which can also be observed in this context, is the approach that has been used to calculate the total MW-mile impact of the transaction. The transmission utilities either use the absolute approach or the net approach to calculate the total MW-mile impact. In both cases, either the transmission utility or the transmission users could receive the benefit from the counter flow. With all aspects mentioned above, a review of wheeling charge methodology supplemented by work examples of the transmission utilities in the U.K, Republic of Ireland and the USA are presented at the end this chapter. Based on the issues discussed in these two chapters, Chapter 4 of the thesis formulates an algorithm for the proposed approach to determine the use of system charges; wheeling charges. The proposed approach which is based on the profit sharing concept taking into consideration the economic benefits of both trading parties through analysing their shares in negative power flow or counter flow. This proposed approach is incorporated with the Justified Distribution Factor and an Incremental Absolute Approach to form a new wheeling charge allocation scheme. The use of the JDF enables the transmission utilities to estimate the contribution of the users in the line power flows and at the same time identifying the counterflow lines. It also has the capability to deal with the different reference buses. Meanwhile, the reason of introducing an incremental absolute approach is to determine the actual value of power flow impact on the lines. Using this approach, the charge or the reward for the user is determined based on the magnitude of power flow that increases or decreases from the base case respectively. With this new scheme, the aforementioned issues that arises in the wheeling charge allocation can be solved.

The significant of the proposed approach over the existing MW-mile approaches can be observed through four case studies which are presented in Chapter 5 of the thesis. It can be observed from the case studies results that the proposed approach in the new wheeling charge scheme can be effectively used to allocate the charge for single transaction and multiple simultaneously transactions.

As overall conclusion, the proposed approach developed in the thesis successfully overcomes the shortcomings of existing MW-mile approaches in the context of revenue reconciliation of transmission services regardless of transaction arrangements and locations. The introduction of a profit sharing factor r in the proposed approach provides an intuitive way in allocating the charge for the counter flow lines, which could benefit both parties in the trading. Furthermore, the use of the proposed approach could encourage generators to be built at the place that can create counter flow and this could mitigate the congested state of transmission lines. As a result, the transmission owner could delay further investment for upgrading transmission capacity. Meanwhile, through the use of JDF, the proposed approach allows the transmission utility to deal with multi reference bus users.

6.2 Future Work

This section suggests possible future work to improve or to expand the application of the proposed approach for the wheeling transaction charges.

a) *Extending the use of profit sharing factor, **r**.* The profit sharing factor r is determined according to the willingness of the transmission owner to share this profit with the transmission users. In the present proposed approach, the profit sharing factor r was set irrespectively of the defined transmission user's comments.

   Further application could be possible to use the profit sharing concept in allocating the reward of negative power flow to the transmission user who relieves congestion. This situation occurs when the transmission user, i.e. the generator that involved in the transaction coincidently creates congestion. This transaction is not permissible unless the congestion is relieved first. Therefore, the contribution of the other generator to relieve this congestion i.e. a counterflow generator is required. In this case, the profit sharing, r could be used in distributing the benefit of negative power flow among the three parties. However, further analysis is required to determine the best solution to distribute the profit of the negative power flow to the generators.

b) *Pricing the power loss.* In the present work, the analysis is based on the dc power flow and the transmission network is considered as a lossless network; that is the contribution of losses is neglected. It is possible to use ac power flow so that the use of profit sharing concept can be extended in rewarding the transmission user for reducing transmission losses.

c) *Wheeling charges for simultaneous transaction users.* In the thesis, the wheeling charge for simultaneous transaction user was formulated in such a way that the incentive charges is distributed to the users based on their contribution in the total negative power flow impact the network. Therefore, the more the user contributes in negative power flow the less they pay for the charges. However, the present formulation assumes that the amount of transacted power among the users is equal. Further work is required to formulate an equation which can deal with different simultaneous transacted power users i.e. pool based trading.

d) *Adjustment Factor for revenue recovery.* In the proposed approach, the transmission revenue is reconciled with the use of the profit sharing concept. There is a possibility to use the adjustment factor approach to modify the wheeling charge rate used in the wheeling charge calculation. The adjusted rate is then applied uniformly across the lines until the revenue requirement is met. Unlike the Ramsey pricing method and the other proposed method which through the modification could result in disadvantages to the transmission users as addressed in Chapter 4. In the proposed approach, the modification of wheeling charge rate is applied in combination with the proposed approach i.e. negative flow sharing approach. With the existence of profit sharing factor in the proposed approach, the adjusted wheeling charge rate could be applied in a fairer manner to the transmission user regardless of the transaction locations. However, the pricing adjustments for the purposes of revenue reconciliation should be considered carefully because it is normally subjected to scrutiny by national, federal or state regulatory authorities, who imposed the economic justification.

APPENDIX B - DF's and JDF's Matrix Based on Three Node Network

Consider the three nodes network in Figure 3.4, which is based on the NGC's DCLF Transport model.

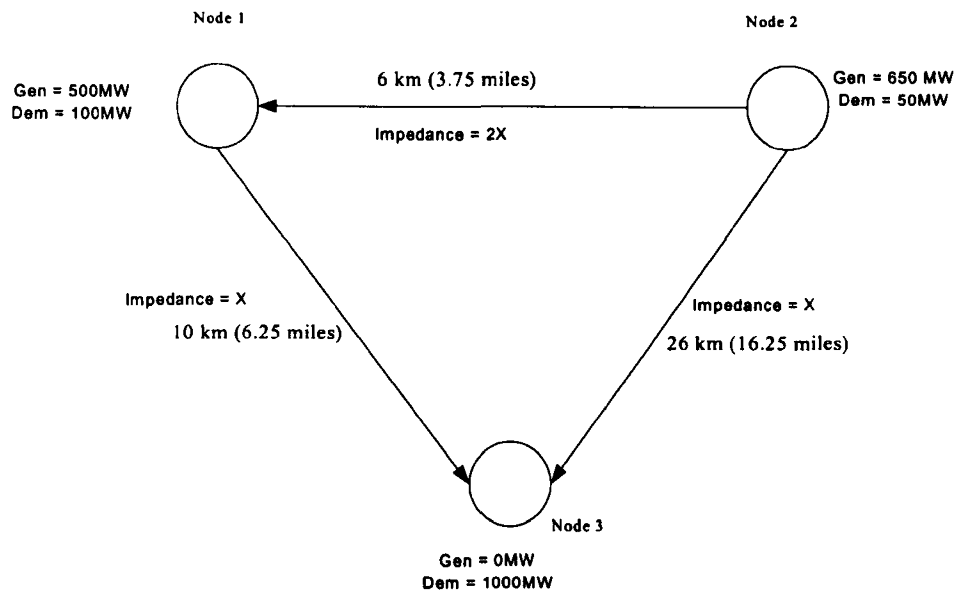

Figure B.1 Three nodes network

<u>*Reference bus 1*</u>

Take bus 1 as a reference bus. The bus susceptance matrix is calculated by using equation (3.30).

$$b_{11} = \frac{1}{1} + \frac{1}{2} = 1.5 \qquad b_{22} = \frac{1}{1} + \frac{1}{2} = 1.5 \qquad b_{33} = \frac{1}{1} + \frac{1}{1} = 2$$

$$b_{12} = -\frac{1}{2} = -0.5 \qquad b_{23} = -\frac{1}{1} = -1$$

$$b_{13} = -\frac{1}{1} = -1 \qquad b_{31} = -\frac{1}{1} = -1$$

$$b_{21} = -\frac{1}{2} = -0.5 \qquad b_{32} = -\frac{1}{1} = -1$$

In matrix form

$$B = \begin{bmatrix} 1.5 & -0.5 & -1 \\ -0.5 & 1.5 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$

As can be seen, matrix B is singular, so it cannot be inverted. Thus the row and the column associated with reference bus has to be reduced in order to obtain the B' matrix.

$$B' = \begin{bmatrix} 1.5 & -1 \\ -1 & 2 \end{bmatrix}$$

Invert the B matrix to get Z (=X) matrix

$$Z = \left[B'\right]^{-1} = \begin{bmatrix} 1.0 & 0.5 \\ 0.5 & 0.75 \end{bmatrix}$$

In order to get A's factors, the matrix Z has to be converted into the original 3^x3 matrix by inserting components zero in the row and column associated with the reference bus 1.

$$Z = \begin{bmatrix} 0 & 0 & 0 \\ 0 & 1.0 & 0.5 \\ 0 & 0.5 & 0.75 \end{bmatrix}$$

The A's distribution factor represents the sensitivity of power flow on line i-j with respect to bus injection i. For instance, the $A_{1-2,1}$ distribution factor is defined as the sensitivity of power flow on line 1-2 with respect to bus injection 1, i.e.

$$A(1-2,1)=\frac{\text{change in line } 1 \rightarrow 2 \text{ flow}}{\text{injection at bus } 1}$$

Based on the Z matrix and the reactance of the line between bus *1* and *2*, the A's distribution factor of line 1 – 2 with respect to buses 1, 2 and 3 can be calculated by using the equation (4.6). The A's distribution factor for lines 1-3 and 2-3 with respective buses 1, 2 and 3 can also be calculated in the similar manner. Table B.1 shows the A's distribution factor of lines 1-2, 1-3 and 2-3 with respect to buses 1, 2 and 3.

Table B.1 – A's distribution factors for three bus system

	Buses		
Lines	**1**	**2**	**3**
1-2	$A_{1\text{-}2,1}$	$A_{1\text{-}2,2}$	$A_{1\text{-}2,3}$
1-3	$A_{1\text{-}3,1}$	$A_{1\text{-}3,2}$	$A_{1\text{-}3,3}$
2-3	$A_{2\text{-}3,1}$	$A_{2\text{-}3,2}$	$A_{2\text{-}3,3}$

In matrix form, the A's distribution factor can be written as;

$$A^m=\begin{bmatrix} A_{1-2,1} & A_{1-2,2} & A_{1-2,3} \\ A_{1-3,1} & A_{1-3,2} & A_{1-3,3} \\ A_{2-3,1} & A_{2-3,2} & A_{2-3,3} \end{bmatrix}$$

where

m is reference bus number

For reference bus 1

$$A_{1-2,1}=\frac{Z_{11}-Z_{21}}{X_{12}}=\frac{0-0}{2}=0$$

$$A_{1-3,3}=\frac{Z_{13}-Z_{33}}{X_{13}}=\frac{0-0.75}{1}=-0.75$$

$$A_{1-2,2}=\frac{Z_{12}-Z_{22}}{X_{12}}=\frac{0-1}{2}=-0.5$$

$$A_{2-3,1}=\frac{Z_{21}-Z_{31}}{X_{23}}=\frac{0-0}{1}=0$$

$$A_{1-2,3} = \frac{Z_{13} - Z_{23}}{X_{12}} = \frac{0 - 0.5}{2} = -0.25 \qquad A_{2-3,2} = \frac{Z_{22} - Z_{32}}{X_{23}} = \frac{1 - 0.5}{1} = 0.5$$

$$A_{1-3,1} = \frac{Z_{11} - Z_{31}}{X_{13}} = \frac{0 - 0}{1} = 0 \qquad A_{2-3,3} = \frac{Z_{23} - Z_{33}}{X_{23}} = \frac{0.5 - 0.75}{1} = -0.25$$

$$A_{1-3,2} = \frac{Z_{12} - Z_{32}}{X_{13}} = \frac{0 - 0.5}{1} = -0.5$$

Hence, the A's distribution factors with respect to the reference bus 1 can be written in the matrix form as shown below

$$A^1 = \begin{bmatrix} 0 & -0.5 & -0.25 \\ 0 & -0.5 & -0.75 \\ 0 & 0.5 & -0.25 \end{bmatrix}$$

Using equation (4.9) and (4.10), the *JDF* can be obtained

$$J_{1-2} = \frac{-\left(A_{12}(1) + A_{12}(2)\right)}{2} = \frac{-\left(0 + (-0.5)\right)}{2} = 0.25$$

$$J_{1-3} = \frac{-\left(A_{13}(1) + A_{13}(3)\right)}{2} = \frac{-\left(0 + (-0.25)\right)}{2} = 0.125$$

$$J_{2-3} = \frac{-\left(A_{23}(2) + A_{23}(3)\right)}{2} = \frac{-\left(0.5 + (-0.25)\right)}{2} = -0.125$$

Therefore, the Justified Distribution Factors, which is independent of the reference node, can be written in the matrix form as shown below

$$JDF^1 = \begin{bmatrix} 0 & -0.5 & -0.25 \\ 0 & -0.5 & -0.75 \\ 0 & 0.5 & -0.25 \end{bmatrix} + \begin{bmatrix} 0.25 & 0.25 & 0.25 \\ 0.375 & 0.375 & 0.375 \\ -0.125 & -0.125 & -0.125 \end{bmatrix} = \begin{bmatrix} 0.25 & -0.25 & 0 \\ 0.375 & -0.125 & -0.375 \\ -0.125 & 0.375 & -0.375 \end{bmatrix}$$

Similarly, by using the same calculation procedure as above, the A's distribution factors with respect to the reference bus 2 and bus 3 can also be obtained.

Reference bus 2

As the matrix B given above is singular, so it cannot be inverted. Thus the row and the column associated with reference bus 2 has to be reduced in order to obtain the $B^{'}$ matrix

$$B^{'} = \begin{bmatrix} 1.5 & -1 \\ -1 & 2 \end{bmatrix}$$

Invert the B matrix to get Z (=X) matrix

$$Z = \left[B^{'}\right]^{-1} = \begin{bmatrix} 1.0 & 0.5 \\ 0.5 & 0.75 \end{bmatrix}$$

In order to get A's factors, the matrix Z has to be converted into the original 3^x3 matrix by inserting components zero in the row and column associated with the reference bus 2.

The matrix Z associated with the reference bus 2 can be written as

$$Z = \begin{bmatrix} 1 & 0 & 0.5 \\ 0 & 0 & 0 \\ 0.5 & 0 & 0.75 \end{bmatrix}$$

The A's distribution factor for each line with respectively bus can be calculated as below

$$A_{1-2,1} = \frac{Z_{11} - Z_{21}}{X_{12}} = \frac{1-0}{2} = 0.5 \qquad A_{1-3,3} = \frac{Z_{13} - Z_{33}}{X_{13}} = \frac{0.5-0.75}{1} = -0.25$$

$$A_{1-2,2} = \frac{Z_{12} - Z_{22}}{X_{12}} = \frac{0-0}{2} = 0 \qquad A_{2-3,1} = \frac{Z_{21} - Z_{31}}{X_{23}} = \frac{0-0.5}{1} = -0.5$$

$$A_{1-2,3} = \frac{Z_{13} - Z_{23}}{X_{12}} = \frac{0.5-0}{2} = 0.25 \qquad A_{2-3,2} = \frac{Z_{22} - Z_{32}}{X_{23}} = \frac{0-0}{1} = 0$$

$$A_{1-3,1} = \frac{Z_{11} - Z_{31}}{X_{13}} = \frac{1-0.5}{1} = 0.5 \qquad A_{2-3,3} = \frac{Z_{23} - Z_{33}}{X_{23}} = \frac{0-0.75}{1} = -0.75$$

$$A_{1-3,2} = \frac{Z_{12} - Z_{32}}{X_{13}} = \frac{0-0}{1} = 0$$

Hence, the A's distribution factors with respect to the reference bus 2 can be written in the matrix form as

$$A^2 = \begin{bmatrix} 0.5 & 0 & 0.25 \\ 0.5 & 0 & -0.25 \\ -0.5 & 0 & -0.75 \end{bmatrix}$$

Using equations (4.9) and (4.10) , the *JDF* can be obtained

$$J_{1-2} = \frac{-\left(A_{12}(1) + A_{12}(2)\right)}{2} = \frac{-\left(0.5+0\right)}{2} = -0.25$$

$$J_{1-3} = \frac{-\left(A_{13}(1) + A_{13}(3)\right)}{2} = \frac{-\left(0.5+(-0.25)\right)}{2} = -0.125$$

$$J_{2-3} = \frac{-\left(A_{23}(2) + A_{23}(3)\right)}{2} = \frac{-\left(0 + (-0.75)\right)}{2} = 0.375$$

Therefore, JDF with respect to the reference bus 2

$$JDF^2 = \begin{bmatrix} 0.5 & 0 & 0.25 \\ 0.5 & 0 & -0.25 \\ -0.5 & 0 & -0.75 \end{bmatrix} + \begin{bmatrix} -0.25 & -0.25 & -0.25 \\ -0.125 & -0.125 & -0.125 \\ 0.375 & 0.375 & 0.375 \end{bmatrix} = \begin{bmatrix} 0.25 & -0.25 & 0 \\ 0.375 & -0.125 & -0.375 \\ -0.125 & 0.375 & -0.375 \end{bmatrix}$$

Reference bus 3

Similarly as above, since the matrix B is singular and it cannot be inverted, the row and the column associated with reference bus 3 has to be reduced in order to obtain the $B^{'}$ matrix

$$B^{'} = \begin{bmatrix} 1.5 & -0.5 \\ -0.5 & 1.5 \end{bmatrix}$$

Invert the B matrix to get Z (=X) matrix

$$Z = \left[B^{'}\right]^{-1} = \begin{bmatrix} 0.75 & 0.25 \\ 0.25 & 0.75 \end{bmatrix}$$

In order to get A's factors, the matrix Z has to be converted into the original 3^x3 matrix by inserting components zero in the row and column associated with the reference bus 3.

The matrix Z associated with the reference bus 3 can be written as

$$Z = \begin{bmatrix} 0.75 & 0.25 & 0 \\ 0.25 & 0.75 & 0 \\ 0 & 0 & 0 \end{bmatrix}$$

The A's distribution factor for each line with respectively bus can be calculated as below

$$A_{1-2,1} = \frac{Z_{11} - Z_{21}}{X_{12}} = \frac{0.75 - 0.25}{2} = 0.25 \qquad A_{1-3,3} = \frac{Z_{13} - Z_{33}}{X_{13}} = \frac{0 - 0}{1} = 0$$

$$A_{1-2,2} = \frac{Z_{12} - Z_{22}}{X_{12}} = \frac{0.25 - 0.75}{2} = -0.25 \qquad A_{2-3,1} = \frac{Z_{21} - Z_{31}}{X_{23}} = \frac{0.25 - 0}{1} = 0.25$$

$$A_{1-2,3} = \frac{Z_{13} - Z_{23}}{X_{12}} = \frac{0 - 0}{2} = 0 \qquad A_{2-3,2} = \frac{Z_{22} - Z_{32}}{X_{23}} = \frac{0.75 - 0}{1} = 0.75$$

$$A_{1-3,1} = \frac{Z_{11} - Z_{31}}{X_{13}} = \frac{0.75 - 0}{1} = 0.75 \qquad A_{2-3,3} = \frac{Z_{23} - Z_{33}}{X_{23}} = \frac{0 - 0}{1} = 0$$

$$A_{1-3,2} = \frac{Z_{12} - Z_{32}}{X_{13}} = \frac{0.25 - 0}{1} = 0.25$$

Hence, the A's distribution factors with respect to the reference bus 3 can be written in the matrix form as

$$A^3 = \begin{bmatrix} 0.25 & -0.25 & 0 \\ 0.75 & 0.25 & 0 \\ 0.25 & 0.75 & 0 \end{bmatrix}$$

Using equations (4.9) and (4.10), the *JDF* can be obtained

$$J_{1-2} = \frac{-\left(A_{12}(1) + A_{12}(2)\right)}{2} = \frac{-\left(0.25 + (-0.25)\right)}{2} = 0$$

$$J_{1-3} = \frac{-\left(A_{13}(1) + A_{13}(3)\right)}{2} = \frac{-\left(0.75 + 0\right)}{2} = -0.375$$

$$J_{2-3} = \frac{-(A_{23}(2) + A_{23}(3))}{2} = \frac{-(0.75+0)}{2} = -0.375$$

Therefore, JDF with respect to the reference bus 3

$$JDF^3 = \begin{bmatrix} 0.25 & -0.25 & 0 \\ 0.75 & 0.25 & 0 \\ 0.25 & 0.75 & 0 \end{bmatrix} + \begin{bmatrix} 0 & 0 & 0 \\ -0.375 & -0.375 & -0.375 \\ -0.375 & -0.375 & -0.375 \end{bmatrix} = \begin{bmatrix} 0.25 & -0.25 & 0 \\ 0.375 & -0.125 & -0.375 \\ -0.125 & 0.375 & -0.375 \end{bmatrix}$$

It can be observed that the JDF matrices calculated based on different reference buses are identical as shown in Table B.2; hence equation (4.12) is verified.

Table B.2 - A and JDF matrices based on different reference buses.

	Reference Bus 1	Reference Bus 2	Reference Bus 3
Susceptance Matrix B (no. of nodes x no. of nodes)	1.5 -0.5 -1 -0.5 1.5 -1 -1 -1 2	1.5 -0.5 -1 -0.5 1.5 -1 -1 -1 2	1.5 -0.5 -1 -0.5 1.5 -1 -1 -1 2
Distribution Factors (A) (no.of lines x no. of nodes)	0 -0.5 -0.25 0 -0.5 -0.75 0 0.5 -0.25	0.5 0 0.25 0.5 0 -0.25 -0.5 0 -0.75	0.25 -0.25 0 0.75 0.25 0 0.25 0.75 0
Justified Distribution Factor (JDF) (no. of lines x no. of nodes)	0.25 -0.25 0 0.375 -0.125 -0.375 -0.125 0.375 -0.375	0.25 -0.25 0 0.375 -0.125 -0.375 -0.125 0.375 -0.375	0.25 -0.25 0 0.375 -0.125 -0.375 -0.125 0.375 -0.375

APPENDIX C - Power Flows Sensitivity based on IEEE 14 bus system

Table C.1 - Power flows sensitivity due to transactionT1

BUS i-j	Base Case	T1 in	ΔP_{neg}	T1+T2+T3	T1 out	ΔP_{neg}
1-2	147.8164	160.0268		141.2000	128.9896	
1-5	71.1486	78.9361		77.7605	69.9730	
2-3	70.0100	72.0716		64.5944	62.5328	
2-4	55.1424	59.4569		63.2087	58.8942	
2-5	40.9623	46.7974		51.6960	45.8618	
3-4	-24.1897	-22.1281	-2.0616	-9.6053	-11.6669	-2.0616
4-5	-61.7437	-55.7189	-6.0248	-51.2006	-57.2255	-6.0248
4-7	28.3506	28.5724		35.9962	35.7743	
4-9	16.5459	16.6754		21.0080	20.8785	
5-6	42.7685	42.4150	-0.3534	50.6564	51.0098	-0.3534
6-11	6.7177	6.5049	-0.2128	6.9432	7.1559	-0.2128
6-12	7.6068	7.5756	-0.0312	9.3105	9.3417	-0.0312
6-13	17.2492	17.1401	-0.1091	23.2086	23.3177	-0.1091
7-8	0.000	0.000		0.0000	0.0000	
7-9	28.3510	28.5728		35.9967	35.7748	
9-10	5.7576	5.9690		5.5291	5.3178	
9-14	9.6414	9.7816		21.9780	21.8378	
10-11	-3.2315	-3.0195	-0.2120	-3.4587	-3.6707	-0.2120
12-13	1.5067	1.4755	-0.0312	3.2103	3.2415	-0.0312
13-14	5.2586	5.1184	-0.1402	12.9220	13.0622	-0.1402

Table C.2 - Power flows sensitivity due to transaction T2

BUS i-j	Base Case	T2 in	ΔP_{neg}	T1+T2+T3	T2 out	ΔP_{neg}
1-2	147.8164	143.9188	-3.8976	141.2000	145.0976	-3.8976
1-5	71.1486	75.0421		77.7605	73.8669	
2-3	70.0100	73.1727		64.5944	61.4317	
2-4	55.1424	61.7613		63.2087	56.5898	
2-5	40.9623	47.2839		51.6960	45.3753	
3-4	-24.1897	-21.0270	-3.1627	-9.6053	-12.7680	-3.1627
4-5	-61.7437	-63.3587		-51.2006	-49.5857	
4-7	28.3506	35.5472		35.9962	28.7996	
4-9	16.5459	20.7460		21.0080	16.8079	
5-6	42.7685	51.3678		50.6564	42.0570	
6-11	6.7177	7.3716		6.9432	6.2893	
6-12	7.6068	9.3734		9.3105	7.5439	
6-13	17.2492	23.4287		23.2086	17.0291	
7-8	0.000	0.0000		0.0000	0.0000	
7-9	28.3510	35.5477		35.9967	28.8000	
9-10	5.7576	5.1010	-0.6566	5.5291	6.1857	-0.6566
9-14	9.6414	21.6950		21.9780	9.9244	
10-11	-3.2315	-3.8869		-3.4587	-2.8032	
12-13	1.5067	3.2732		3.2103	1.4438	
13-14	5.2586	13.2049		12.9220	4.9756	

Table C.3 - Power flows sensitivity due to transaction T3

BUS i-j	Base Case	T3 in	ΔP_{neg}	T1+T2+T3	T3 out	ΔP_{neg}
1-2	147.8164	132.8872	-14.9292	141.2000	156.1292	-14.9292
1-5	71.1486	66.0794	-5.0692	77.7605	82.8297	-5.0692
2-3	70.0100	59.3700	-10.640	64.5944	75.2343	-10.640
2-4	55.1424	52.2752	-2.8672	63.2087	66.0759	-2.8672
2-5	40.9632	39.5411	-1.4221	51.6960	53.1181	-1.4221
3-4	-24.1897	-14.8297	-9.3600	-9.6053	-18.9653	-9.3600
4-5	-61.7437	-55.6105	-6.1332	-51.2006	-57.3339	-6.1332
4-7	28.3506	28.5777		35.9962	35.7691	
4-9	16.5459	16.6784		21.0080	20.8755	
5-6	42.7685	42.4105	-0.3580	50.6564	51.0144	-0.3580
6-11	6.7177	6.5020	-0.2157	6.9432	7.1588	-0.2157
6-12	7.6068	7.5751	-0.0317	9.3105	9.3422	-0.0317
6-13	17.2492	17.1383	-0.1109	23.2086	23.3196	-0.1109
7-8	0.000	0.0000		0.0000	0.0000	
7-9	28.3510	28.5781		35.9967	35.7696	
9-10	5.7576	5.9744		5.5291	5.3123	
9-14	9.6414	9.7842		21.9780	21.8352	
10-11	-3.2315	-3.0152	-0.2163	-3.4587	-3.6749	-0.2163
12-13	1.5067	1.4750	-0.0317	3.2103	3.2420	-0.0317
13-14	5.2586	5.1158	-0.1428	12.9220	13.0648	-0.1428

ΔP_{neg} = Negative power flow impact

APPENDIX D - A's and JDF's Distribution Factors for 5 bus, 9 bus and IEEE-14 bus Systems

i) 5 bus system

JDF =

```
0.4214 -0.4214 -0.2071 -0.2500 -0.3643
0.1857  0.0286 -0.1857 -0.1429 -0.0286
0.1071  0.1786 -0.1786 -0.1071  0.0833
0.1238  0.1810 -0.1048 -0.1810  0.0603
0.3349  0.3635  0.2206  0.1825 -0.3635
0.1000  0.0143  0.4429 -0.4429 -0.1381
0.0746  0.0460  0.1889  0.2270 -0.2270
```

ii) 9 bus system

JDF =

0.5000	-0.5000	-0.5000	-0.5000	-0.5000	-0.5000	-0.5000	-0.5000	-0.5000
0.4324	0.0711	-0.1827	0.4324	-0.4324	-0.1827	-0.0347	0.0711	0.3076
-0.0676	-0.4289	-0.6827	-0.0676	0.0676	-0.6827	-0.5347	-0.4289	-0.1924
-0.5000	-0.5000	0.5000	-0.5000	-0.5000	-0.5000	-0.5000	-0.5000	-0.5000
0.0411	-0.3202	0.4260	0.0411	0.1763	0.4260	-0.4260	-0.3202	-0.0837
-0.0858	-0.4471	0.2991	-0.0858	0.0494	0.2991	0.4471	-0.4471	-0.2106
0.5000	-0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000
-0.2569	0.3818	0.1279	-0.2569	-0.1218	0.1279	0.2760	0.3818	-0.3818
-0.4376	0.2011	-0.0527	-0.4376	-0.3024	-0.0527	0.0953	0.2011	0.4376

iii) IEEE-14 bus system

JDF=

0.4190	-0.4190	-0.3275	-0.2484	-0.1915	-0.2100	-0.2381	-0.2381	-0.2326	-0.2286	-0.2194	-0.2118	-0.2132	-0.2241
0.1947	0.0327	-0.0588	-0.1378	-0.1947	-0.1761	-0.1480	-0.1480	-0.1535	-0.1575	-0.1666	-0.1743	-0.1729	-0.1620
0.2523	0.2797	-0.2797	0.1010	0.1492	0.1335	0.1097	0.1097	0.1143	0.1177	0.1255	0.1320	0.1308	0.1215
0.1297	0.1870	-0.0136	-0.1870	-0.0860	-0.1189	-0.1688	-0.1688	-0.1591	-0.1519	-0.1357	-0.1221	-0.1246	-0.1440
0.1072	0.1846	0.0360	-0.0923	-0.1846	-0.1644	-0.1088	-0.1088	-0.1177	-0.1242	-0.1390	-0.1515	-0.1492	-0.1315
-0.1583	-0.1310	0.3097	-0.3097	-0.2614	-0.2771	-0.3010	-0.3010	-0.2963	-0.2929	-0.2852	-0.2787	-0.2798	-0.2891
-0.1007	-0.0208	0.2060	0.4019	-0.4019	-0.1396	0.2577	0.2577	0.1801	0.1233	-0.0059	-0.1143	-0.0946	0.0600
0.3076	0.3106	0.3189	0.3262	0.2965	0.1002	-0.3262	-0.3262	-0.1392	-0.0966	0.0001	0.0813	0.0665	-0.0403
0.1240	0.1267	0.1316	0.1358	0.1185	0.0039	-0.0408	-0.0408	-0.1358	-0.1110	-0.0546	-0.0071	-0.0158	-0.0833
0.3268	0.3221	0.3089	0.2975	0.3446	-0.3446	0.1265	0.1265	0.0346	-0.0328	-0.1859	-0.3146	-0.2911	-0.1078
0.1711	0.1683	0.1603	0.1534	0.1817	0.3690	0.0505	0.0505	-0.0048	-0.1161	-0.3690	0.3395	0.3164	0.1356
0.2460	0.2456	0.2445	0.2434	0.2476	0.2751	0.2283	0.2283	0.2202	0.2299	0.2521	-0.2751	0.0763	0.1573
0.2459	0.2445	0.2404	0.2369	0.2514	0.3476	0.1840	0.1840	0.1555	0.1897	0.2673	-0.0427	-0.3476	-0.0645
0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000	0.5000
0.0403	0.0433	0.0516	0.0589	0.0292	-0.1671	0.4065	0.4065	-0.4065	-0.3639	-0.2672	-0.1861	-0.2008	-0.3166
0.2682	0.2711	0.2791	0.2860	0.2576	0.0704	0.3890	0.3890	0.4444	-0.4444	-0.1914	0.1000	0.1231	0.3039
0.2423	0.2441	0.2494	0.2540	0.2353	0.1115	0.3220	0.3220	0.3586	0.3147	0.2149	0.0520	0.0055	-0.3586
0.0862	0.0890	0.0970	0.1039	0.0756	-0.1116	0.2069	0.2069	0.2623	0.3736	-0.3736	-0.0821	-0.0590	0.1218
-0.1546	-0.1550	-0.1562	-0.1572	-0.1530	-0.1255	-0.1723	0.1723	-0.1804	-0.1707	-0.1485	0.3243	-0.3243	-0.2433
0.0812	0.0794	0.0741	0.0695	0.0882	0.2120	0.0015	0.0015	-0.0351	0.0088	0.1086	0.2715	0.3179	-0.3179

APPENDIX E – Generation and Demand Data for Base Case

Table E.1 - 5 bus system

Bus	Generation (MW)	Demand (MW)
1	100	10
2	50	20
3	0	40
4	0	50
5	30	60

Table E.2 - 9 bus system

Bus	Generation (MW)	Demand (MW)
1	67	
2	163	
3	85	
4		
5		90
6		
7		100
8		
9		125

Table E.3 - IEEE 14 bus system

Bus	Generation (MW)	Demand(MW)
1	219	0
2	40	21.7
3		94.2
4		47.8
5		7.6
6		11.2
7		0
8		0
9		29.5
10		9.0
11		3.5
12		6.1
13		13.5
14		14.9

APPENDIX F – Transmission Lines Parameters and Costs

Table F.2- 9 bus system

Bus i	Bus j	Reactance (p.u)	Transmission Cost (£)
1	4	0.0576	100.10^3
4	5	0.0920	100.10^3
5	6	0.1700	100.10^3
3	6	0.0586	100.10^3
6	7	0.1008	100.10^3
7	8	0.0720	100.10^3
8	2	0.0625	100.10^3
8	9	0.1610	100.10^3
9	4	0.0850	100.10^3

APPENDIX G - Ramsey Pricing Scheme

Introduction

Ramsey is a term used first to describe issues in public utility regulation, where there are big fixed costs and low marginal costs, and hence increasing returns to scale, and departures from marginal cost were necessary to recoup the fixed costs. Since marginal cost pricing would not meet the budget constraint of the enterprise, Ramsey and others (before him) examined the issue of how best to price the good or service. In particular, he focused on classic notions of economic efficiency, as measured by consumer surplus, and like most such analysis, ignoring distributional issues.

Ramsey's insight (he was not the first it turns out), was that pricing similar to a monopolist was economically efficient, if both could engage in price discrimination. The less elastic the demand for the good (the higher the willingness to pay), the less consumer (social) surplus that was lost.

The Ramsey solution was not the monopolist solution, however, because Ramsey limited the increases over marginal cost to only that necessary to pay for the fixed costs. Ramsey would price according to what the market would bear, but only up to a point when the enterprise met its budget constraint. The Ramsey solution is often used to some degree by regulators, but with some limitations, because it has some problems.

One illustration of this is from the optimal tax theory, where it was quickly shown that a Ramsey solution would involve shifting taxes away from many luxury goods, and more problematic, to things like life saving medicines. For example, under Ramsey pricing, one would have very high taxes on insulin, and use this revenue to say pay for roads. Any medicine that treated a severe illness was target for a Ramsey tax. The demand was "inelastic" because people really needed it.

Monopolies of one sort or another were fascinated with Ramsey pricing, because it provides a nice rationale for behaviour that looked a lot line what a monopolist wanted to do. Thus, for example, in the early 80s the railroads claimed that deregulation of "captive" shippers of coal and grain, was " Ramsey efficient", because they were recouping fixed costs from those who had co alternatives, and hence, were relatively price inelastic.

The big problem with Ramsey pricing is that everyone loves to push the price discrimination part, which is pricing according to what people are willing to pay, but there is considerably less enthusiasm for the other part, which is the budget constraint. And, without the government regulation of the budget constraint, and just have monopoly pricing, which is not in fact efficient, in most cases, not to mention the ethical issues, or the rather messy empirical realities of industry pricing practices.

Ramsey Pricing Model

In general, Ramsey pricing is the solution to the problem of maximising social welfare, subject to a break-even constraint for a monopolist. This pricing is a mixture of marginal cost pricing and monopoly pricing and known as "second best pricing". The math involved in the formal development of the Ramsey pricing model can be briefly illustrated. In particular consider the problem

Maximize:

$$W = \int_0^x P(Q)dQ - c(x)dx \qquad \text{Subject to:} \qquad \pi(x) \geq \pi_0$$

This says: maximize social welfare (as before), but this time subject to a constraint that says (accounting) profits have to be some minimal amount. Formally, this can be solved using a mathematical procedure called the Lagrangian Multiplier Procedure, which involves rewriting the objective function (welfare max) so that it directly incorporates the constraint. This would look like the following:

$$L = W(x) + \mu(\pi(x))$$

W(x) is the original welfare function and B(x) is the minimum profit constraint. The term:is called a "Lagrange Multiplier." It reflects the extent to which the profitability constraint matters,....how much bite it has.

When this problem is solved, the end result is the following.

$$\frac{P - MC}{P} = -\left(\frac{\mu}{1+\mu}\right) * \frac{1}{\eta}$$

Notice that much of this is familiar. We have the Lerner Index on the left of the equal sign, and the second term on the right hand side is the inverse price elasticity of demand. So if we ignore the term in brackets, we have the conventional monopoly pricing outcome. The term in the brackets is an adjustment to the monopoly outcome to reflect the altered goal of Ramsey Pricing.

Notice that the term in brackets depends on the Lagrange Multiplier, :, which reflects the extent to which the profit constraint is binding. In effect, we have the monopoly outcome, that is scaled or adjusted by a weighting factor that depends on the minimum profitability constraint. The value of the term in brackets reflects the size of the adjustment from the monopoly outcome. In effect, we are adjusting the monopoly outcome as much as possible, to get the Lerner Index as close to zero as possible, while still honoring the profitability constraint.

The expression in brackets is referred to as the "Ramsey Number," often labeled "k" for simplicity. Thus:

$k = -\left(\frac{\mu}{1+\mu}\right)$ Which means $\frac{P-MC}{P} = -\left(\frac{\mu}{1+\mu}\right) * \frac{1}{\eta}$ that $\frac{P-MC}{P} = k * \frac{1}{\eta}$

becomes

This means you deviate from the monopoly outcome (or said the reverse, you deviate from the competitive or optimal outcome) in a specific way so as to get an "almost optimum" outcome. Notice that if:

K = -1, you have the monopoly outcome

K = 0, you have the competitive outcome

0 < k < 1, you have a Ramsey outcome somewhere in between

The Ramsey Number indicates how binding the minimum profit constraint is, and how much you need to adjust the Lerner Index to allow for the profit constraint. As : approaches 1, the optimal outcome approaches the monopoly outcome. In other words, the pricing gets closer to monopoly pricing because added profits are needed to satisfy the constraints. The primary conclusion that emerges from Ramsey Pricing Analysis is the mark up on Marginal Cost should be Inversely Proportional to the Price Elasticity of Demand.

Example

Suppose that a two-product natural monopolist has the following cost structure:

TC(Q1,Q2) = $1000 + 50Q1 + 50Q2

Demands:

Q1 = 150 - P1

Q2 = 200 - 2P2

Note that MC-pricing fails to meet the zero-profit constraint. Thus each product's price must exceed MC. But by how much?

For this independent demand case, the Ramsey-optimal pricing scheme implies cutting the marginal-cost output for each product by the same proportion until zero profit is realized.

In this example, the marginal-cost outputs are Q1 = 100 = Q2. If the two marginal-cost outputs are to be reduced by the smallest proportion such that profit is zero, then let "z" = (1-smallest proportion) be the largest proportion of the marginal-cost Q that solves the Ramsey-optimal pricing problem:

Profit = 0 = P1(Q1=100z)*100z + P2(Q2=100z)*100z - 1000 - 50*100z - 50*100z,

where inverse demands P1(Q1=100z) = 150-100z, P2(Q2=100z) = 100-50z.

Solving for "z" gives the following: 15,000z - 15,000z**2 - 1000 = 0; dividing across by -1000 gives

15z**2 - 15z + 1 = 0.

Quadratic equation: z = (15 +/- sqrt(225 - 4*15*1))/30 = (15 +/- 12.845)/30 = 0.9282, 0.072. Solution should be 0.9282.

Check: Profit = 13,923 - 12,923 - 1000 = 0!!!

What are the implied Ramsey prices? P1 = 150 - 92.82 = $57.18; P2 = 100 - 46.41 = $53.59. Note: Using the elasticities at P = $50 as an approximation, the constant k in the Ramsey equation above is approximately 0.064.

Ramsey Scheme for Pricing Transmission Services

In the context of transmission service pricing, Ramsey pricing scheme modified the transmission optimum prices by an amount proportional to the demand elasticity. This causes the minimum loss economic efficiency while ensuring the revenue recovery of the transmission utility. The resultant modified transmission prices are considered as a second best set of prices that ensures revenue recovery without encouraging sub-optimal behaviour from users (i.e. both generators and demands) by giving distorted price signals. The users of the transmission system choose the set of circuit flows that maximise the consumer net benefit subject to the operational constraints (i.e. generator capacity and mesh voltage) by changing the load and generator bid prices. The price elacticities may be determined by perturbing the transmission prices around an operating point (i.e. preferably optimum prices) and observing the resultant change in circuit flows as users of the transmission system. This scheme has the disadvantage since it penalising the least flexible transmission users more than others, thereby introducing differential treatment during revenue reconciliation which may not be acceptable to the users in general.