FOUNDATIONS OF
PRICING AND INVESTMENT IN
ELECTRICITY TRANSMISSION

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Declaration

No portion of the work referred to in this thesis has been submitted in support of an application for another degree or qualification of this or any other university, or other institution of learning.

The ideas and work developed by the author represent his own thinking and not necessary represent the position of the company he works for.

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Abstract

Transmission pricing has become a central issue in the discussions regarding the redesign of deregulated electricity markets. In that frame, open access to the transmission system is one of the fundamental topics to allow competition among agents in the energy market. Although transmission systems costs represent close to 10% of the energy market price, they have a significant impact on relative competitiveness among participants in the energy market as well as on short and long term economic efficiency of the whole electricity industry.

This research analyses how to deal with transmission costs, covering short and long term issues in electricity transmission pricing and their link with the energy market. Transmission short run marginal cost (SRMC) schemes are studied and particularly, in relation to financial and physical transmission rights. Variants of those schemes are currently in use in the United States and a similar scheme based on firm access rights (FAR) has been proposed in the New Electricity Trading Arrangements (NETA) for England and Wales. This research concludes that transmission rights schemes work well as a complement of the energy market but they do not and cannot resolve the problem of cost allocation of the existent transmission assets and investments. The reasons are simple: SRMC do not have a direct relationship with transmission investment costs and transmission business is a natural monopoly. Therefore an efficient transmission access pricing methodology is required to allow the recovery of transmission investment costs. For that reason, transmission pricing based on the concept of "economically adapted network" (EAN) is examined and recommended. Prices derived from the EAN have the advantage to be in tune with the maximum revenue allowed to the owner of transmission assets and facilitate the optimal allocation of transmission costs among users. Fundamental features of the EAN scheme have been illustrated on a number of examples including IEEE 24 bus Reliability Test System.

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CHAPTER 1

Main issues in transmission pricing

Summary

This chapter describes the role of the electricity transmission network in the new deregulated schemes in practise over the world and the main challenges regarding the search for an efficient method for transmission pricing. Open and non discriminatory access to the transmission network capacity is analysed as a pillar of competition in the energy market. The objectives, scope and main contributions of this research are addressed. An outline of the thesis structure is also given.

1.1 Overview

Under the new electricity deregulated market schemes in practise over the world, transmission pricing has been a focus of research and discussions over the past years. This has been driven mainly by the importance that open access to the transmission system capacity has on the overall economic efficiency and competitiveness in the energy market. Although transmission costs represent only like 10% of the energy market costs and no more than 4% of the final customers bill, transmission capacity constraints and transmission line outages can have a significant impact on the locational costs of electricity. Therefore, transmission system capacity affects the relative competitiveness of generators and customers connected to the electricity network. Hence the importance to develop an efficient pricing scheme for electricity transmission in tune with the energy market pricing scheme and able to provide efficient signals in the short and long term.

Experiences in transmission pricing over the world are diverse regarding how to front the main issues. The reasons for that diversity are closely related to the economic principles and regulatory beliefs that drive the design of the energy market and the adoption of a pricing scheme as part of the new deregulated electricity industry.

1.2 Role of transmission pricing

Network pricing is one of the most critical issues in assuring the successful operation of a market based electricity industry (Mutale, J., 2000). Pricing of network services has become an important subject because of the role the networks play in facilitating competition in the generation and retail segments of the industry. Owners of transmission facilities must provide open and non discriminatory access to the available transport capacity of the transmission network and cost reflexive prices should be charged to the users.

The economic theory of electricity transmission pricing says that the first-best price of electricity at each node on a network equals the marginal cost of providing electricity at that node (Green, R., 1998). The electricity must be generated and delivered to that node considering transmission constraints and electrical losses. If transmission constraints are binding, it means the power flow through a line is at the limit of its secure transmission capacity, then cheap but distant generation must be replaced with more expensive local generation in order to limit the power flow. In the constrained area the optimal price of electricity rises to the marginal cost of the local generation. Therefore a set of nodal prices arises in the short term operation of the electricity system and sends signals regarding the value of electricity at any time and location on the transmission network. In the long term nodal prices and the price differentials between nodes arise as powerful signals to drive investments to upgrade the capacity of the transmission network.

Although the basic economic principles are well known, the design of an efficient pricing scheme for electricity transmission is not a straight forward task. Real networks characteristics and energy market imperfections impede that the economic theory of perfect competition works well to price the use of the network. Nevertheless the application of the main principles can help to formulate effective schemes for transmission pricing.

International experiences in electricity transmission regulation show a wide variety of pricing schemes, covering methods based on short run marginal costs (SRMC) at different locations on the network, like transmission rights schemes in usage in several systems in the United States, long run marginal costs of transmission (LRMC) and the determination of a reference network or 'economically adapted network' (EAN), and finally the simple postage stamp methods.

From the regulatory perspective, transmission pricing has a fundamental role in the design of a competitive energy market. The main issues to consider in the definition of a transmission pricing scheme are presented below.

- **Cost allocation of the existent network**

  The existent assets of the transmission network are sunk costs, therefore these costs must be charged to the users of the network (generators and consumers) in a way that does not distort the short term signals provided in the energy market. In that sense the short term signals for the competitive generation despatch and supply must not be affected by transmission charges. It means that transmission prices designed to recover the costs of the existent network must be fixed costs that act like postage stamp charges, for instance. The application of stamped charges does not mean that those charges must be flat and calculated in a simple distributive way. The allocation of costs of the existent transmission assets is a relevant topic and one of the focus of this research.

  On other hand, the allocation of costs must be performed by the regulator due to the re-distributive nature of the task. Nobody in the energy market would like to pay a transmission charge bigger than its competitor and therefore the payment of those charges must be a regulatory obligation for all participants in the energy market.

- **Maximum revenue allowed (price control)**

  The electricity transmission business is a natural monopoly, then the allowed revenues for transmission networks must be regulated by means of some kind of price control. Thus a relevant topic is the regulatory definition of the total revenue for every transmission asset owner or the definition of the maximum revenue attributable to every one of the assets in the transmission system. Another way to deal with this issue is the determination of a reference network or 'economically adapted network' that allows the calculation of optimal transmission capacities for everyone of the elements in the network, and therefore to determine the investment cost of such an ideal network.

  One important aspect in the regulatory definition of the maximum revenues allowed is the periodicity to perform such price control, for example every four or five years. During the price control period some mechanism to approve upgrades in the transmission network when relevant changes in generation or demand occur must be implemented. Additionally, a way to update the regulated revenues in the price control period is the setting of price indexes together with the initial setting of the maximum revenues. Those price indexes must be cost reflective of the main cost components affecting every specific asset and therefore, they can be defined for different kinds of transmission assets (transmission lines, power transformers, reactive power compensation equipment, etc.) and also for operation and maintenance costs. A fair and long term definition of the price control by the regulator will incentive transmission owners to perform reinforcements and new investments in the network.

- **Driving investments**

  A fundamental piece of regulation is network development when it probes to be economically convenient from the system point of view. In that sense, participants in the energy market can perform an ex-ante estimation of the impact that a network reinforcement will have for them if the right prices are in place. Thereby willingness to pay the investment cost of new transmission assets can be identified by participants if they have the right pricing signals. Transmission investments are facilitated when only one or few users collect the benefits of network development. On the other side, when many users capture the benefits of additional transmission capacity it is very difficult to achieve a collective agreement among users, and then the regulatory hand is required. Among transmission investments with many users having benefits are those reinforcements that improve the quality and security of service of the system. Market driven investments can be a reality in a world where co-operation becomes as important as competition.

Another important aspect is the timing required to construct new transmission facilities. Usually a long duration period of at least 2 or 3 years is required to construct a new transmission line or substation and then all kind of agreements about investments costs and allocation among users must be signed by the parties before the decision to start constructing is made.

- **Short and long term efficiency**
  The interaction between short and long run costs of the network and the energy market pricing scheme must be considered. For instance, transmission losses can be considered as part of the energy market and then to define prices that contains a loss component or they can be included as part of the access market. It means that a consistent and stable scheme of energy and access policies and pricing must be designed for the long term.

- **Time of use signals**
  A relevant issue regarding the interaction between the energy and access market pricing scheme is the consideration of time of use signals in the calculation of transmission prices. Alternatively, they must be left only as short run signals in the energy market. Maximum demands for transmission do not follow the same temporal pattern of demand. Moreover, the power flow transported through a transmission line depends on the combination of generation injections and demand

withdraws at both sides of the line. Therefore, some kind of time of use signal attributable to the maximum usage of every line in the network is a valuable piece of an economically efficient transmission pricing scheme.

- **Location specific signals**
  Another issue of interaction among energy and access market pricing is the consideration of location specific signals in the calculation of transmission prices. Alternatively, they must be left only as short run signals in the energy market. Location specific transmission prices take into account the impact of an user at different locations in the network. This is another valuable piece of an economically efficient transmission pricing scheme.

1.3 Open access and energy market

Open and non discriminatory access to the transmission system is one of the pillar to facilitate competition in the energy market. Transmission owners must provide open access to the transmission network and it means open access to inject power by generators and to withdraw power by consumers taking into account transmission constraints according to the co-ordination of a system operator. Prices in the energy market can be defined in two ways depending on the consideration or not of the transmission network. One way is a “one node” pricing system where the transmission network is ignored but some compensation mechanisms must be in practise to solve transmission constraints through changes on the original despatch. The other way is a “multi-nodal” pricing system where a locational representation of the transmission network is considered that can be either “zonal” or “nodal”. Energy market pricing schemes are analysed in section 2.5.2.

Most of the experiences in open access pricing move around two main methodologies: *value-based methods* or methods driven by generations costs and *cost-based methods* or methods driven by transmission investment costs. Those methods are described in more detail in section 2.4. Basically value-based methods determine the value of transmission as the difference of the energy market prices between two nodes in the network. Prices in a competitive energy market must always reflect short run marginal costs (SRMC) and therefore, the value of transmission is equal to the SRMC difference between two nodes. However it is a well known fact that pricing the use of the network with SRMC produces a revenue surplus that is not necessarily matched with the transmission investment costs of the network. So depending on the network transmission capacity, the SRMC surplus can be lower or higher than the transmission investment costs, as it is modelled and analysed in depth in Chapter 3.

Thus if the energy market prices are defined on a nodal basis, a SRMC revenue surplus will arise. The question here is what to do with the SRMC surplus: to pass it straight to the transmission owner or to allocate it among the users of the network? On the other hand, if the energy market prices are defined on a one-node basis, then a well founded cost-based method must be used to price the use of the transmission network.

The use of a value-based pricing scheme in transmission means that a competitive access market is created to discover the market value of transmission. On the other hand, the use of a cost-based pricing scheme in transmission means the definition of a regulated framework for access pricing that must be tuned with the scheme in use for the competitive energy market.

Therefore a compatible transmission pricing scheme must be tuned with the energy market scheme to work together and send opportune and right short and long term signals to the market agents regarding the use of the transmission network.

1.4 Scope and objectives of this research

The scope of this research has been focused on the analysis of the foundations of transmission access pricing in deregulated electricity markets and the study of the link between short term efficiency and long term development of the transmission network. Different realities regarding political, organisational, topological, environmental and even cultural issues have determined different regulatory schemes in application in different countries. However a common rule is the complementary characteristic of both energy market and access pricing scheme. Understanding the foundations regarding the link between short and long term issues in electricity transmission provide valuable information about the scope and limitations of different pricing schemes and serve as a guide for future developments in the area and practical implementation in countries where deregulation is still under study.

The objectives of this research can be defined as follows:

- To review the main international experiences in electricity transmission pricing and analyse its relationship with the organisation and pricing scheme in deregulated energy markets.
- To look for a link among short term and long term settlements in transmission pricing, to determine efficient options to price the use (present) and development (future) of transmission networks in a competitive energy market.
- To develop tools to simulate transmission pricing schemes, particularly short run marginal costs (SRMC), long run marginal costs (LRMC) and optimal transmission pricing derived on an economically adapted network (EAN). Then simulate, compare and evaluate those transmission pricing schemes using the tools developed.
- To obtain relevant conclusions regarding the advantages and limitations of the main pricing schemes for transmission pricing.

1.5 Main contributions of this research

This research contributes to a better understanding of the main transmission pricing schemes, revealing their advantages, disadvantages and limitations. One important contribution of this work is the development of three different models that provide a framework to analyse and evaluate different pricing schemes for transmission and the energy market. These models are as follows:

- A two bus network with linear production marginal costs and a continuous duration demand curve, implemented from the analytical formulation.
- A three bus meshed network with three demand periods and four generators, implemented using the Solver tool in MS Excel.
- A multi-node and multi-period power system model developed in C language, implemented from a previous modelling development at UMIST (Nield, S., 2000).

The main contributions of this research can be summarised as follows:

- Presentation of a joint analysis of transmission open access schemes and its interaction with the energy market to facilitate the selection of an appropriate method to price the use of transmission networks.

- Development of a unified methodology to analyse both transmission access and energy market pricing to facilitate the analysis and tests of different pricing strategies.

- Analysis of the link between short and long term issues in electricity transmission, more specifically, focus on the allocation of costs of the existing network and the development of investments to increase the capacity of the network.

- Detection of a relevant limitation of short run marginal costs (SRMC) to price the usage of the transmission network. Particularly in meshed transmission networks SRMC revenues follow Kirchhoff Voltage Law (KVL) but investments do not. Therefore there is not a perfect match between transmission SRMC revenues and investments in the optimal network, on a line per line basis. Of course, the same limitation is applicable to LRMC in the long term.

- Design and implementation of C-written routines to calculate SRMC and LRMC in a multi-node and multi-period computer programme that determines the economically adapted network of a power system.

1.6 Thesis structure

This thesis is constituted by six chapters and three appendixes whose contents are summarised below.

Chapter 1: *Main issues in transmission pricing* – This chapter presents an overview of the role of electricity transmission pricing in the new deregulated schemes in practise over the world and the main challenges regarding the search for an efficient method for transmission pricing. The objectives, scope and main contributions of this research are addressed.

Chapter 2: *Methods and experiences in transmission pricing* – This chapter describes the main objectives of a transmission pricing scheme and the main methodologies in application in deregulated energy markets. The relationship among energy market organisation, its pricing schemes, and transmission pricing are analysed in depth. Different transmission pricing experiences on deregulated energy markets around the world are addressed and analysed.

Chapter 3: *Theoretical framework for analysis of transmission* – The relationship among short term operation and long term development of the transmission network is analysed in this chapter. The main issues in electricity transmission pricing are derived through a two bus example. Energy pricing methods are simulated together with transmission pricing to check how revenues and costs are allocated among participants in the energy market.

Chapter 4: *Transmission rights, SRMC surplus and investments* – Transmission rights experiences are discussed and their application in England and Wales as ‘firm access rights’ is reviewed in detail. A pricing method based on the SRMC surplus is tested on a three bus network and on the IEEE 24 bus Reliability Test System.

Chapter 5: *Use of the concept of "economically adapted network" for transmission pricing* – A pricing method that derives transmission charges from the economically adapted network (EAN) is designed and tested in this chapter. Tests are performed on a three bus network and on the IEEE 24 bus Reliability Test System.

Chapter 6: *Conclusion* – This chapter summarises the main conclusions, achievements and contributions derived from this research, and recommends areas for future research.

Appendix A: *Nodal SRMC on a Transmission Network* – The calculation of nodal short run marginal costs (SRMC) is derived in this Appendix including two calculation methods: using generalised generation distribution factors (GGDF) and using a security constrained optimal power flow (SCOPF) representation.

Appendix B: *Simulations on a 3-Bus Network* – This Appendix shows the results of the main transmission pricing methods on a 3-bus network.

Appendix C: *Simulations on the IEEE 24-Bus Network* – This Appendix shows the results of the main transmission pricing methods on the IEEE 24-bus Reliability Test System.

CHAPTER 2

Methods and experiences in transmission pricing

Summary

This chapter describes the objectives of an electricity transmission pricing scheme and the main methodologies in use on deregulated energy markets. The relationship among the organisation of the energy market and its pricing scheme, and transmission pricing are analysed in depth. An overview of some relevant international experiences in transmission pricing are included.

2.1 Objectives of transmission pricing

There have been many discussions on how to address access pricing and what kind of scheme fits better with a competitive energy market from both short and long term perspectives (Green, R., 1997). According to those discussions the objectives of an efficient pricing scheme for electricity transmission can be summarised as follows:

- To provide short term signals regarding the transport costs imposed by participants in the energy market.
- To send location signals for investments in generation and demand.
- To signal the need for investments in the transmission network.
- To allow the recovery of the efficient costs of the existent transmission assets and the investment cost of new transmission assets.
- To be simple and transparent in determining the transmission prices.

From the regulatory perspective those issues must be covered by a methodology that allows the use of the transmission capacity in an open and non discriminatory way and avoiding any kind of market power by participants that distort the goals of a competitive market.

Among short term regulatory objectives one relevant is the way the pricing method is going to deal with transmission losses. Sometimes losses are considered as part of the energy market issues but their short term impact is closely related with the transportation of electricity using the transmission network. From that perspective losses are better dealt as part of the access market.

Among long term regulatory objectives one important issue is the way a decision making process for transmission investments will operate. Transmission investments can be market driven or centrally co-ordinated by the regulator (Hogan, W., 1999). It is perfectly possible to rely more on market forces, partly if not completely, to drive transmission expansion of the network. However, there are transmission investments like those destined to improve security of service to a large number of consumers that are very difficult to implement without regulatory support.

2.2 Electricity transmission as a business

Electricity transmission is a new business as a result of the electricity deregulation process that started in the 1980 decade. From then on several new transmission companies have been created around the world to focus on the bulk transmission of electricity and, in same cases, those companies operate the power system too. In other cases there is an independent system operator in charge of the co-ordination of generation despatch and network operation. Among the main electricity transmission companies operating in deregulated markets are Red Eléctrica de España (Spain, 1985), National Grid Company (England and Wales, 1989), Statnett (Norway, 1990), Transener (Argentina, 1992), Transelec (Chile, 1993), Transpower (New Zealand, 1993), ISA (Colombia, 1994) and Etecen and Etesur (Perú, 1995).

The main functions of electricity transmission are:

- **To link generators and consumers**
  Transmission networks provide electricity transportation from generators to consumers both located at different geographical locations on the network. Generation facilities are located close to the primary sources of energy, for instance hydroelectric power plants are located besides rivers with appreciable inflows and height differentials, coal-fired thermal plants are located close to coal mines or harbours with facilities to disembark the coal and sea water for cooling, and combined-cycle gas turbines are located close to gas pipelines city-gates. Consumers are geographically dispersed depending on the economic activity they perform, for instance residential and commercial customers are located in cities and towns, and industrial consumers are located in places where they optimise transportation costs of the different production factors.

- **To provide economies of scope**
  The interconnection of generating power plants of different characteristics (fuel type and marginal cost, capacity, technical limits, etc.) via the transmission network allows the minimisation of overall production costs, co-ordination of maintenance schedules and sharing operational reserves of capacity, following the demand curve pattern. Ancillary services can be provided by power units located far from the load centres and a market for such services is feasible to develop thanks to the transmission network.

- **To provide security of supply**
  The interconnection of several generators through the transmission network provides security of supply to consumers. Generating units and transmission facilities (lines, transformers, breakers, reactive compensation equipment, etc.) do not have a 100% availability. Generating units have forced outages due to failures or problems in the production process that mean the immediate disconnection of the unit from the

network to avoid major damages on it. Transmission facilities are subject to forced outages that mean the immediate opening of the line or the equipment that failed. The interconnection of generating units through transmission facilities minimises the impact of forced outages on consumers, increasing the availability of the power system. Deterministic security criteria such as 'N–1' have been settled in power systems for the provision of security of supply to consumers.

- **To make possible the trading of electricity**

  Today a competitive trading of electricity in the energy market is a reality thanks to the existence of transmission networks. Interconnecting electricity producers and consumers mean the perfect way to meet offer and demand to discover prices in a competitive energy market. In that sense electricity can be seen like a commodity of particular characteristics. Electricity cannot be stored and must be consumed at the same time it is produced, and also, its way from generators to consumers is not a simple straight path because of the physical interactions in the network (Kirchhoff laws). Nevertheless the basic microeconomic principles of competitive markets can be applied to create competition in the generation and retail areas.

Therefore, generators and consumers capture the benefits provided by transmission networks and hence they have to pay for the use of the network to the transmission assets owners.

The main characteristics of the transmission business from the owners point of view are:

- **It is capital intensive**

  Transmission investments are capital intensive and non continuous in time. The construction of new transmission lines, substations or the addition of new power transformers are not a daily task. They are the result of a relevant growth in demand or the connection of new power plants. If no one of those facts happen, transmission investments could require years to occur depending on the yearly rate of demand growth. Transmission assets are technologically complex, highly dedicated and some of them are irreversible (transmission lines and substations). Therefore only electricity companies with big financial shoulders can participate in this business.

- **It has long life assets**

  Most transmission assets have a long life expectancy. Transmission lines and substations typically have an economic life of 30 years or more. On the other side, capacitor banks and some high tech assets like protective, control and telecommunication equipment have a shorter life ranging between 5 and 10 years because of technological changes.

- **It has lumpiness of investments**

  Transmission capacity of lines (due to standard sizes of wires and minimum wire sections by voltage limitations) and transformation equipment have standard sizes, then it is not possible to dimension a transmission asset to match exactly to transmission demand requirements. It means some natural over-capacity of transmission assets as a result of the transmission network planning and construction process.

- **Investments require long times of construction**

  Environmental and rights of way permission add an important extra-time to the schedule for constructing new transmission assets that imply long times of construction, even longer than times involved in the construction of new generation facilities like a combined-cycle gas turbine (estimated in two and half years). Construction schedules are usually longer and more difficult when the construction of new transmission assets interfere with the operation of the existent network, or in case of upgrading of the existent transmission capacity, and some facilities must be disconnected to make possible the works.

- **It has economies of scale**

  Transmission networks have important economies of scale, meaning that the costs per MW transported are lower as higher are the MW transported. It implies that the marginal cost of expansion of the transmission network is decreasing while higher is the network capacity. This issue is especially relevant in power systems with high demand growth rates (5 to 8% per year) because of the economies achieved when the transmission network is dimensioned on a long term basis, for instance covering a ten years period.

- **It has natural monopoly characteristics**
  The presence of dedicated assets, irreversible investments and economies of scale means a perfect site for a monopolistic behaviour. The reason a monopoly exists is that other firms find it unprofitable or impossible to enter the market (Nicholson, W., 1998). Barriers to entry are therefore the source of all monopoly power.

The natural monopoly characteristic of the transmission business means that it must be regulated to mitigate any kind of market power coming from transmission asset owners. Hence wires business like electricity transmission and distribution are regulated and therefore, regulators have to address an economically efficient pricing method to determine prices for those business. Regulation must prevent network companies from overcharging users of the network and must monitor the quality of service provided. Thus, the regulator acts on behalf of network users to ensure open and non-discriminatory access to the transmission network as well as to promote the development of a competitive energy market.

2.3 Short and long run costs of transmission

The total cost function (TTC) for a certain asset of the transmission network, like a transmission line or a substation, can be written on a yearly basis as follows:

$$TTC(P) = c + a \cdot P^b + d \cdot P^2 \qquad (2\text{-}1)$$

where

- c represents the fixed annual administration, operation and maintenance costs of the transmission asset.

- $a{\cdot}P^b$ represents the annuity of the asset investment cost modelled as a non-linear function of the power flow P, where the exponent $0<b<1$ indicates the presence of economies of scale in transmission investments.
- $d{\cdot}P^2$ represents the annual cost of the transmission losses.

The average cost of transmission (TAC) can be determined from equation (2-1):

$$TAC(P) = \frac{TTC}{P} = \frac{c}{P} + a \cdot P^{b-1} + d \cdot P \qquad (2\text{-}2)$$

The marginal cost of transmission (TMC) can also be determined from equation (2-1):

$$TMC(P) = \frac{\partial TTC}{\partial P} = a \cdot b \cdot P^{b-1} + 2 \cdot d \cdot P \qquad (2\text{-}3)$$

Figure 2-1 shows graphically the curves of the total cost (TTC), average cost (TAC) and marginal cost (TMC). By definition TTC(P)= TAC(P)·P and on the other side TMC(P)·P is always lower than TTC(P) when $P<P_2$. It means that the use of the marginal cost of transmission, as seen from the purely cost point of view, as source of network revenues cannot cover the total costs of transmission and some additional charge must be added to cover the total costs. As we will see further this situation changes when the marginal revenues are calculated based on the value of transmission for the different agents in the energy market.

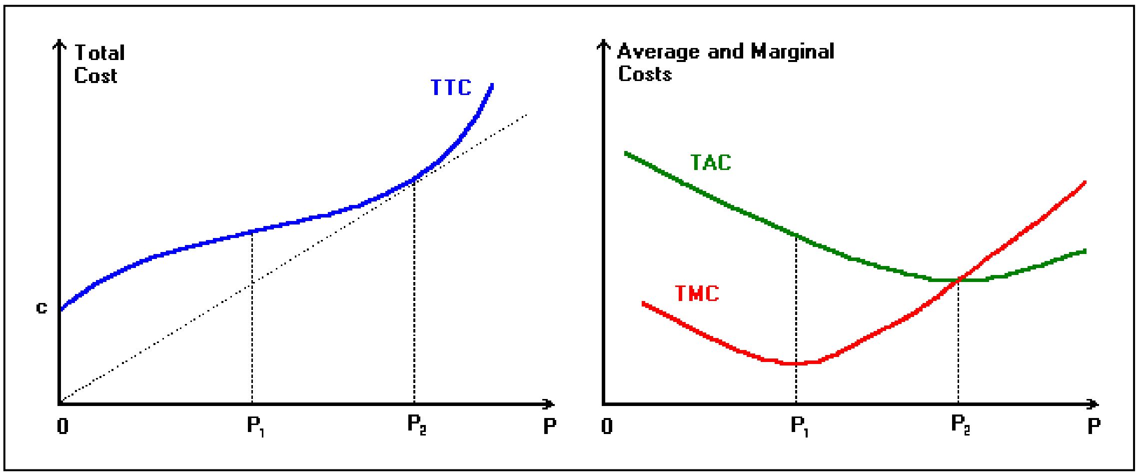


Figure 2-1 Transmission total, average and marginal costs

It is customary in economics to make a distinction between the “short run” and the “long run”. Although no very precise temporal definition can be provided for those terms, the general purpose of the distinction is to differentiate between a short period during which economic agents have only limited flexibility in their actions and a longer period that provides greater freedom (Nicholson, W., 1998). Particularly in the short run the capacity is considered fixed. Therefore, short run average and marginal costs of transmission can be defined based on equations (2-1) and (2-2), considering a fixed transmission capacity P_{max}. Thus in the short run, the marginal cost of transmission is equal to the marginal cost of losses.

In the long run capacity can be considered a variable and the long run average and marginal costs of transmission can be defined based on equations (2-1) and (2-2), considering a variable transmission capacity P. Technically, the long run total cost curve are said to be an envelope of their respective short run curves, as shown in Figure 2-1.

2.4 Methods for transmission pricing

A review of the main methods to price transmission network services around the world reveals that they can be classified in two categories: *cost-based methods* or methods driven by transmission investment costs and *value-based methods* or methods driven by generations costs.

Among *cost-based methods* we can find the following methods:

- Contract-path
- MW-mile
- Postage-stamp
- Investment cost related network pricing (ICRP)
- Area of Influence
- Tracing methods

Among *value-based methods* we find the well known short-run marginal cost (SRMC) method and the theoretical long-run marginal cost (LRMC) method.

Contract-path and MW-mile methods were developed at the end of the 80’s and used extensively mainly in the US for calculation of wheeling charges. They have been widely described in literature (Green, R., 1997).

ICRP method was developed by the National Grid Company (NGC) and it is currently used for calculation of the Transmission Network Use of System Charges (TNUoS) in England and Wales. The method is based on a transportation model to determine the optimal capacity of the network (Mutale, J., 2000).

The Area of Influence method was developed in Chile at the beginning of the 90’s and it is currently in use in Chile and Bolivia. It requires the calculation of a pro-rata to allocate the cost of the transmission assets included in the area of influence among the users that share the same common area (Rudnick, H. *et al* 1999).

Tracing methods to allocate transmission system costs over generators and demand have been extensively studied from the academic point of view but they are not in practical use (Kirschen, D. *et al* 1997, Strbac, G. *et al* 1998, Bialek, J., 1998). Nevertheless, an optional tracing method using generalised generation distribution factors (GGDF) has been used in Chile to calculate the pro-rata among users that share the same common Area of Influence (Rudnick, H., *et al* 1999).

The most widely used methods for transmission pricing in deregulated markets are the postage stamp and the SRMC methods. Additionally some pricing methods can be derived departing from the LRMC method. Therefore they are reviewed in more detail below.

2.4.1 Postage-stamp methods

This method basically allocate the total transmission network cost among users based on the peak demand (MW) or the yearly energy consumption (MWh). Transmission network costs can be ‘postage stamped’ to generation or demand or both. Postage stamp methods can be locational or not locational. Typically the sub-transmission and distribution pricing methods are a locational postage stamp pricing, where network costs are allocated to every locational demand user depending on the transmission facilities that are used to supply electricity towards a specific geographic area. On the trunk transmission system the allocation of costs is typically postage stamped in meshed networks where it is very difficult to forecast the behaviour of transmission flows.

2.4.2 LRMC method

Transmission long-run marginal cost (LRMC) is the investment and operation cost of transporting one additional MW across the network when transmission capacity can be altered. Transmission costs are usually determined using a reference network or ‘economically adapted network’ (EAN). The determination of the EAN on a power system requires a complete set of data regarding production costs of generation and investment costs of transmission, plus long term assessments about future generation costs, location of new plants, demand forecasting and its geographical distribution. Therefore the use of LRMC can be performed in systems where the regulatory authority carries out a close following up of the energy market behaviour. Additionally the regulator needs some consultation mechanisms to obtain the co-operation from the agents in the energy market regarding the definition of future scenarios and realistic investment options.

2.4.3 SRMC method

Transmission short-run marginal cost (SRMC) is the generation cost of transporting one additional MW across the network when transmission capacity is fixed. The SRMC methods are based on location specific generation costs and therefore transmission investment costs are not considered. The SRMC methods are also referred as locational marginal pricing (LMP) or spot pricing. The reason derives from the fact that in deregulated energy markets the agents bid for prices that not necessarily correspond to generation production costs. However if the energy market behaves in a competitive way finally the prices will correspond to SRMC.

Typical approaches to determine LMP in real networks include:

- Use of centrally administered security constrained optimal power flows (SCOPF) algorithms to derive LMP from bids in the energy market.
- Let the market to discover the locational value of electricity via auctions where transmission access rights are sold.

One of the best known transmission SRMC-based method is 'transmission rights' which have been developed as Fixed Transmission Rights (FTR) or Transmission Congestion Contracts (TCC) in the US. In England and Wales, Firm Access Rights (FAR) are currently under development as part of the New Electricity Trading Arrangements (NETA). These methods are described in more detail in section 3.4.

Another transmission SRMC-based method to work as an option to transmission rights are the 'flowgate rights', recently developed to deal with the externalities due to loop flows in a network (Chao, H.P. *et al* 2000).

2.5 Energy market design and transmission pricing

Competition among suppliers of any commodity requires easy access to customers. In case of electricity competition it requires that access to the transmission system by generators and consumers be managed in a non-discriminatory and equitable manner (Singh, H. *et al* 1998). This concept is well known as transmission open access. However, two basic characteristics of transmission networks must be properly handed to achieve an effective transmission open access: transmission congestion and losses.

Congestion is a consequence of network constraints characterising a finite network capacity that limits the simultaneous delivery of power from an associated set of power transactions. Losses in transmission networks corresponds to Ohmic and Corona losses that produce a difference between the total supply and demand for power in the system. Both transmission congestion and transmission losses can result in an overall increase in the total power cost delivery. These increase in cost can be much greater in case of congestion than in case of losses.

Reliable operation is a central requirement and constraint for any electricity system. Given the strong and complex interactions in electric networks, current technology with a free-flowing transmission network dictates the need for a system operator that co-ordinates use of the transmission system (Hogan, W., 1998). Control of transmission usage means control of despatch, which is the principal or only means of adjusting the use of the network. Hence, open access to the transmission network means open access to the despatch as well. This is the essential co-ordination function provided by the system operator. In the analysis of electricity markets, therefore, a key focus is the design of the interaction between transmission and despatch, both procedures and pricing, to support a competitive energy market.

2.5.1 Energy market design

There are two approaches to deal with energy market costs and constraints (i.e. transmission congestion costs). The first approach is based on a nodal pricing framework and forms the basis of the 'pool model'. The second approach is based on free market competition and it is called 'bilateral model'.

2.5.1.1 Pool-based energy markets

The pool model is motivated by the need to accommodate the special characteristics of electric power transmission networks within the electricity trading process (Singh, H. *et al* 1998). The locational aspects of the pool model are based on the theory of nodal spot pricing (Schweppe, F. *et al* 1988). This model relies on the actions of a central 'pool operator' for receiving price and quantity offers from generators, selecting the most efficient sources of supply to satisfy prevailing constraints and making financial transactions that involve payments from consumers and payments to suppliers. The prices that govern these payments are based on the bids submitted by despatched generators and an adjustment made by the 'pool operator' to reflect the locational value of suppliers in terms of their contribution to system losses and constraints. In general, these adjusted prices called 'nodal spot prices' or 'locational marginal prices', are higher at consumers locations than at generation sources locations. These locational price differentials result in a net income or surplus for the 'pool operator'. In some implementations of this model, the surplus is used to pay-off holders of financial instruments called 'firm transmission rights (FTR)' or 'transmission congestion contracts (TCC)', already described in section 2.4.3. In other implementations, the surplus is used to reduce the access charges used to recover the fixed costs of the transmission network (i.e. Chile). Another essential feature of the pool model is that all transactions made by participants in the energy market must be with the 'pool operator' and not bilaterally arranged among participants.

2.5.1.2 Bilateral energy markets

The bilateral model is motivated by the concept that free market competition is the best way to achieve competition in an electricity market. This model has also been characterised as one of that best achieves the goal of providing customers "direct access" to a supplier of choice (Singh, H. *et al* 1998). In this model suppliers and customers independently arrange power transactions with each other according to their own financial terms. Economic efficiency is promoted by customers choosing the least expensive generation options. This model might be an obvious choice if a commodity other than electricity were being traded. The special characteristics of electric power networks introduce two problems that must be addressed in this model. The first problem relates to the presence of transmission constraints which requires that there exist some form of co-ordination to maintain system security and make the most efficient use of the constrained transmission system's capacity. The second problem relates to the treatment of transmission system losses. In addition, other ancillary services must be provided to secure the transfer of power from suppliers to consumers with the security and quality standards required.

2.5.2 Energy market pricing

The main aspect to consider when a scheme of energy market prices are defined is the inclusion or not of the impact of the transmission network characteristics and their constraints over the energy prices at every location in the system or, so called, location-specific energy prices. Typical options to define electricity prices in deregulated energy markets are presented below.

- **One node pricing**

It consists in the calculation of a unique energy price or system marginal price (SMP) for the whole system at every time period (i.e. it was the pricing system used in England and Wales before NETA). The calculations do not take into account the transmission network topology and constraints, thus a one-node power system is considered to match the total supply and demand on every time period (i.e. half hour). System operators have to manage transmission congestion mechanisms to deal with transmission constraints during the day-ahead bidding process and also in real time to determine the changes on the despatch.

- **Zonal pricing**

A way to incorporate a basic representation of the transmission network consists in the definition of zones that cover sets of nodes where congestion is infrequent and possibly difficult to predict, and then every zone can be priced internally on an SMP basis (i.e. California, Norway). Congestion between zones is defined to be frequent with large impacts. Congestion management and pricing schemes between zones (inter-zonal) and within a zone (intra-zonal) are required in this case.

- **Nodal pricing**

Representing the whole topology and constraints of the transmission network and calculating nodal prices that result from the despatch are major tasks, usually afforded by 'pool system operators' (i.e. PJM, Chile). Nodal prices define the true and full opportunity cost of electricity in the short run (Hogan, W., 1998). At every node each generator and each consumer sees a single price for the period (i.e. half hour), and prices vary over the period to reflect changes on the supply and demand conditions. All the complexities of the transmission network are included in the economic despatch and calculation of the locational SRMC prices.

A whole view of pricing options in the energy market, its organisation, and the most suitable option for transmission pricing is presented in Figure 2-2. Some remarkable international experiences are included there as a reference.

	ONE NODE		ZONAL		NODAL	
Energy Market	Energy	Transmission	Energy	Transmission	Energy	Transmission
POOL	SMP +Cong. Mgt.	LRMC	Zonal LMP	Financial FTR + Post-stamp	Nodal LMP	Financial FTR + Post-stamp
	England &Wales (old) Colombia		Norway		PJM, N.York, N.England and N.Zealand Chile, Perú, Bolivia (SRMC + Tolls)	
BILATERAL	SMP for unbalances +Cong. Mgt.	LRMC	Zonal LMP for unbalances +Cong. Mgt.	Physical FTR + Post-stamp	Nodal LMP for unbalances	Physical FTR + Post-stamp
	Spain		California England & Wales (NETA)		*Nobody's land*	

Figure 2-2 Energy market organisation and pricing options

In summary, from a regulatory point of view a choice must be made among an energy market design structured as a 'pool model' or 'bilateral model', and the kind of pricing scheme, either 'one node', 'zonal' or 'nodal'. To complete the picture, a consistent transmission pricing scheme must be added to cover the transmission investment costs that were not covered by the energy market pricing scheme.

2.5.3 Energy market and system operation

System operation can be performed by an independent system operator (ISO) or by a transmission company that owns the network assets and also operates the power system (transmission owner and system operator, also known as TO/SO). The ISO are commonly found in the US (i.e. PJM Interconnection, New York Power Pool) and in some South American deregulated systems (CDEC in Chile, CAMMESA in Argentina, COES in Perú). Transmission companies acting as TO/SO are found in Europe and Australasia (NGC in England and Wales, REE in Spain and Transpower in New Zealand). Sometimes the energy market operation is performed by another kind of independent institution too (i.e. Power Exchange in California, Market Operator in Spain). Another new institution created to deal with system operation and co-ordination of transmission activities among transmission owners are the Regional Transmission Organizations (RTO), defined by the recent Federal Energy Regulatory Commission (FERC) Order No. 2000, in the US.

A whole view of the alternatives for system operation, linked to the energy market organisation and its pricing scheme, is presented in Figure 2-3. Some remarkable international experiences are included in that figure.

	ONE NODE		ZONAL		NODAL	
Energy Market	ISO	TO/SO	ISO	TO/SO	ISO	TO/SO
POOL		England & Wales (NGC, private) *OLD* Colombia (ISA, state)		Norway (Statnett, state)	Chile (CDEC) PJM (PJM Interc.) New York (NYPool)	New Zealand (Transpower, st.)
BILATERAL		Spain (REE, state)	California (Cal.ISO)	England & Wales (NGC, private) *NEW*		

Figure 2-3 Energy market organisation and system operation

2.6 International experiences

Many countries around the world have transformed their vertically integrated electricity companies and have unbundled them into generation, transmission and distribution companies. Private participation in the electricity business has been another common factor introduced in most of the cases, leaving governments only the regulatory and supervisory role. This new order has facilitated the exchange of regulatory experiences mainly on energy market models and some similar schemes can be identified. New deregulated schemes have also served as an integrated framework to allow international investors to participate in different countries as part of the globalisation process. Hence it is usual to see some well known international electricity companies buying existent assets from local companies or investing in some emerging deregulated markets. Private investment has incentives in presence of good risk rating in focus countries, competitive rates of return, simplified regulatory frameworks, transparent tariff processes and efficient allocation of resources responding to economic signals via prices.

Although generation and distribution have achieved a certain consensus regarding the use of pricing schemes, transmission pricing has not. Therefore a wide variety of particular schemes based on the main methods reviewed in section 2.4 can be found in deregulated markets around the world. Political and economical beliefs joined to cultural issues and advisory influence are the factors playing a leading role in the design of a particular pricing scheme for electricity transmission.

Chile was a pioneering country in deregulation and privatisation of the electricity sector. In September 1982 the Chilean Government dictated a new Electricity Law, DFL-1 of Ministry of Mining, that introduced the concepts of unbundling the activities of generation-transmission and distribution, open access to the transmission system and marginal cost pricing on transactions among generating companies. Following, the electricity supply industry in England and Wales was radically restructured in 1990 to allow competition initially in the generation sector of the industry and ultimately in the retail sector as well (Green, R., 1997). In March 2001 a New Electricity Trading Arrangements (NETA) were introduced initially in the energy market and ultimately in a new access market, transforming the pool-based organisation into a bilateral model (Ofgem, 2001).

After the first step given by Chile and England and Wales, in the 90's new deregulated schemes were implemented in the electricity sector of the following countries around the world:

- Latin America: Argentina, Perú, Bolivia, Colombia and Brazil
- North America: USA (PJM, California, New York and New England) and Canada (Alberta)
- Europe: Nordpool (Norway, Sweden, Finland and Denmark), Spain and Germany
- Australasia: New Zealand and Australia

Everyone has developed its own transmission pricing scheme and a review of relevant issues are described in specific literature (Green, R. *et al* 1997).

CHAPTER 3

Theoretical framework for analysis of transmission

Summary

In this chapter the theoretical framework to analyse the transmission business is developed, particularly the relationship among short term operation and long term development of the transmission network. The determination of the optimal transmission capacity of the network and the concept of an economically adapted network are discussed and analysed via an example. Energy pricing methods are simulated together with transmission pricing to determine how the revenues and costs are allocated among participants in the energy market.

3.1 Introduction

The presence of the electricity transmission network means a constraint from the energy market point of view. Transmission capacity and electricity losses in the network affect the free transportation of electricity from generators to consumers. Moreover transmission capacity is the key element that determines the economic balance between short term operational efficiency and long term optimal development of the network. A weak transmission network with demands for transportation over its capacity means high operation costs of generation due to the need for despatching more expensive generation at nodes where demand cannot be supplied with cheaper generation because of transmission constraints. In that situation local markets are created and the energy market efficiency is affected due to potential market power exercised by some agents to their own benefit. On the other side a strong transmission network with a capacity higher than maximum demands for transportation means a reduced amount of transmission constraints, a cheaper despatch of generation plants and an energy market free for competitive trading. However investment costs could be very expensive for the users. Therefore there is an economic trade off between operation costs of generation and investment costs of transmission.

3.2 Theoretical framework

A two-bus network with a continuous demand curve and price responsive energy markets at both nodes will be analysed to identify the relevant short and long term issues in electricity transmission.

Traditional models to analyse the relationship between optimal transmission capacity and transmission pricing do not consider the importance that setting the right prices have on market response. Hence there is a common belief that transmission planning and investments can be carried out by centrally co-ordinated institutions only. Certainly there are situations where market forces cannot respond to price signals and a regulated framework must support investments that are socially desirable for the whole system. However most of those situations occur because the right prices are not determined and agents work in a more competitive than co-operative manner. Nevertheless market driven investments can be feasible if the right prices for transmission are set in the energy market or in the access market. For instance nodal marginal prices permit participants in the energy market to receive a powerful signal in the short term regarding the spot value of electricity at different locations on the network. On the other side the use of transmission rights in the access market facilitates the task of sending powerful signals to participants in the energy market regarding the value of transmission on different paths in the transmission network.

3.3 Short term and energy market efficiency

The network is shown in Figure 3-1 and it considers two identical circuits that connect nodes ‘j’ and ‘k’. Every circuit has a transmission capacity equal to F. There is a generator at both nodes and it is assumed that marginal production cost of G_j is lower than cost of G_k and the demand at node ‘j’ d_j is lower than the demand at node ‘k’ d_k.

Electricity demand is represented by a yearly load duration curve d(t), shown in Figure 3-2, with a maximum demand D_1 and a minimum demand D_0, and a nodal distribution α_j and α_k.

The additional simplifying assumptions are considered:

- transmission losses, reactive power, voltage and dynamic stability issues are not included in the model.
- total generation capacities at both nodes exceed the maximum load D_1.
- generation reserve requirements are not considered.

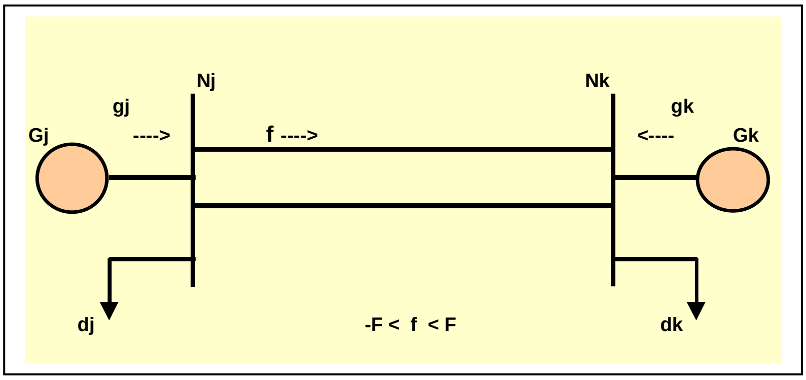
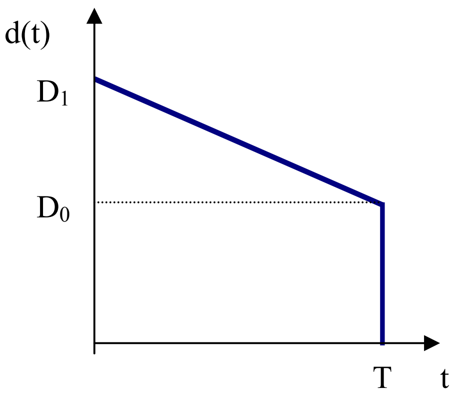


Figure 3-1 Two bus network



$d_j(t) = \alpha_j \bullet d(t)$ and $d_k(t) = \alpha_k \bullet d(t)$

$\alpha_j + \alpha_k = 1$

T= 8,760 hours

Figure 3-2 Load duration curve and nodal distribution

The production costs of the generators are represented by quadratic functions as follows:

$$C(g_j) = c_{0j} + c_{1j} \bullet g_j + c_{2j} \bullet g_j^2 \qquad g_j < G_{jM} \qquad (3\text{-}1)$$

$$C(g_k) = c_{0k} + c_{1k} \bullet g_k + c_{2k} \bullet g_k^2 \qquad g_k < G_{kM} \qquad (3\text{-}2)$$

The marginal costs of these functions are shown graphically in Figure 3-3.

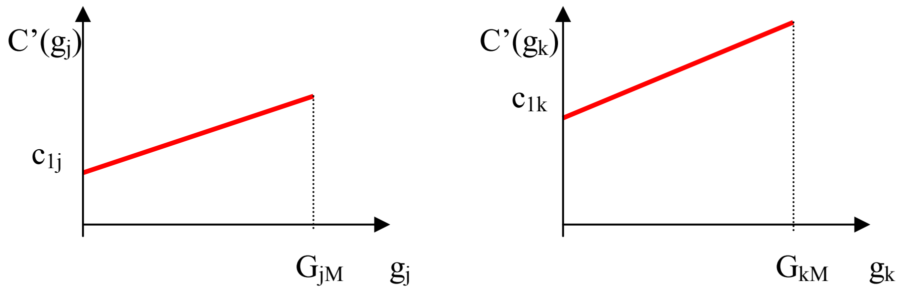


Figure 3-3 Production marginal costs of generators

In the short term the transmission capacity F is constant. So the problem to find the optimal despatch of generators, and then to obtain the power flow 'f' from node 'j' to node 'k' over a period of time T equal to a year, can be formulated through the minimisation of the total yearly operation costs (OC). Using the theory of spot pricing (Schweppe, F. *et al.*, 1988) the formulation follows:

$$Minimise: OC(g_j, g_k) = \int_0^T (c(g_j) + c(g_k))dt \qquad (3\text{-}3)$$

$$\text{s.t.: } 0 \le g_j \le G_{jM} \qquad /\mu_j \qquad (3\text{-}4)$$

$$0 \le g_k \le G_{kM} \qquad /\mu_k \qquad (3\text{-}5)$$

$$|f| \le F \qquad /\tau \qquad (3\text{-}6)$$

$$d - g_j - g_k = 0 \qquad /\lambda \qquad (3\text{-}7)$$

Constraints (3-3) and (3-4) represent the individual limits of generation of generators G_j and G_k. It is assumed that the transmission network is operated with an 'N-1' criteria in order to provide security of service to the users in case of an unexpected outage affecting one of the circuits of the line. Therefore the flow 'f' must not overcome transmission capacity F (equation 3-6). Finally equation (3-7) represents the energy balance constraint: total generation equals to total demand.

Nearby everyone of the constraints equations (3-4) to (3-7) a Lagrange multiplier has been associated. So we can rewrite the optimisation problem as a Lagrangian:

$$Z = \int_0^T \{c(g_j) + c(g_k) + \lambda \cdot (d - g_j - g_k) + \mu_j \cdot (g_j - G_{jM}) + \mu_k \cdot (g_k - G_{kM}) + \\ + \tau \cdot (|f| - F)\} dt \quad (3\text{-}8)$$

The first order conditions are:

$$\frac{\partial Z}{\partial g_j} = 0 \ ; \ \frac{\partial Z}{\partial g_k} = 0 \quad (3\text{-}9)$$

Then:

$$\frac{\partial c(g_j)}{\partial g_j} - \lambda + \mu_\mathrm{j} + \tau \frac{\partial f}{\partial g_j} = 0 \quad (3\text{-}10)$$

$$\frac{\partial c(g_k)}{\partial g_k} - \lambda + \mu_\mathrm{k} + \tau \frac{\partial f}{\partial g_k} = 0 \quad (3\text{-}11)$$

And the nodal short run marginal costs (SRMC) can be identified as:

$$\lambda_j = \frac{\partial c(g_j)}{\partial g_j} + \mu_\mathrm{j} \ \text{ and } \ \lambda_k = \frac{\partial c(g_k)}{\partial g_k} + \mu_\mathrm{k} \quad (3\text{-}12)$$

Nodal SRMC can also be written as a function of the Lagrange multipliers associated to the transmission capacity constraint τ and the system demand constraint λ, usually known as "system lambda":

$$\lambda_j = \lambda - \tau \frac{\partial f}{\partial g_j} \ \text{ and } \ \lambda_k = \lambda - \tau \frac{\partial f}{\partial g_k} \quad (3\text{-}13)$$

and transmission SRMC is:

$$\lambda_k - \lambda_j = \tau\left(\frac{\partial f}{\partial g_j} - \frac{\partial f}{\partial g_k}\right) \quad (3\text{-}14)$$

but flow 'f' can be expressed as:

$$f = \alpha_k g_j - \alpha_j g_k \quad ; \quad \alpha_k + \alpha_j = 1 \quad (3\text{-}15)$$

Then $\frac{\partial f}{\partial g_j} = \alpha_k$ and $\frac{\partial f}{\partial g_k} = -\alpha_j$ (3-16)

and

$$\lambda_k - \lambda_j = \tau \tag{3-17}$$

Equation (3-17) shows the close relationship between transmission capacity constraints and the nodal SRMC difference between both sides of a transmission line. Transmission congestion means a non zero value of τ and therefore SRMC at nodes 'j' and 'k' are different, in the absence of transmission losses. Without congestion in the network, nodal SRMC are the same everywhere and they are equal to the system lambda λ.

Therefore in the short term the market is the best way to discover the actual value of the transmission system for energy market participants, if the right SRMC prices are calculated. However SRMC prices cannot assure that transmission investment costs are really covered with the money obtained from short term balances among generators and customers. As it was shown in the short term formulation (equation 3-3), transmission capacity F was absent because it was a constant, and therefore the link between SRMC and transmission investments must be explored through a long term formulation of the optimisation problem.

3.4 Long term and network development

Complementing equation (3-3), in the long term the transmission capacity F is a variable and its optimal value can be determined. It is assumed that capacities of the generators are fixed and only transmission capacity is a relevant variable. Thereby the long term problem can be formulated through the minimisation of the total yearly operation costs and the annuity of the transmission investment cost I(F). Fixed operation and maintenance costs of transmission are assumed to be included in the I(F) function. The long term formulation of the operation plus investment costs (OIC) follows:

$$Minimise: OIC(g_{\text{j}}, g_k, F) = \int_0^T (c(g_j) + c(g_k))dt + I(F) \tag{3-18}$$

s.t.: $0 \leq g_j \leq G_{jM} \qquad /\mu_{\mathrm{j}}$ (3-19)

$0 \leq g_k \leq G_{kM} \qquad /\mu_{\mathrm{k}}$ (3-20)

$|f| \leq F \qquad /\tau$ (3-21)

$d - g_j - g_k = 0 \qquad /\lambda$ (3-22)

The first order conditions for generation are:

$$\frac{\partial Z}{\partial g_j} = 0 \ ; \ \frac{\partial Z}{\partial g_k} = 0 \tag{3-23}$$

Then,

$$\lambda_j = \lambda - \tau \frac{\partial f}{\partial g_j} \ ; \ \lambda_k = \lambda - \tau \frac{\partial f}{\partial g_k} \tag{3-24}$$

and

$$\lambda_k - \lambda_j = \tau \tag{3-25}$$

The first order condition related to transmission capacity F is:

$$\frac{\partial Z}{\partial F} = 0 \tag{3-26}$$

It means:

$$-\int_0^T \tau dt + \frac{\partial I(F)}{\partial F} = 0 \tag{3-27}$$

and then,

$$\int_0^T (\lambda_k - \lambda_j) dt = \frac{\partial I(F)}{\partial F} \tag{3-28}$$

Equation (3-28) defines the rule to determine the optimal transmission capacity between two nodes. At the optimum, the marginal cost of investment to add one additional MW of transmission capacity between two nodes must be equal to the operation marginal cost savings between those nodes, over a certain period of time.

The optimal balance between generation operation costs and transmission investment costs in the long term leads to the concept of a ‘reference network’ or ‘economically adapted network' (EAN). The EAN is defined as the transmission network that minimises the total operation plus investment costs over a certain period of time. This concept is an useful reference from the regulatory point of view and can be used for pricing purposes due to the special relationships that happen in the optimal network.

3.5 Economically adapted network (EAN) – an example

Determining the transmission network that minimises the total generation operational cost plus the transmission investment costs over a period of time means the calculation of the optimal transmission capacity on every path in the network.

In the two nodes network shown in Figure 3-1 it is assumed that the optimal transmission capacity is higher than the minimum demand at node 'k' and lower than the maximum demand at the same node ($\alpha_k \cdot D_0 < F < \alpha_k \cdot D_1$). Thus the graphs of $g_j(t)$, $g_k(t)$ and $f(t)$ are shown in Figure 3-4.

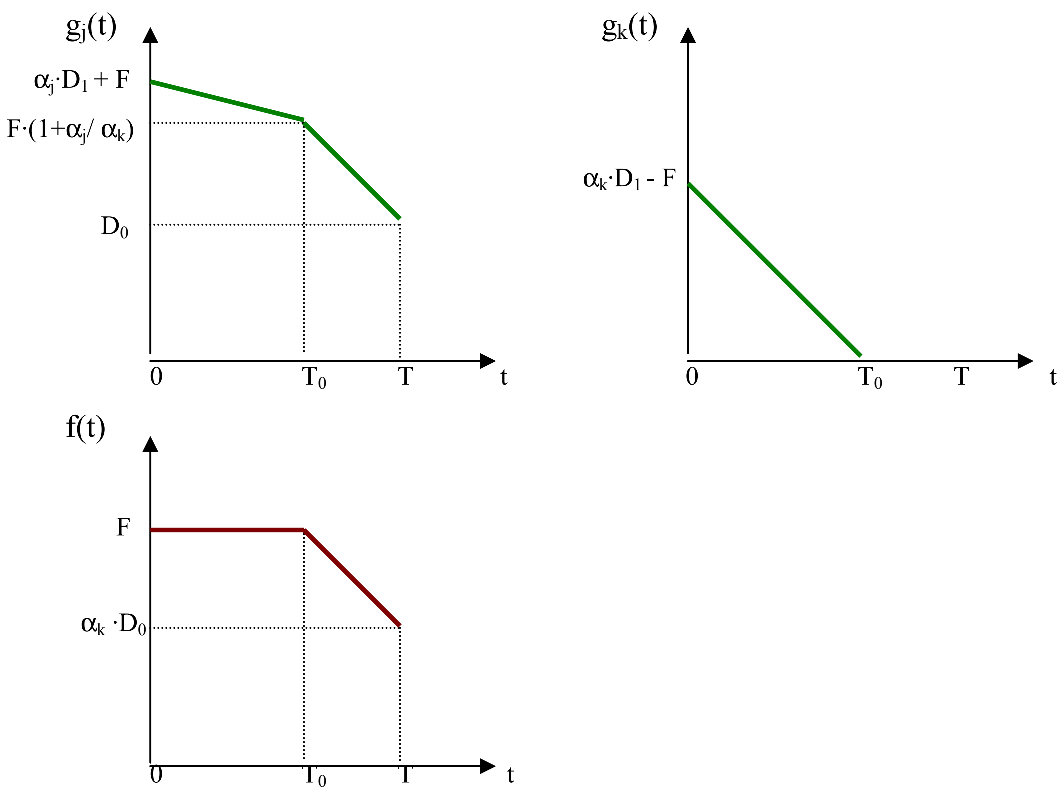


Figure 3-4 Graphs of $g_j(t)$, $g_k(t)$ and $f(t)$

During period [T_0, T], total demand d(t) is supplied by generator G_j only because it has a production cost lower than G_k. During period [0, T_0], demand at node 'k' cannot be supplied by generator G_j because the flow 'f' has reached the value of the line transmission capacity F. Therefore the more expensive generator G_k must be despatched to supply the demand at node 'k' on this period.

The optimal capacity F can be determined evaluating equation (3-28), replacing the values of marginal costs at both nodes and the annuity of transmission investment. The marginal costs can expressed as follows:

$$\lambda_j = c_{1j} + 2 \cdot c_{2j} \cdot g_j \text{ and } \lambda_k = c_{1k} + 2 \cdot c_{2k} \cdot g_k \tag{3-29}$$

$$\text{Then : } \int_0^T (\lambda_k - \lambda_j) dt = (c_{1k} - c_{1j}) \cdot T_0 + 2 \int_0^{T_0} (c_{2k} \cdot g_k - c_{2j} \cdot g_j) dt \tag{3-30}$$

with:

$$T_0 = \frac{T}{(D_1 - D_0)} \cdot (D_1 - \frac{F}{\alpha_k}) \tag{3-31}$$

Transmission investment costs have typically a non linear curve related to the capacity F, denoting economies of scale. It means that investment costs per MW transported are reduced while more MW are transported by a transmission line or power transformer. The impact of economies of scale in transmission is discussed in section 3.7.1. For the purposes of this analysis, a linear relationship between transmission investment cost and capacity will be considered:

$$I(F) = a \cdot l \cdot F \tag{3-32}$$

where '*a*' is the annuitised marginal cost of investment plus fixed operation and maintenance costs (£/MW-km-year) and '*l*' is the length of the line (km).

$$\text{Then } \frac{\partial I(F)}{\partial F} = a \cdot l \tag{3-33}$$

Replacing at both sides of equation (3-28) we obtain:

$$a \cdot l = (c_{1k} - c_{1j}) \cdot T_0 + 2 \int_0^{T_0} (c_{2k} \cdot g_k - c_{2j} \cdot g_j) dt \tag{3-34}$$

Solving analytically the integral at the right side of equation (3-34), we obtain the following second degree equation that permits the calculation of F^{opt}:

$$b_1 = (b_2 - F) \cdot (b_3 - b_4 \cdot F) \tag{3-35}$$

where:

$$b_1 = \frac{\alpha_k \cdot a \cdot l \cdot (D_1 - D_0)}{T} \tag{3-36}$$

$$b_2 = \alpha_k \cdot D_1 \tag{3-37}$$

$$b_3 = c_{1k} - c_{1j} + (c_{2k} \cdot \alpha_k - c_{2j} \cdot \alpha_j) \cdot D_1 \tag{3-38}$$

$$b_4 = c_{2k} + c_{2j} \cdot (2 + \frac{\alpha_j}{\alpha_k}) \tag{3-39}$$

The equation that calculates F^{opt} can be written as:

$$b_4 \cdot F^2 - (b_3 + b_2 \cdot b_4) \cdot F + (b_2 \cdot b_3 - b_1) = 0 \tag{3-40}$$

and the optimal transmission capacity is:

$$F^{opt} = \frac{b_3 + b_2 \cdot b_4 \pm \sqrt{(b_3 + b_2 \cdot b_4)^2 - 4 \cdot b_4 \cdot (b_2 \cdot b_3 - b_1)}}{2 \cdot b_4} \tag{3-41}$$

In the particular case of constant marginal costs at both nodes (Mutale, J., 2000), total demand concentrated at node 'k' and minimum demand equal to zero, then b_4 is equal to zero and the equation (3-40) is reduced to a first degree equation:

$$c_{2k} = c_{2j} = 0\text{; } \alpha_k = 1 \text{ and } D_0 = 0 \tag{3-42}$$

For that particular case the optimal transmission capacity is:

$$F^{opt} = D_1 \cdot (1 - \frac{a \cdot l}{(c_{1k} - c_{1j}) \cdot T}) \tag{3-43}$$

A very important issue that links short and long term at the optimal capacity point is the market value of transmission for the participants in the energy market (generators and consumers at nodes 'j' and 'k'). This value corresponds to the revenue captured by the transmission line between nodes 'j' and 'k' when the power flow transported from 'j' to 'k' is valorised with the nodal SRMC at both sides.

Then, the SRMC transmission revenue is calculated as follows:

$$SRMC\ \mathrm{tr} = \int_0^T (\lambda_k(t) - \lambda_j(t)) \cdot f(t)\, dt \tag{3-44}$$

Nodal SRMC at nodes 'j' and 'k' are shown in Figure 3-5.

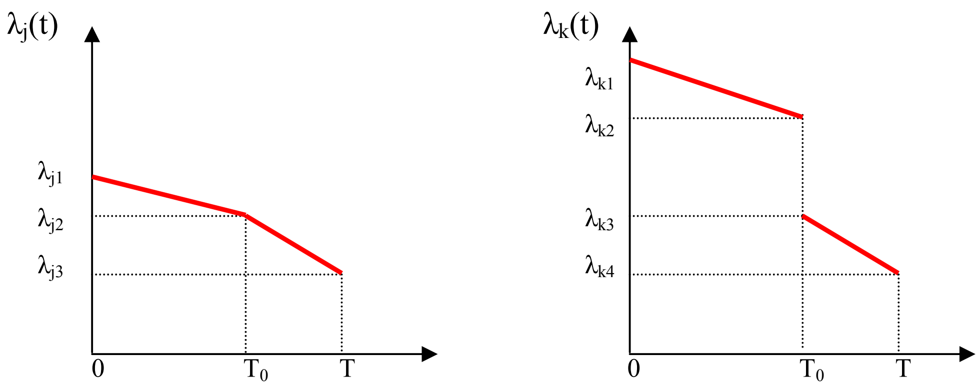


Figure 3-5 Nodal SRMC at nodes 'j' and 'k'

with:

$$\lambda_{j1} = c_{1j} + 2 \cdot c_{2j} \cdot (\alpha_j \cdot D_1 + F) \tag{3-45}$$

$$\lambda_{j2} = c_{1j} + 2 \cdot c_{2j} \cdot F \cdot (1 + \frac{\alpha_j}{\alpha_k}) \tag{3-46}$$

$$\lambda_{j3} = c_{1j} + 2 \cdot c_{2j} \cdot D_0 \tag{3-47}$$

$$\lambda_{k1} = c_{1k} + 2 \cdot c_{2k} \cdot (\alpha_k \cdot D_1 - F) \tag{3-48}$$

$$\lambda_{k2} = c_{1k} \tag{3-49}$$

$$\lambda_{k3} = \lambda_{j2} \text{ and } \lambda_{k4} = \lambda_{j3} \tag{3-50}$$

Therefore transmission SRMC is:

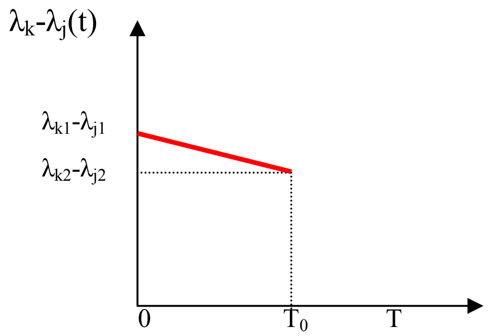


Figure 3-6 Transmission SRMC

Transmission SRMC corresponds to the nodal difference λ_k-λ_j, and its curve is shown in Figure 3-6. It can be noticed that transmission SRMC is zero in period [T_0, T] when the transmission capacity is not binding. In period [0, T_0] the transmission capacity of the line is binding and a non zero SRMC value is obtained. Valuation of equation (3-44) from this curve and considering flow *f(t)*, shown in Figure 3-4, determines the following expression for the SRMC transmission revenue:

$$SRMC\text{ tr} = (b_3 - b_4 \cdot F) \cdot F \cdot T_0 \tag{3-51}$$

where b_3 and b_4 are defined by equations (3-38) and (3-39) respectively and T_0 is defined by equation (3-31).

Equation (3-51) determines a third order relationship between transmission SRMC and capacity F, because T_0 is linearly related to F. Moreover, for the optimal transmission capacity, equation (3-35) includes the same first multiplier contained in equation (3-51). Therefore we can re-order equation (3-35) as follows:

$$(b_3 - b_4 \cdot F^{opt}) = \frac{b_1}{(b_2 - F^{opt})} \tag{3-52}$$

Replacing equation (3-52) in equation (3-51):

$$SRMC\text{ tr} = \frac{b_1 \cdot T_0}{(b_2 - F^{opt})} \cdot F^{opt} \tag{3-53}$$

Substituting the values of b_1, b_2 and T_0 in equation (3-53):

$$SRMC\text{ tr} = a \cdot l \cdot F^{opt} = I(F^{opt}) = LRMC\text{tr} \tag{3-54}$$

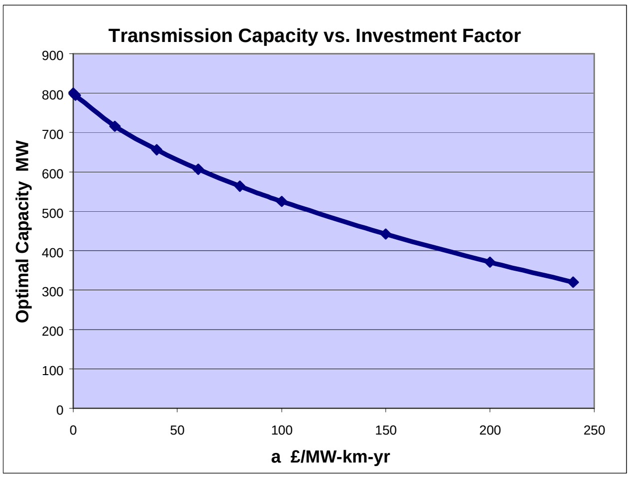
Equation (3-54) means an important conclusion: *for the optimal network transmission SRMC revenue is equal to transmission LRMC and equal to the transmission investment cost*. It must be noticed that this result is valid only when a linear relationship between transmission investment cost and capacity is considered.

For illustrative purposes, a numerical example that shows the main short and long term issues is developed. The parameters for the system shown in Figure 3-1 are:

Maximum and minimum demand: D_1=1000 MW, D_0=400 MW
Nodal demand distribution: α_j =20%, α_k =80%
Production cost of G_j: c_{1j}=20 £/MWh, c_{2j}=0.005 £/MWh^2
Production cost of G_k: c_{1k}=40 £/MWh, c_{2k}=0.025 £/MWh^2
Generation limits: G_{jM}=G_{kM}=1000 MW
Annuitised investment factor: *a*= 60 £/MW-km-year
Length of the line: *l*= 1,000 km.

The optimal transmission capacity F^{opt} , calculated by equation (3-41), is equal to 607 MW and T_0 is 3,528 hours. The second solution of equation (3-40) is discarded because it resulted numerically higher than maximum demand. A sensitivity analysis to show the impact of the main cost variables (investment and production) on the optimal transmission capacity is presented in Figure 3-7.

a £/MW-km	F MW
0	800
1	795
20	716
40	656
60	**607**
80	564
100	525
150	442
200	371
240	320



c_{1k} £/MWh	F MW
20	331
25	422
30	499
35	560
40	**607**
45	642
50	667
55	687
60	702
70	723
90	747
120	764

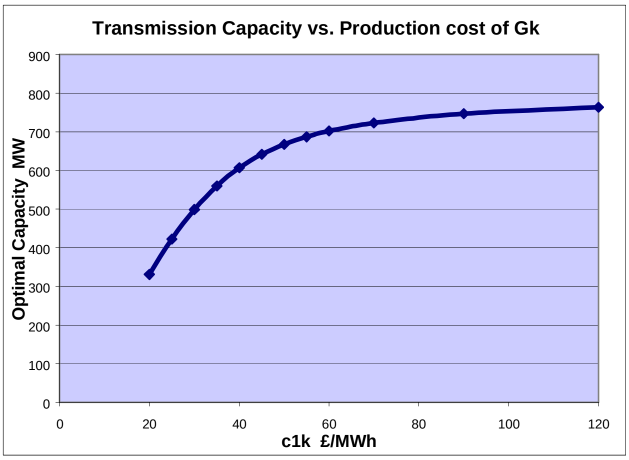


Figure 3-7 Sensitivity analysis on optimal transmission capacity (base case is remarked with an arrow)

From Figure 3-7 it can be noticed that there is a trade off between the optimal transmission capacity and the transmission investment cost. While lower the investment factor is, a higher optimal transmission capacity is obtained, keeping the same SRMC between the extremes of the line. On the other side, there is a straight relationship between optimal transmission capacity and the SRMC difference at both extremes of the line, keeping a constant investment factor. While higher the SRMC difference between both extremes of a transmission line, higher the optimal transmission capacity.

The yearly duration curves of the total demand, transmission and despatch of G_j and G_k , for a transmission capacity of 607 MW, are shown in Figure 3-8. The curves follow the same patterns already shown in Figures 3-2 and 3-4.

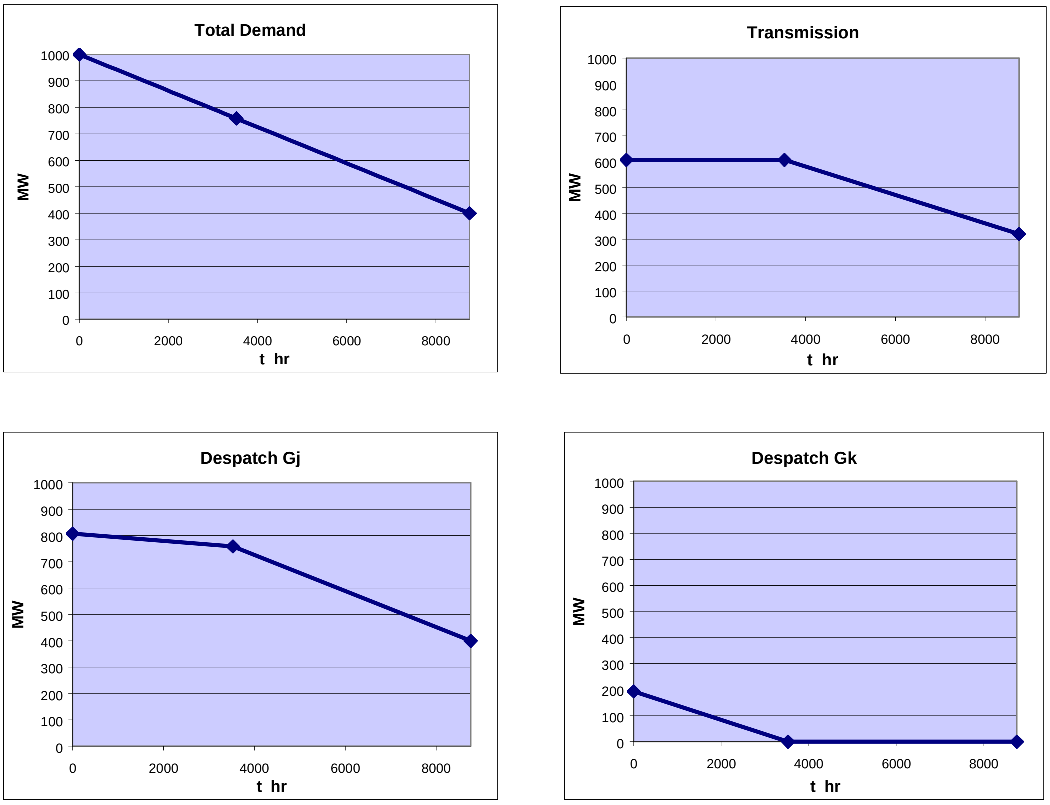


Figure 3-8 Duration curves of demand, transmission and generators despatch

Evaluating equation (3-44) with the optimal transmission capacity and the SRMC limits provided by equations (3-45) to (3-49), so the SRMC transmission revenue is equal to £36.4 Millions. The annuity of the investment cost for the optimal transmission capacity, calculated from equation (3-32), is equal to £36.4 Millions too. It was an expected result according to equation (3-54).

The economically adapted network is optimally congested because generation despatch costs and transmission investment costs are optimally balanced. Usually the despatch cost without taking into account transmission constraints is called Merit-order generation cost (MOG), and the additional cost of generation due to transmission constraints is called Out-of-merit generation cost (OMG) or Uplift. MOG and OMG costs can be calculated as follows:

$$MOG\cos t = \int_{0}^{T} c_j(d(t))dt \tag{3-55}$$

$$OMG\cos t = \int_{0}^{T_0} (c_k(g_k(t)) - c_j(g_k(t)))dt \tag{3-56}$$

Calculated values for operating cost, transmission investment cost, total cost, merit-order generation cost and out-of-merit generation cost for several values of transmission capacities are presented in Table 3-1.

Table 3-1 Operating, investment and total cost for several transmission capacities

Capacity (MW)	Operating cost (M£)	Investm. cost (M£)	Total cost (M£)	MOG cost (M£)	OMG cost (M£)
320	190.8	19.2	210.0	145.4	45.4
400	174.1	24.0	198.1	145.4	28.7
500	159.6	30.0	189.6	145.4	14.2
600	150.8	36.0	186.8	145.4	5.4
607	**150.4**	**36.4**	**186.8**	**145.4**	**5.0**
700	146.5	42.0	188.5	145.4	1.1
800	145.4	48.0	193.4	145.4	0.0
900	145.4	54.0	199.4	145.4	0.0
1000	145.4	60.0	205.4	145.4	0.0

The minimum total cost is obtained for the optimal capacity equal to 607 MW, as it is shown in Figure 3-9.

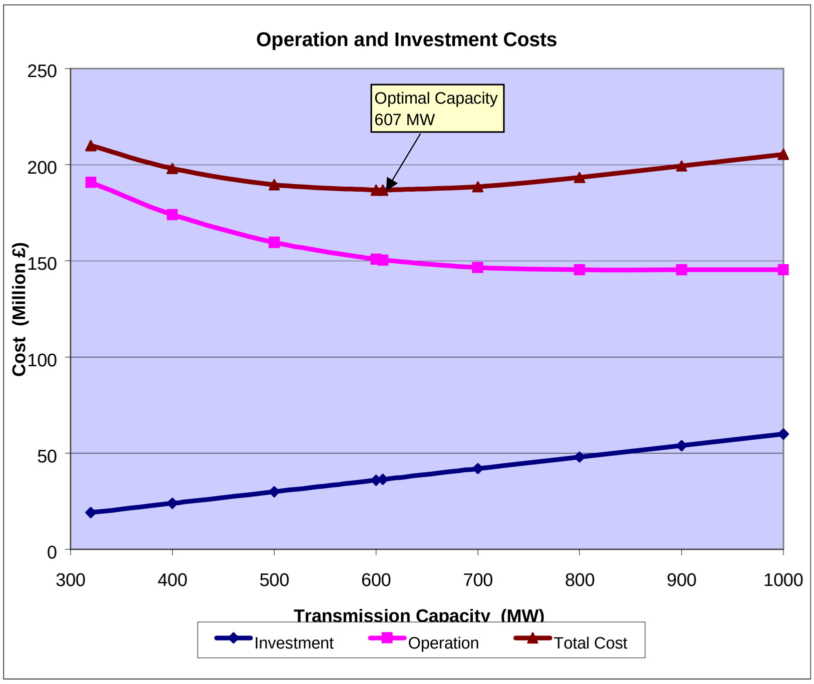


Figure 3-9 Operation, investment and total cost for several transmission capacities

Transmission investment cost always increases when a higher value of transmission capacity is considered. Nevertheless the users of the network do not perceive that transmission is so important when higher values of capacities are considered. The value of transmission for users of the network is higher while less capacity is available for them. The value of a good is strictly related to its scarcity value and while more scarce is transmission more valued it is in the energy market. In Figure 3-9 it is shown that for lower values of transmission capacity, operation cost is bigger and therefore some users must afford this big cost. The measure of the value of transmission for the energy market participants is the SRMC transmission revenue, also known as 'transmission congestion cost'.

From the transmission pricing point of view the concept of value of transmission is directly related to the SRMC transmission revenue and therefore it is associated to short term generation costs. On the other side the concept of cost of transmission is related to transmission investment costs and therefore with long term transmission costs that the transmission assets owners must recover if they want to continue investing for developing the network. The relationship between the value and cost of transmission is presented in Figure 3-10, where the SRMC transmission revenue (transmission congestion cost) and transmission investment cost (assumed linear) are shown.

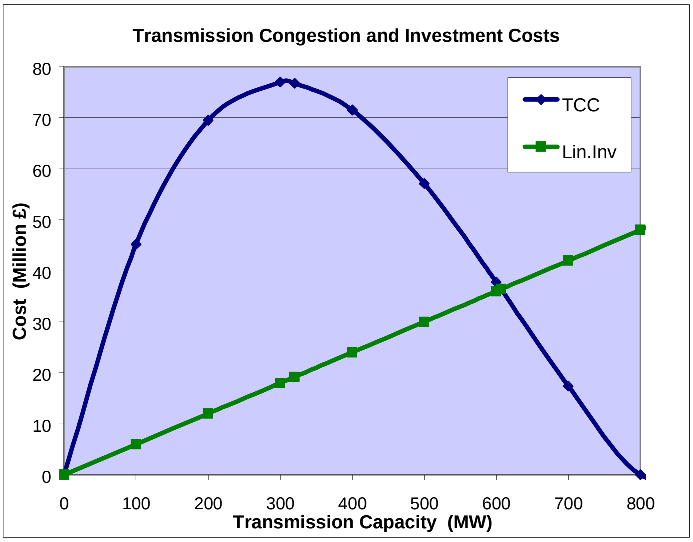


Figure 3-10 Value vs. cost of transmission

The relationship between out-of-merit generation cost and transmission congestion cost is shown in Figure 3-11.

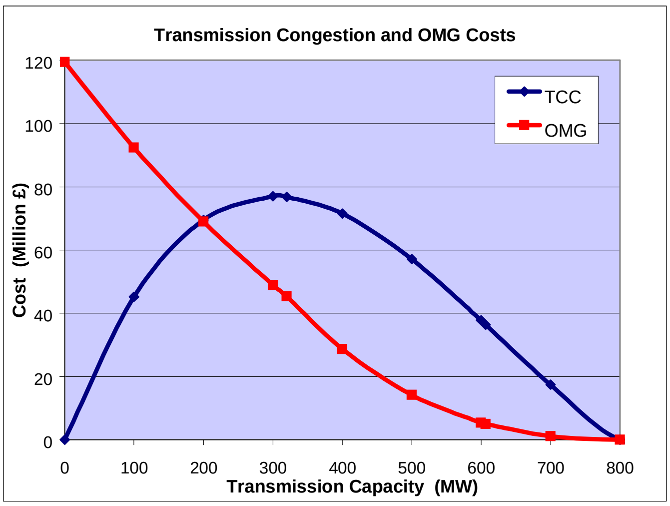


Figure 3-11 OMG cost vs. transmission congestion cost

A more detailed analysis of the transmission SRMC revenue reveals that the value of transmission increases while transmission capacity decreases from its optimal value. It means that a pricing method based on SRMC, like transmission rights, will bring more money than necessary to just cover the transmission investment cost of the network when capacities are under the optimal value. Reducing the value of transmission capacity there is a value from which the value of transmission begins to decrease towards zero, for a capacity equals to zero. This situation is produced by the way the transmission SRMC is defined, as a product of the transmission SRMC price by the power flow through the line. At the other side, for transmission capacities over the optimal value, transmission SRMC decreases faster towards zero for slight over-capacities. The impact of over-capacity, measured as the percentage in excess above optimal transmission capacity, on the SRMC transmission revenue is shown in Figure 4-12.

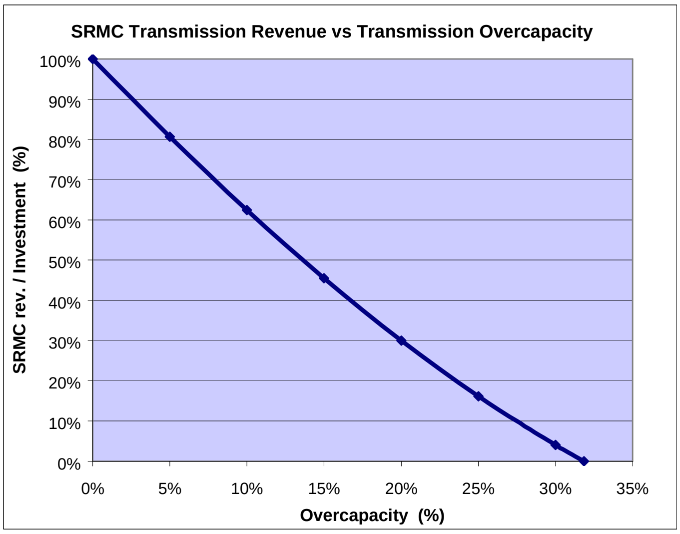


Figure 3-12 Impact of over-capacities on SRMC transmission revenue

Therefore, from the energy market point of view, transmission have a null value for over-capacities above 32% in this example. However the benefits of reduced operating costs and economies of scope have already been captured by the energy market participants but not recognised by the transmission SRMC. This conclusion is very important when a new transmission pricing method is under design by a regulatory authority because an SRMC-based pricing method could be a very bad choice depending on the robustness or weakness of the network capacity under study. Particularly in developing power systems it is usual that transmission capacity is higher than present demands for transportation and then SRMC revenues cannot cover the total investment costs of the network. Additionally, by security of service reasons it is usual that transmission networks have some back up capacity which will not be paid by the SRMC revenue either. In summary, an SRMC-based pricing method for transmission does not have any relationship with transmission investment costs, except for the economically adapted network when investment costs are assumed linear.

3.6 Energy market and transmission pricing

The application of the SRMC (nodal) and SMP (one node) pricing methods, presented in section 2.5.2, in the energy market of the network shown in Figure 3-1 is analysed. The economic despatch is the same for both methods and it corresponds to the optimal solution of the short term problem (equation 3-3).

Table 3-2 Operational analysis of the network, considering a transmission capacity equal to the optimal (607 MW)

Optimal despatch (MWh)			
Generation	[0, To]	[To, T]	Total
Gj	2,760.7	3,030.4	5,791.0
Gk	341.0	0.0	341.0
Total G	3,101.6	3,030.4	6,132.0
Demand	[0, To]	[To, T]	Total
Dj	620.3	606.1	1,226.4
Dk	2,481.3	2,424.3	4,905.6
Total D	3,101.6	3,030.4	6,132.0
Transmission	[0, To]	[To, T]	Total
Tjk	2,140.3	2,424.3	4,564.6

Table 3-3 shows the total cost of operation and transmission investment of the network. The optimal annuity of transmission investment cost is equal to £36.4 Millions.

Table 3-3 Total operational and network costs considering a transmission capacity equal to the optimal (607 MW)

Operational Costs (Thousand £)			
	[0, To]	[To, T]	Total
Gj	66,018	69,663	135,681
Gk	14,738	0	14,738
Total Op.Costs	80,756	69,663	150,419
MOG cost	75,753	69,663	145,416
OMG cost	5,003	0	5,003
Transmission Investments (Thousand £)			
Annuity Investment Cost			36,402
Total Costs (Thousand £/yr)			186,820

3.6.1 Energy market balance using nodal SRMC pricing

The application of SRMC pricing means that every transaction by generators and consumers is valued at the respective node at any time with the nodal SRMC. For the optimal transmission capacity the balance follows in Table 3-4.

Table 3-4 Energy market balance with SRMC pricing

SRMC Revenues (Thousand £)			
Generation	[0, To]	[To, T]	Total
Gj	76,823	78,718	155,541
Gk	15,836	0	15,836
Total G	92,660	78,718	171,378
Demand	[0, To]	[To, T]	Total
Dj	-17,268	-15,744	-33,011
Dk	-111,793	-62,975	-174,768
Total D	-129,061	-78,718	-207,779
D-G	-36,402	0	-36,402
Transmission	[0, To]	[To, T]	Total
Tjk	36,402	0	36,402

Using SRMC pricing demand pays more than generation and the SRMC surplus is the transmission SRMC revenue. The transmission SRMC revenue is equal to the annuity of the investment cost for the optimal capacity (compare figures in Table 3-3 and 3-4). From the regulatory point of view it is important to be careful with the application of SRMC pricing because the existence of an SRMC surplus does not necessary mean that it must be allocated to the transmission assets owners. Looking at Figure 3-10 it is evident that there could be a perverse incentive for owners to cause congestion to increase the transmission SRMC revenue over the value of the assets if the transmission business is considered a monopoly. This effect can be mitigated if the SRMC surplus has a neutral effect for the transmission owners (TO). For instance if the SRMC surplus is allocated to the energy market participants via financial transmission rights (like in the US' PJM or New York Pool) or if it is allocated to the TO as part of the transmission revenue but annually re-liquidated against the maximum revenue allowed to transmission (like in Chile).

Nodal SRMC were calculated using equations (3-45) to (3-50) and Table 3-5 shows the average values at every period and for the whole period [0, T].

Table 3-5 Average nodal SRMC (£/MWh)

SRMC	[0, To]	[To, T]	[0, T]
Node j	27.8	25.8	26.6
Node k	44.8	25.8	33.5
Line j-k	17.0	0.0	6.8

3.6.2 Energy market balance using SMP

The application of a system marginal pricing (SMP) means that every transaction by generators and consumers are valued at any time with a unique price equal to SMP, with independence of the location of generators and consumers on the network. This pricing system was in use in England and Wales from 1990 to 2001, when it was replaced by the New Electricity Trading Arrangements (NETA).

Using SMP requires the previous determination of the unconstrained optimal generation schedule without consideration of the transmission constraints. The unconstrained despatch is performed only by generator G_j to supply the total demand, therefore the SMP corresponds to the marginal cost of generator G_j. Figure 3-13 shows the SMP curve and Table 3-6 presents the average values at every period and for the whole period [0, T].

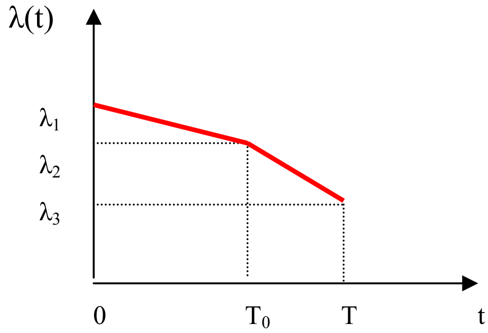


Figure 3-13 System marginal price (SMP)

with:

$$\lambda_1 = c_{1j} + 2 \cdot c_{2j} \cdot D_1 \tag{3-57}$$

$$\lambda_2 = c_{1j} + 2 \cdot c_{2j} \cdot F \cdot (1 + \frac{\alpha_j}{\alpha_k}) = \lambda_{j2} \tag{3-58}$$

$$\lambda_3 = c_{1j} + 2 \cdot c_{2j} \cdot D_0 = \lambda_{j3} \tag{3-59}$$

Table 3-6 Average SMP (£/MWh)

	[0, To]	[To, T]	[0, T]
SMP	28.8	25.8	27.0

Afterward it is necessary to determine the constrained optimal generation schedule in order to perform the despatch considering the network constraints. The difference between the constrained and unconstrained operational costs is equal to the out-of-merit generation cost (OMG) or uplift.

Table 3-7 presents the unconstrained and constrained despatch and the operational costs. The constrained optimal despatch is of course equal to the despatch shown in Table 3-2 and the operational costs shown in Table 3-3.

Table 3-7 Despatch and operational costs with SMP

Despatch

Unconstrained (MWh)

Generation	[0, To]	[To, T]	Total
Gj	3,101.6	3,030.4	6,132.0
Gk	0.0	0.0	0.0
Total G	3,101.6	3,030.4	6,132.0

Constrained (MWh)

Generation	[0, To]	[To, T]	Total
Gj	2,760.7	3,030.4	5,791.0
Gk	341.0	0.0	341.0
Total G	3,101.6	3,030.4	6,132.0

Operational Costs

Unconstrained (Thousand £)

	[0, To]	[To, T]	Total
Gj	75,753	69,663	145,416
Gk	0	0	0
Total Op.Costs	75,753	69,663	145,416

Constrained (Thousand £)

	[0, To]	[To, T]	Total
Gj	66,018	69,663	135,681
Gk	14,738	0	14,738
Total Op.Costs	80,756	69,663	150,419
Uplift	5,003	0	5,003

As a result of the transmission constraints, generator G_j is prevented from fully accessing the energy market and it must be compensated by the loss of profit. Therefore a constrained off payment is allocated to G_j and it is equal to the price margin between the SMP and the operation cost C_j multiplied by the avoided despatch (unconstrained despatch minus constrained despatch).

Constrained off payment to $G_j = (SMP - C_j) \cdot (G_j^{un} - G_j^{co})$ (3-60)

$$= \int_0^{To} (\lambda_j(t) \cdot (g_j^{un} - g_j^{co}) - c_j(g_j^{un}) + c_j(g_j^{co}))dt \qquad (3\text{-}61)$$

On the other side, generator G_k is called upon and a constrained on payment must be allocated to G_k. That payment is equal to the additional operation cost C_k incurred by generator G_k over the SMP, multiplied by the additional despatch (constrained despatch minus unconstrained despatch).

Constrained on payment to $G_k = (C_k - SMP) \cdot (G_k^{co} - G_k^{un})$ (3-62)

$$= \int_0^{To} (c_k(g_k^{co}) - c_k(g_k^{un}) - \lambda_j(t) \cdot (g_k^{co} - g_k^{un}))dt \qquad (3\text{-}63)$$

Payments to generators using SMP are adjusted using equations (3-61) and (3-62). The uplift is equal to the sum of the constrained off and on payments and it is paid by the demand in proportion to its size. Table 3-8 shows the SMP revenues.

Table 3-8 SMP revenues

SMP Revenues (Thousand £)

Generation		[0, To]	[To, T]	Total
Gj		79,519	78,718	158,237
Gk		9,955	0	9,955
Total G		89,474	78,718	168,192

Constrained payments				Gen.Total
Gj	OFF	220		158,457
Gk	ON	4,783		14,738
Total G		5,003		173,195

Demand		[0, To]	[To, T]	Total
Dj		-17,895	-15,744	-33,638
Dk		-71,579	-62,975	-134,554
Total D		-89,474	-78,718	-168,192

Constrained charges				Dem.Total
Dj	20%	-1,001		-34,639
Dk	80%	-4,002		-138,556
Total D		-5,003		-173,195

3.6.3 Impact of transmission in the energy market

As an important difference with SRMC pricing, in this case SMP revenues of generators are equal to payments by demand. Particularly in the example demand D_k pays much more with SRMC pricing in comparison with SMP. On the other side generator G_k receives higher revenues with SRMC due to the higher market value of energy at node 'k' when the network is constrained. Therefore, using SMP it can be noticed that the allocation of the uplift among demands D_j and D_k is questionable because a proportional distribution not necessary reflect an efficient cost allocation. Comparing SRMC and SMP revenues it can be inferred that mainly demand D_k holds the cost of transmission although this conclusion cannot be generalised because it depends on how the energy market prices at nodes 'j' and 'k' react under constrained conditions. In the example, the energy market prices at nodes 'j' and 'k' are determined by the production costs of generators G_j and G_k and the offer-demand balance at every node. Figure 3-14 shows a sensitivity analysis performed by changing transmission capacity down and up from the optimal capacity (607 MW) to observe the impact on nodal prices.

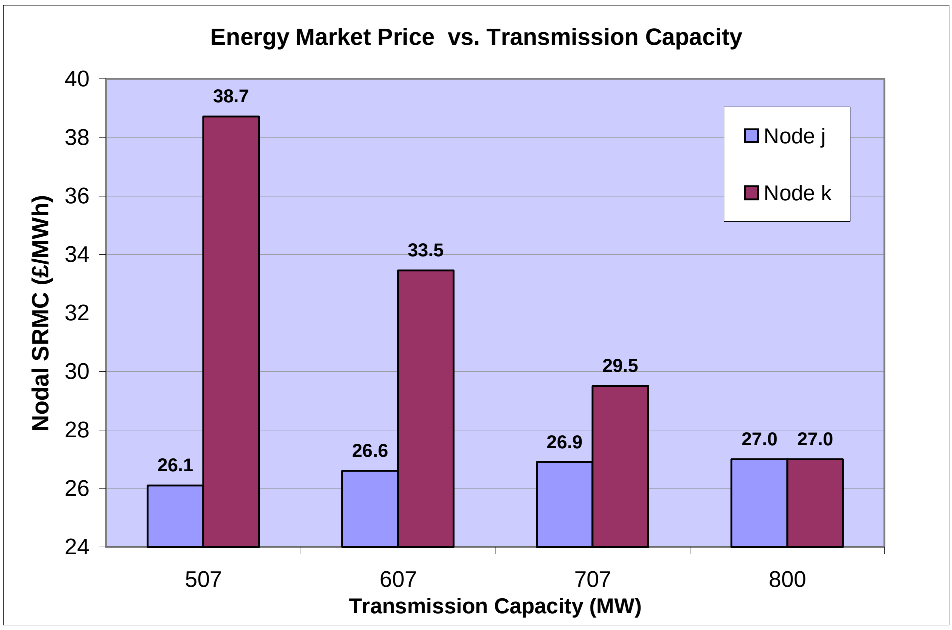


Figure 3-14 Impact of transmission capacity on the energy market prices

For lower values of the transmission capacity the impact on the energy market prices at nodes ‘j’ and ‘k’ is higher due to the need to despatch generator G_k to supply the demand at node ‘k’ in order to respect the transmission constraint. That higher difference of prices between both nodes means higher transmission congestion costs (as seen in Figure 3-10). At the extreme, for a null transmission capacity the energy markets at nodes ‘j’ and ‘k’ are economically decoupled. On the other side, for a transmission capacity equal to the maximum demand at node ‘k’ (800 MW), there is no transmission constraint and the energy market prices are equal to the SMP (27.0 £/MWh) at both nodes.

For the optimal transmission capacity, locational marginal prices are equal to LRMC and they cover the optimal investment cost of the network. Thus, an optimal strategy to determine transmission prices can be derived from the economically adapted network. A set of transmission prices that contain the full interaction among optimal transmission investment and the energy market behaviour correspond to the difference between nodal prices and SMP. Figure 3-15 shows nodal prices and SMP for the optimal transmission capacity (607 MW) and from then a set of annual transmission prices is determined for node ‘k’ equal to 6.5 £/MWh and for node ‘j’ equal to –0.4 £/MWh.

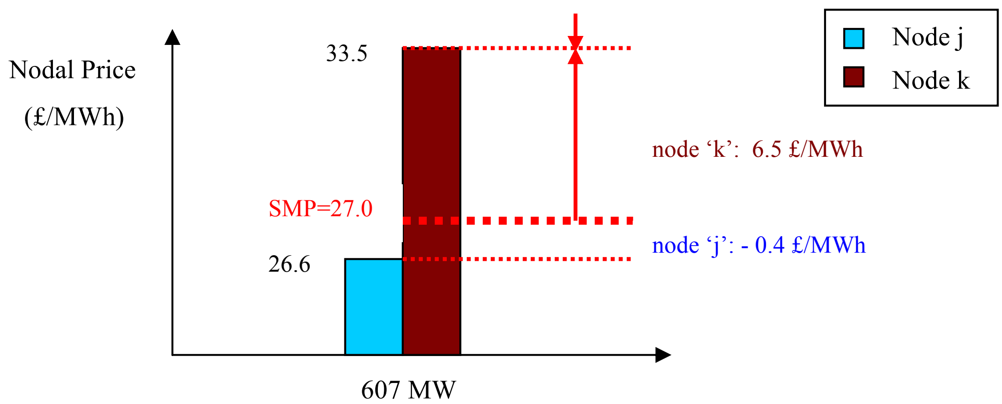


Figure 3-15 Transmission prices and energy market prices

Transmission prices showed in Figure 3-15 mean that demand at node ‘k’ must pay an annual charge of 6.5 £/MWh and generation is paid the same price. At node ‘j’ demand must pay a charge of –0.4 £/MWh (so demand is paid 0.4 £/MWh) and generation is paid the same price (so generation must pay 0.4 £/MWh). Therefore, in this example generator G_j and demand D_k must afford the cost of the transmission network.

A link between short and long term issues in electricity transmission pricing can be derived from the previous example. Figure 3-16 shows a two node network that links the energy markets 'A' and 'B'. A set of generators G_a and G_b supply the demand D_a and D_b at nodes 'A' and 'B' respectively. In the short term the transmission capacity F is fixed and the power flow 'f' can be considered as a demand (D) at market 'A' and as an offer (O) at node 'B'. Then nodal prices (P_a and P_b) are determined by the intersection of the offer and demand curves at every market.

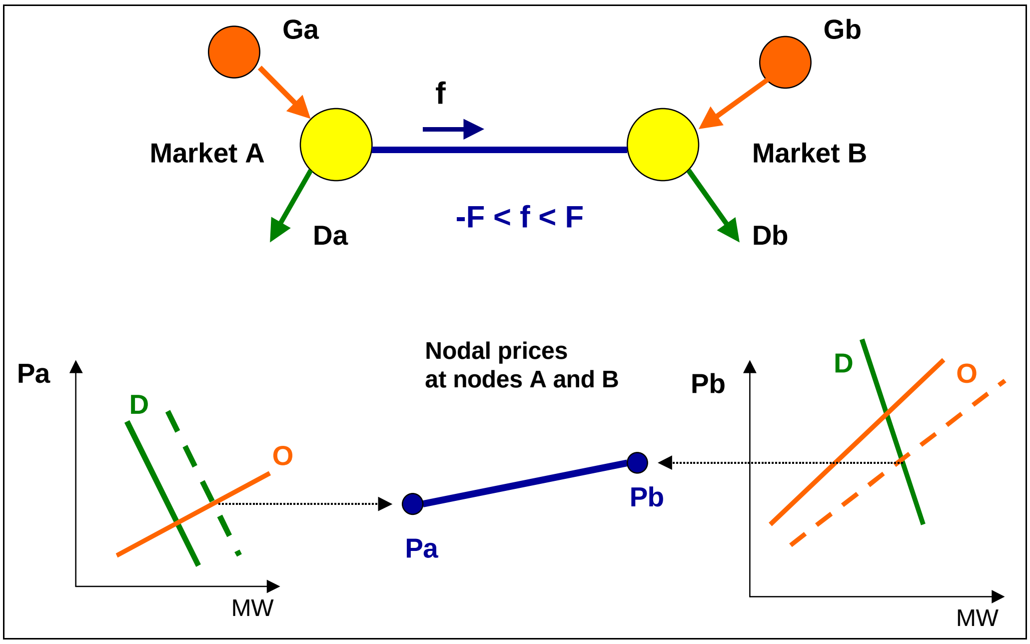


Figure 3-16 Energy market and transmission prices in the short term

In the long term the transmission capacity F can be considered a variable and depending on its value the energy market equilibrium at nodes 'A' and 'B' is changed. Figure 3-17 shows the impact of two different values of the transmission capacity F on nodal prices P_a and P_b. If we assume that the capacity of the existent network is F_1 and the economically adapted network has an optimal capacity equal to F_2, then a set of transmission prices that combine investment cost and energy market elements can be determined.

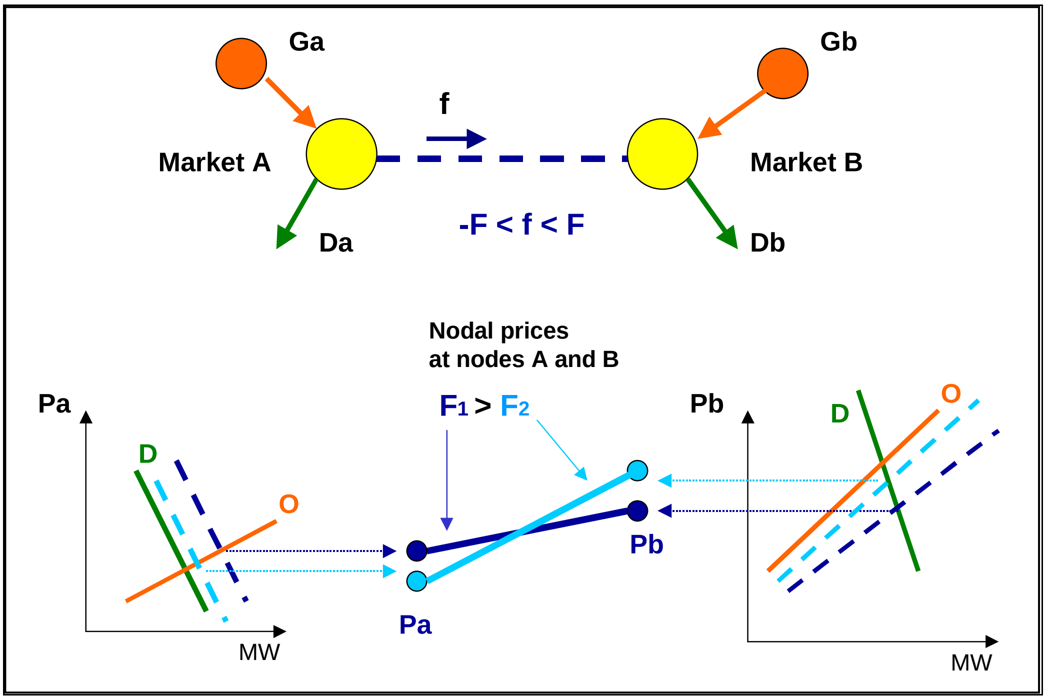


Figure 3-17 Energy market and transmission prices in the long term

In spite of the economic advantages of this theoretical method for transmission pricing, it fails in meshed networks due to additional physical constraint created by the Kirchhoff Voltage Law (KVL) as it will be explained in Chapter 4. Anyway the analysis of the economic concepts provide a solid base for designing an efficient pricing method that links the energy market and the access to the network.

In conclusion, SMP requires a transmission pricing method that covers the full cost of the transmission network. On the other side, SRMC has two possible options: first, to add on top a transmission pricing method to cover the difference between the investment cost and the SRMC surplus or second, to send back the SRMC surplus to the energy market participants (for instance via FTR) and to set a transmission pricing method that covers the full cost of the transmission network. Figure 3-18 presents graphically the typical situation in the majority of power systems around the world, with over-capacity in the network. The application of SRMC produces a surplus that is not enough to cover the investment costs of the network (for example in the Chilean system the SRMC surplus covers close to 20% of the investment costs of the existent network).

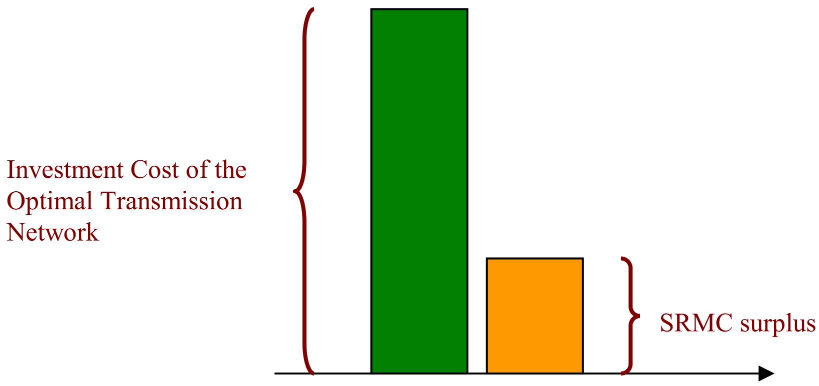


Figure 3-18 Investment cost and SRMC surplus

The question is finding an adequate mix between energy market pricing and transmission access pricing. Among the methods that present the best match with the pricing objectives the options are:

- <u>SRMC/LRMC:</u> A value based method like SRMC works very well in the energy market but it is not related to transmission investments. Thus the additional information regarding investments provided by LRMC could be the base for a strong pricing method. These methods will be analysed in Chapter 4.
- <u>Optimal transmission prices derived from the EAN:</u> A cost based method derived from the economically adapted network (EAN) has the advantage to depart from the optimal investment cost of the network and the challenge consists in finding the best way to allocate the costs among generators and consumers. This method will be analysed in Chapter 5.

The postage stamp method has not been considered in the analysis to come because it is a second best regulatory solution that brings simplicity to the calculation of transmission access charges but it does not have an economic foundation.

3.7 Other transmission pricing issues

3.7.1 Economies of scale in transmission

The economies of scale were mentioned in section 2.2 among the main characteristics of the transmission business from the owners point of view. In developing countries the transmission system is still under development and therefore the determination of the economically adapted network must take into account a long term solution that minimises the total investment plus operation cost, considering realistic scenarios concerning the development of the energy market.

Transmission costs have important economies of scale and they are reflected in the investment cost of transmission lines, transformers and substations, meaning that the transmission cost per MW is lower for higher volumes of MW transported. Table 3-9 presents the investment costs of double circuit transmission lines based on Chilean figures. Investment costs include the construction of the transmission line, rights of way and the associated equipment in substations.

Table 3-9 Investment costs for transmission lines

Line characteristics			Investment costs			Modelisation		Modelisation	
Voltage	Length	Capacity	Line	Substation	Total	Linear	Non Linear	Error (%)	
kV	km	MW	TUS$/km	TUS$/km	TUS$/km	TUS$/km	TUS$/km	Linear	Non Linear
13	10	8	23	24	47	3.6	42.0	-92%	-11%
66	50	30	50	20	70	13.5	75.9	-81%	8%
110	100	90	100	14	114	40.5	124.0	-64%	9%
220	200	300	180	22	202	135.0	212.5	-33%	5%
330	300	700	300	22	322	315.0	310.4	-2%	-4%
500	400	1200	400	22	422	540.0	395.1	28%	-6%

In Table 3-9 the investment costs per kilometer *I(F)* are modelled by a linear curve and a non linear curve (exponential) as a function of the transmission capacity F, whose parameters were obtained by a regression analysis.

Linear curve: $I(F)/km = 0.45 \cdot F$ (Thousand US$/km)

Non linear curve: $I(F)/km = 16.56 \cdot F^{0.4474}$ (Thousand US$/km)

Figure 3-19 shows a better adjustment between the total transmission investment cost curve and the non linear curve that reflects the economies of scale characteristic (capacity exponent lower than 1). The error is also lower with the non linear model compared to the linear model, as indicated in Table 3-9.

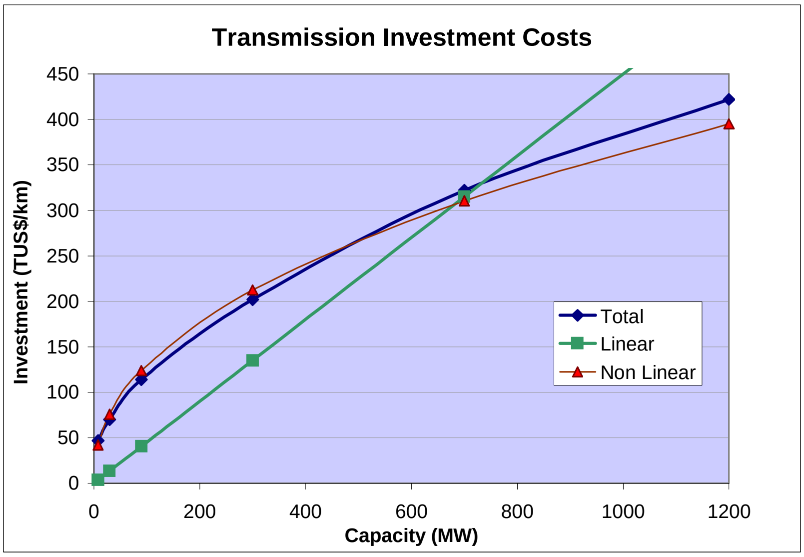


Figure 3-19 Modelling of the transmission investment costs

In summary, a linear modelling of the transmission investment costs does not exactly reflect a real characteristic of the transmission network. Nevertheless, a linear model provides a reasonable foundation to build the transmission pricing theory. In that sense the economies of scale are not a relevant issue in the design of a transmission pricing policy but they must be considered when the economically adapted network is determined.

The impact of economies of scale in the determination of the economically adapted network can be tested through the same example of section 3.5 but considering a non linear investment curve. The optimal transmission capacity is determined by solving numerically the equations 3-34 and 3-35, considering the following non linear investment curve, instead a linear one:

$I(F)/km = 2{,}070.25 \cdot F^{0.4474}$ (£/km)

By doing this the optimal transmission capacity is 700 MW, instead of 607 MW for the linear investment model. Figure 3-20 shows the transmission congestion (TCC) and investment cost curves shown in Figure 3-10 including the impact of the economies of scale on the transmission capacity. Naturally economies of scale mean a higher optimal transmission capacity due to the lower cost of adding one additional MW of capacity in comparison to the linear modelling around the optimal value. As a consequence of this result, in the real network of this example the SRMC surplus (or TCC) covers only 48% of the investment cost (compared to 100% for the linear modelling).

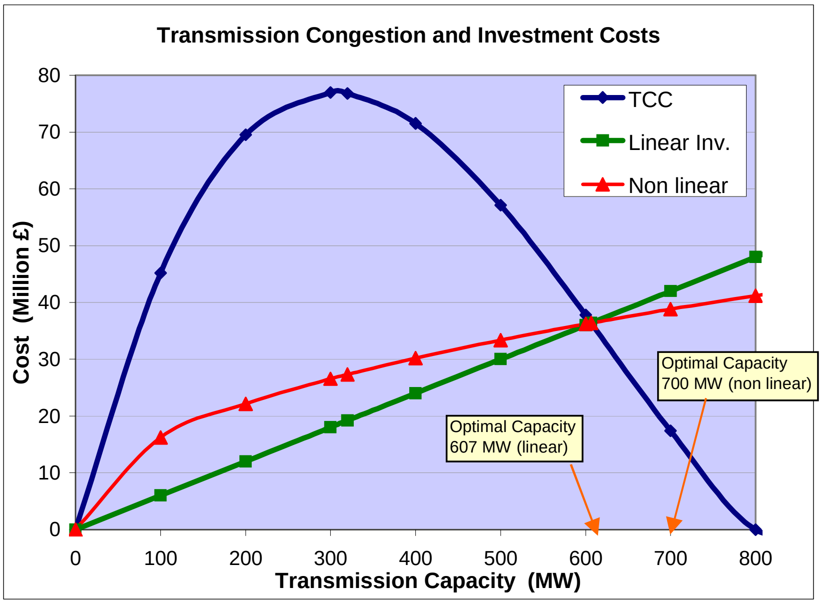


Figure 3-20 Impact of the transmission investment modelling on the optimal transmission capacity

Therefore economies of scale in transmission investments must be taken into account when the economically adapted network is determined by the regulator in order to recognise a relevant characteristic of the transmission business. So some revenue reconciliation method must be defined to complete the pricing process in real networks.

3.7.2 Security of service requirements

Transmission networks provide security of service to the electricity consumers connected to them. The interconnection of power plants via the transmission network reduces the impact of any plant unexpected unavailability over consumers. Therefore a consumer connected to the transmission network have a better level of security of service compared to a consumer that is supplied by a generator not connected to the network (Espinosa, G., 1995). For instance, Figure 3-21 shows the situation of a consumer supplied independently to a generator with a typical figure of 85% availability and its comparison with the situation of the same consumer when it is connected to the transmission network with a typical 99.99% availability.

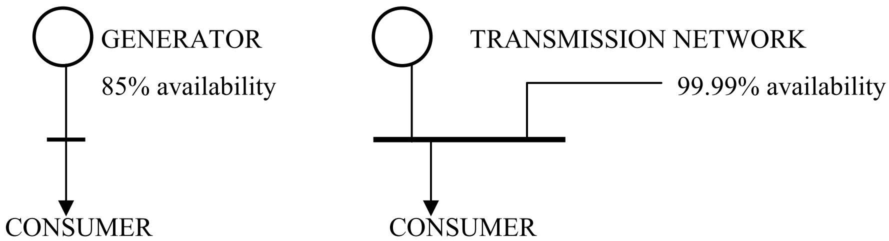


Figure 3-21 Security of service provided by the network

Furthermore, the outage cost is higher for consumers than for generators and then a forced outage on the transmission network affects them more deeply. On the other side, an outage on a transmission line would cost a generator only the lost of revenues due to the energy not sold in the energy market (energy market price less production cost of the plant per MWh not sold). However, at the demand side usually electricity is a product that affects the whole production for industrial consumers, the whole business for commercial consumers and the whole life for residential consumers. So the outage cost or cost of the energy not supplied can be very high for consumers. Table 3-10 presents the impact of different values of the outage cost for consumers on the optimal transmission capacity of the network of Figure 3-22, for the same example of section

3.5, assuming that demand D_k is supplied in a radial way from node 'j' and G_k represents a 'virtual' generator with a marginal cost equal to the outage cost.

Table 3-10 Impact of the outage cost on the network capacity

Outage Cost £/MWh	Optimal Capacity MW	Supplied Demand %	Unavailable Period Hours	Availability %
100	754	94.3%	837.3	90.4%
500	793	99.1%	127.6	98.5%
1000	797	99.6%	61.8	99.3%
2000	798	99.8%	30.5	99.7%
3000	799	99.9%	20.2	99.8%

While higher is the outage cost, higher is the supplied demand D_k (quotient between the optimal capacity F and the maximum demand D_k: 800 MW) and the availability at node 'k' in the yearly period. In summary, consumers must afford all transmission over-investments derived from security of service requirements, for instance the use of the 'N-1' criteria.

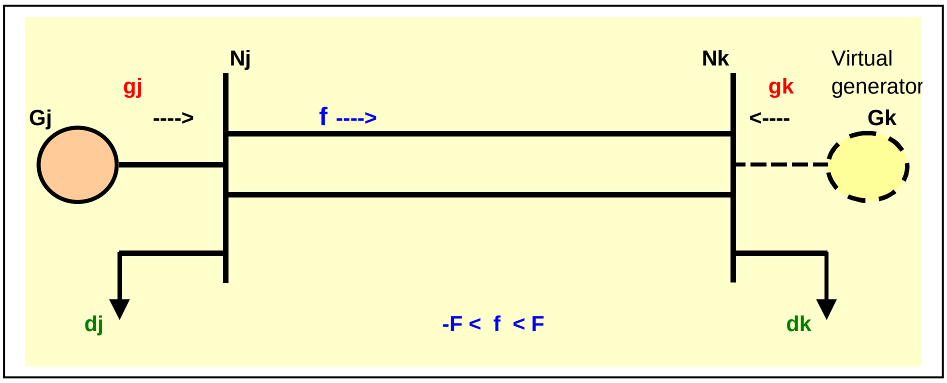


Figure 3-22 Security of service in a radial network.

CHAPTER 4

Transmission rights, SRMC surplus and investments

Summary

This chapter describes the use of SRMC surplus for transmission pricing purposes and its practical application as 'transmission rights'. Transmission rights experiences in the US are discussed and the application of 'firm access rights' in Englang and Wales is commented in detail. Transmission pricing based on SRMC is tested on a three bus network and on the IEEE 24 bus Reliability Test System. Tests of the method probed that nodal SRMC cannot address a right allocation of revenues to recover investments in meshed networks.

4.1 Main concepts

In recent years some of the world's deregulated electricity industries have exhibited a preference for the use of market mechanisms to price the use of transmission systems. These mechanisms typically rely on 'transmission rights' whereby holders of rights are guaranteed access to the transmission network, to inject or withdraw electricity at different locations in the grid. Transmission rights schemes are currently in use in the PJM and California markets in the US complementing the energy markets. A similar scheme based on firm access rights (FAR) has been proposed as part of the New Electricity Trading Arrangements (NETA) in England and Wales.

Transmission rights are a market-based way to discover the value of the transmission network. They were developed as a market mechanism to insure their owners against the delivery risk as a result of location-specific energy contracts (Bushnell, J., 1999). The idea is to create a kind of property right that, for a price, can provide the equivalent of guaranteed access to the energy market at a location, regardless of transmission capacity constraints.

The first scheme to deal with transmission access rights in the short term was proposed by Hogan (Hogan, W., 1992) under the name of Transmission Congestion Contracts (TCC) or Contract Network Rights, with the main purpose of protecting users of the grid from volatility in spot prices caused by transmission congestion. TCC permit their owners to be paid the price difference between two nodes or inject power into and withdraw power out of the system. However, TCC are mainly designed as short term tools that hedge users of the grid against the nodal pricing impact in a competitive basis and not as a mechanism to permit the full recovery and allocation of the investment costs of the grid. Another market scheme is known as property rights. This scheme developed by Chao and Peck (Chao, H.P. and Peck, S., 1996) was designed to deal with externalities problem caused by loop flows in the grid. It allocates the transmission rights following specific trading rules that recognise the impact of externalities.

Transmission rights have been developed under a physical or a financial form. A physical right of one MW entitles its owner to inject one MW of power at a certain node and withdraw one MW at other node. A physical right has been paired as “right-of way” on the network for the power belonging to a given generator. A one MW financial right entitles its owner to receive the difference of prices between two nodes. A financial right has been assimilated to an option contract that guarantees its owner the right to sell power at the spot price at a certain location in the network, regardless of where the power is injected into the network. Transmission rights have also been broadly studied in relation to the incentives of participants in the energy market to exercise market power (Bushnell, J., 1999). Joskow and Tirole (Joskow, P. and Tirole J., 1998) have also analysed both financial and physical rights and their interaction with market power.

4.2 Applications of transmission rights in the US

In 1998 a Fixed Transmission Rights (FTR) scheme was introduced by the independent system operator (ISO) for the Pennsylvania, New Jersey and Maryland Interconnection (PJM) to provide a hedging mechanism against the financial impact of the energy market's Locational Marginal Prices (LMP). In PJM, FTR are obtained by one of the following ways:

- As a network service, based on annual peak load or designated from resources to loads.
- As a firm point-to-point service from source to sink.
- By bilateral trading of existing FTR in secondary markets.
- By FTR auction of additional transmission capacity in a centralised market.

In PJM, FTR are a financial (not physical) entitlement, independent of the energy delivery and whose value (positive or negative) is determined by hourly LMP and the direction and magnitude of congested flows. FTR monthly auctions provide a way for allocating the remaining FTR capability on the PJM transmission system at the time of closing the auction quoting period. They allow market participants to bid for or sell existing FTR. The winning bids are determined by solving a DC load flow model that maximises the bid-based value of the FTR market, after checking the simultaneous feasibility with prior committed FTR. This last process must ensure that there are enough revenues for transmission congestion charges to satisfy all FTR obligations for the auction.

In 1999 the California Independent System Operator (ISO) established a mechanism of Firm Transmission Rights (FTR) in a similar way to PJM. However, the Californian energy market is based on a bilateral model and the ISO operates three markets close to real time: Ancillary Services, Congestion Management and Energy Imbalance. The Congestion Management Market is used to adjust the schedules, allocating transmission capacity to those who value it most. The transmission system has been divided in four zones based on areas where congestion is infrequent and they are priced on an average cost basis. Thus, zonal locational prices are calculated instead of LMP for the whole grid as in PJM. Congestion management and pricing can be inter-zonal, meaning congestion between zones or intra-zonal, meaning congestion within a zone. An FTR holder has both physical scheduling and financial rights in the ISO's day-ahead market but only financial rights in the hour-ahead market. The revenues collected from auctions are credited to the entities paying for the fixed costs of the transmission system and therefore are netted off the access charges payable to the transmission owners (TO).

The new ISO of the New York Power Pool introduced in 1999 a scheme of Transmission Congestion Contracts (TCC) similar to FTR in PJM. A scheme of Firm Transmission Rights (FTR) was also introduced by the New England ISO in year 2000.

4.3 Transmission rights and NETA

In England and Wales, a new transmission access and pricing regime based on Firm Access Rights (FAR) has been recently proposed by the Office of Gas and Electricity Markets (Ofgem) as part of its New Electricity Trading Arrangements (NETA). According to Ofgem (Ofgem, 1998) "the current trading arrangements provide no short-term locational price signals to either generators or demand". Among the objectives of NETA related to transmission reforms is the application of market-based rather than centrally administered mechanisms to be used by NGC as system operator (SO) to accomplish its activities, allowing participants to express their preferences.

Figure 4-1 shows a basic scheme of the proposed operation of the energy and access markets. Both markets will meet at the balancing mechanism, where energy unbalances of participants will be solved by the SO, taking into account their FAR to inject into or withdraw energy from the network.

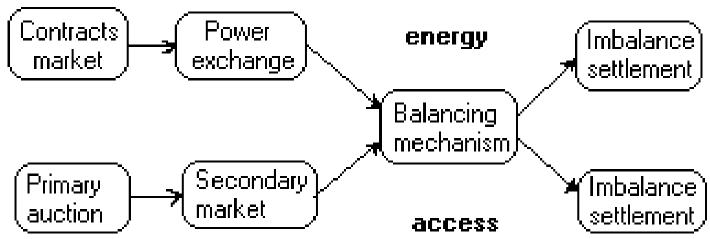


Figure 4-1 Energy and access markets under NETA

According to the NETA proposals, FAR will be "allocated to participants and subsequently traded in such a way that the market determines the value of transmission access and use". Some characteristics of the proposed FAR scheme are:

- If the SO wishes to reduce a participant's access right allocation, it has to compensate it.
- Congestion management achieved by the SO buying back existing FAR.
- Definitions between the use of entry/exit rights to a zone or transfer rights between zones.
- "Use it or lose it" provisions to prevent holders not utilising their FAR.
- Over-run charges to discourage participants from generating or demanding in excess of their FAR.
- Initial allocation of FAR by auctions.
- Use of a top-down approach to determine the volume of FAR to be sold by the SO at the initial allocation.
- Combination of long-term and short-term FAR to be sold.

4.4 Firm Access Rights issues

Following the basic principles of an efficient pricing scheme, reviewed in section 2.1, the main issues concerning the use of FAR for transmission pricing are:

4.4.1 Short term issues in FAR

• Open access and economic efficiency

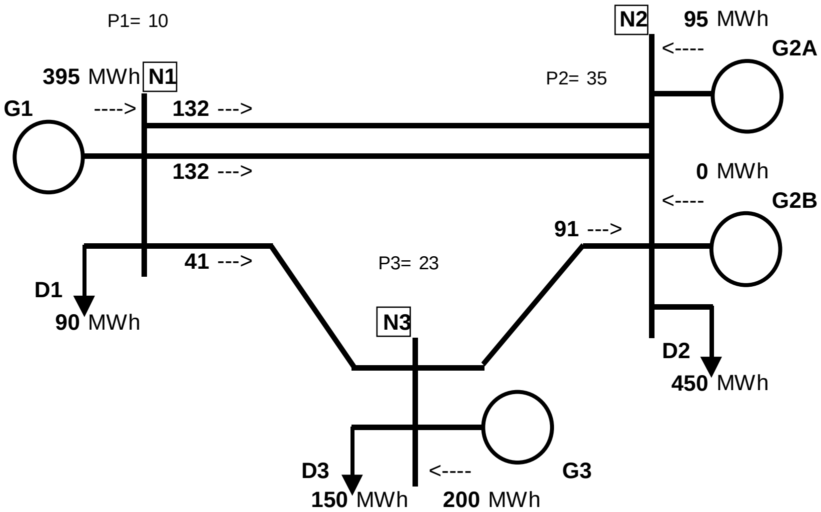
FAR scheme should provide a mechanism to trade energy freely in the network taking into account the impact of transmission constraints. An issue of concern is the proposed "discovery of the market value of transmission access and use" by the allocation to and trading of FAR by participants.

In a bilateral energy market, the short run value that participants are willing to pay for transmission can be explained using a perfect market representation. In such a market, the value of the transmission service (including costs of congestion and losses) is found as LMP differentials between nodes. In the proposed bilateral market for England and Wales, participants in FAR auctions will have to value the access to the network in co-ordination with their bilateral energy contracts and self-despatch. SO should not allow a bilateral transaction in the energy market or an unbalanced transaction without the corresponding FAR. Thus, economic efficiency in the energy market will be critically dependent on the level of competition achieved in the transmission access market. Any gaming or exercising market power could affect the economic efficiency in the energy market. So, participants who own FAR should have the right to inject into (entry) or withdraw power from (exit) the network in perfect tune with their balanced portfolio of generation and demand. Also, participants who do not buy FAR are expected to pay over-run charges. In that sense, FAR would be a particular type of physical rights.

• Volume of rights to be sold

This is a very critical issue directly related to the value of the rights in the market. For example, the lower the amount of rights offered by the SO (implying lower capacity declared in the access market), the higher the value of FAR. The close relationship between the access and energy markets will affect the willingness to pay for FAR by users and this fact could motivate the SO to raise the value of FAR. SO and TO activities performed by the same company, not an independent SO like in the US, could potentially generate perverse incentives and the exercise of market power by the SO to benefit its TO side. Instructing the SO to sell the maximum level of capacity available (top-down approach) seems adequate to mitigate its market power.

Figure 4-2 shows a 3-node lossless network used to illustrate the relationship between the value and the amount of rights in a perfect market. Economic despatch, flows and nodal prices to supply a 690 MW demand were determined using the model developed in section 4.5.1.1.. Prices (P) at nodes are also shown in £/MWh. If, for example, the thermal capacity of each circuit of line L12 is 300 MW, we can examine the impact of a SO reducing the capacity of path L12 from 300 MW (i.e. selling a lower amount of FAR).



Plant bids and max/min gen.

	£/MWh	Gmin	Gmax
G1	10	0	500
G2A	35	0	150
G2B	50	0	120
G3	20	0	200

Line reactance and capacity

	X (o/1)	MW
L12-1	0.2	220
L12-2	0.2	220
L31	0.2	160
L23	0.2	200

Figure 4-2 Network to calculate the value of rights

Figure 4-3 shows the market value of FAR measured as the difference of prices between nodes 2 and 1, as a function of the available capacity of path L12. The price of rights is zero for capacities over 287 MW and extremely high for capacities less than 103 MW. For capacities lower than 103 MW there is not enough generation at node 2 and the price at this node should be equal to the customers' cost of energy not supplied. So, the optimum social welfare level could be lost under monopolistic gaming.

So the question is - what is the volume of rights the SO should offer to primary auctions? Nevertheless, who will perform an ex-post analysis of thousands of transactions in the access and energy markets to check that all the capacity was really available?

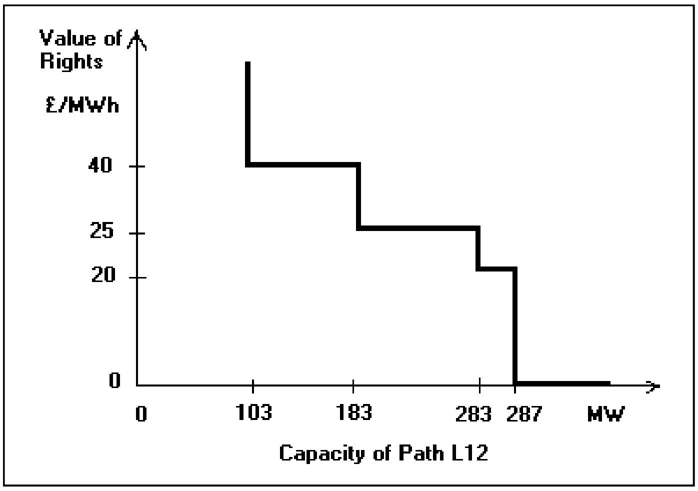


Figure 4-3 Value and amount of rights

• Market power

One form of market power exercised by the SO was described above. Generators and suppliers also could exercise market power in particular operational conditions of the system. They could create constraints that do not exist by buying and holding FAR. In the presence of congestion in a particular path, generators on the importing side increase their market power, while suppliers on the exporting side could also do the same. The SO could also be affected by market power exercised by FAR holders when buying back rights to reduce the amount of FAR to manage congestion. The impact of market power could be reduced by more participants offering their FAR for sale and providing transparent information in the market to facilitate decisions. It could be done defining zones with enough participants.

• Congestion management

The SO is expected to solve congestion by buying back FAR in the access market. Under this arrangement, the SO will have to pay the market value of congestion to the participants who want to modify their energy scheduling. Nevertheless, those participants will have to rearrange their energy balance, for example by despatching more expensive generation at the importing side. However, the amount of congested paths could be a very difficult issue to manage, especially in large transmission systems. Then, a nodal approach to manage congestion and defining FAR from entry nodes to exit nodes could be a very difficult task under a bilateral market structure. A zonal approach must be preferred in that case, allowing an easier definition of FAR between a few zones than many nodes. An adequate zonal definition also should mitigate the impact of market power of participants, allowing more of them offering their FAR for sale.

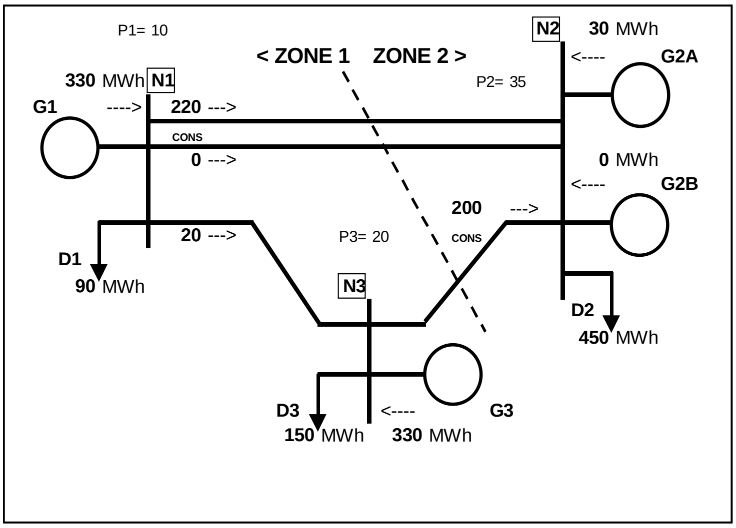
Inter-zonal congestion would be solved using transfer FAR between zones and the balancing mechanism in real time, if the congestion could not be relieved completely. However, intra-zonal congestion cannot be solved in the same way. It is intended to be resolved in the balancing mechanism, as shown in Figure 4-1.

• Determination of zones and their dynamics

Definition of zones for the first time is a complex task. Only the SO has the experience and information about more frequently congested paths. Nevertheless, the new trading arrangements could change the pattern of generation and demand, producing congestion at different paths or modifying the intensity and frequency of congestion at typically congested paths. Therefore, a first definition of zones should be based on the actual use of the network by existing generators and demand but allowing a future redefinition of zones according to the real market operation. The setting rule should consider the frequency and economic impact of congestion at every path, to identify geographically close sets of nodes which could be considered as one node, linked to other sets of nodes by the frequently congested paths or interfaces.

Based on operational experience, the SO should modify the extension of the zones, transferring nodes from one zone to another or creating a new zone, for example if an intra-zonal congestion becomes frequent and economically relevant. Using the same network of Figure 4-2 but increasing capacity of generator 3 to 400 MW, Figure 4-4 shows alternative definitions of the interface between Zones 1 and 2 depending on the bidding strategy of generator 3.

Generator G3 is bidding at 20£/MWh



Generator G3 is bidding at 60 £/MWh

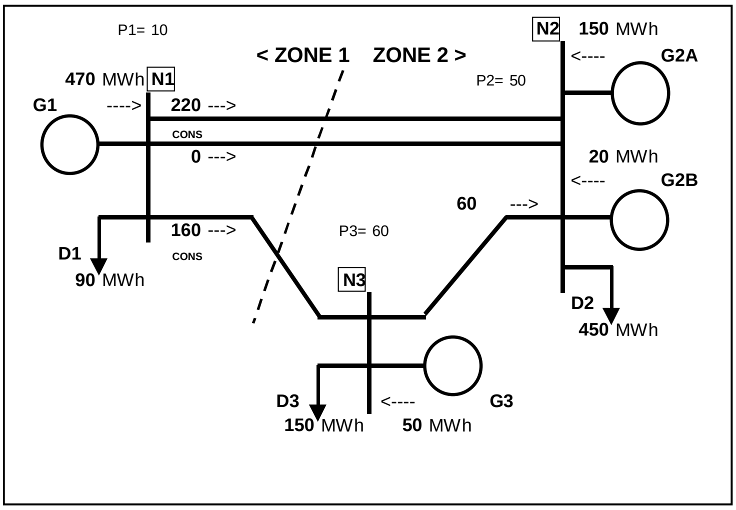


Figure 4-4 Determination of zones and bidding

4.4.2 Long term issues in FAR

• Revenue recovery

In the absence of market power, FAR would normally recover only part of the total costs of the transmission network. World experience in the practical use of LMP in transmission shows that they only allow a recovery between 10% and 20% of the network total costs (Rudnick, H., *et al* 1999). It is expected to be lower in a strong transmission system such as that of NGC. It means that some kind of revenue reconciliation will be needed to recover NGC's total transmission costs. So, the question arises regarding the way the 80% to 90% of the total costs of transmission will be recovered, considering that today those costs are allocated using locational charges.

Another issue of concern relates to the way to recover the transmission costs inside a zone, where FAR are not on sale.

• Cost or value based pricing

Pricing of transmission services can be based on either cost of the service or value of the service concept (Mutale, J., 2000). While value based pricing is appropriate for competitive markets like electricity generation or supply, it is not obvious if such schemes are also appropriate for monopoly functions such as transmission. As indicated earlier, value based pricing would need some kind of revenue reconciliation mechanism or additional charge to cover the total costs of the transmission system. In that sense, discovering the market value of transmission by allocating FAR does not seem an adequate mechanism for addressing short and long run issues in a consistent manner. A scheme based on the cost of the service concept seems more appropriate to price transmission in the long term.

• Ability to signal location of new generation and demand

In a stable market, long-term signals for allocation of new generation and demand are the response to short run costs of constraints. It means that electricity will get a locational value. In that sense, FAR is an efficient scheme to signal the entrance of new participants.

• **Ability to signal investments in transmission**

Long-term signals for investments are the result of short run costs of constraints. Then, participants could determine the value that additional capacity have for them. However, uncertainties regarding revenue recovery, long periods of construction and free riding attitude of some participants should impede the development of transmission capacity on a market basis.

Moreover, as it is demonstrated in section 4.5, tests of an SRMC-based transmission pricing scheme probed that investments are not matched with SRMC revenues coming up from the energy market on a line per line basis. Therefore, short run signals aim on the right direction but they are distorted by the complexities of meshed networks.

4.5 Transmission pricing based on SRMC

Following the analysis of the main concepts regarding the application of SRMC for transmission pricing in a two nodes network, performed in Chapter 3, in this section SRMC pricing will be explored in bigger networks.

4.5.1 Tests on a 3-bus network

The first tests were performed on a 3-bus meshed network with 3 demand periods, that contains the main difficulties usually found on bigger networks.

4.5.1.1 Formulation of the problem

The 3-bus network optimal despatch and investment solution was formulated as a linear optimisation problem and solved using the routine Solver provided as one of the tools by MS Excel. The network equations are formulated through the use of generalised generation distribution factors, also known as GGDF (Ng, W., 1981).

The problem was formulated on a long term basis in order to study the relationship between the SRMC transmission revenue and transmission investments. The formulation of the long term optimisation programme follows:

$$Minimise: OIC(g_j, F_l^{max}) = \sum_{p=1}^{NP} nh_p \cdot \sum_{j=1}^{NG} c_j \cdot g_j^p + \sum_{i=1}^{NBR} a_i \cdot l_i \cdot F_i^{max} \tag{4-1}$$

$$G_j^{min} \le g_j^p \le G_j^{max} \qquad 1 \le j \le NG;\ 1 \le p \le NP \tag{4-2}$$

$$\sum_{j=1}^{NG} g_j^p = d_p \qquad 1 \le p \le NP \tag{4-3}$$

$$0 \le F_i^{max} \le \infty \tag{4-4}$$

$$-F_i^{max} \le f_i^p \le F_i^{max} \tag{4-5}$$

$$f_i^p = \sum_{k=1}^{NBUS} GGDF_{ki} \cdot g_k^p \tag{4-6}$$

The symbols used in the above equations are defined below:

NP	- Number of demand periods
NG	- Number of generators
NBR	- Number of branches (lines)
$NBUS$	- Number of buses (nodes)
nh_p	- Duration of demand period p
d_p	- Nodal demand for period p
c_j	- production cost of generator j
$g_j{}^p$	- despatch of generator j during demand period p
$g_k{}^p$	- despatch of generators connected at node k, during demand period p
$G_j{}^{min}$	- minimum despatch of generator j
$G_j{}^{max}$	- maximum despatch of generator j
a_i	- annuitised investment factor of line i (£/MW-km-year)
l_i	- length of line i (km)
$F_i{}^{max}$	- transmission capacity of line i (MW)

f_i^p - power flow by line i during period p

$GGDF_{ki}$ - generalised generation distribution factor for line i and node k

The solution of the optimisation problem (4-1) calculates the generation despatch g_j^p in each demand period, power flows per line in each demand period f_i^p and the optimal circuit capacities F_i^{max} for every line.

Calculation of nodal LRMC (λ_k^p, at node k during demand period p) is performed using the general formulation presented in Appendix A, with a specific equation when GGDF are considered. Analogously nodal SRMC are calculated in the same way when the problem is solved considering a fixed transmission capacity (short term formulation).

$$\lambda_k^p = \lambda^p + \sum_{i=1}^{NBR} GGDF_{ki} \cdot \tau_i^p \qquad (4\text{-}7)$$

In equation (4-7), λ^p are the Lagrange multipliers associated to the demand constraint equation (4-3), also called 'system marginal costs', on every demand period p and τ_i^p are the Lagrange multipliers associated to the transmission constraints represented by equation (4-5).

4.5.1.2 Results

The following example presents a comparison of transmission pricing based on SRMC and LRMC. The example has been developed on the three bus power system shown in Figure 4-5 and three demand periods are considered. The main data of the system are as follows:

- Generators capacities: G1= 400 MW, G2A= 210 MW, G2B= 60 MW, G3= 100 MW
- Production costs: G1=10 £/MWh, G2A=22 £/MWh, G2B=40 £/MWh, G3=15 £/MWh
- Demand periods: 100%, 75% and 50% of peak demand with a duration of 720 hours, 2800 hours and 5240 hours respectively
- Line reactance and length: 0.2 p.u. and 300 km respectively, every line
- Transmission annuity investment factor: 53 £/MW-km-year

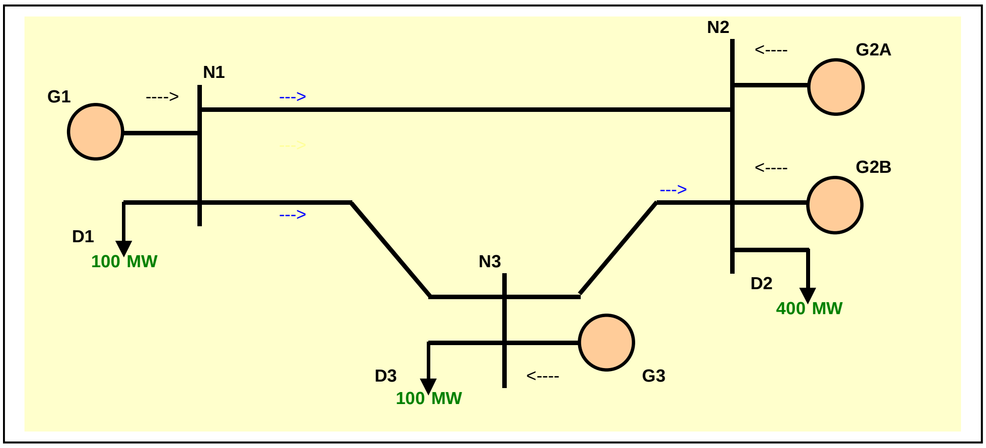


Figure 4-5: Three bus power system

- **Economically adapted network (EAN)**

The EAN is determined via the minimisation of the total annual operation and transmission annuitised investment costs. Optimal transmission capacities per line are determined as a result of the minimisation process. In the example the optimal transmission capacities per line that result are: L12= 208 MW, L23= 92 MW and L13= 117 MW. Those values of transmission capacities permit a perfect trade off between operation and investment costs from a system point of view. Total operation cost is 34,627 Thousand £ and the optimal transmission annuitised investment cost is 6,625 Thousand £.

- **Transmission pricing based on LRMC**

Long-Run Marginal Costs (LRMC) are derived from the optimal solution of the long term operation plus investment problem. Thereby the solution is the same already found to determine the EAN. The LRMC correspond to the marginal increase of the total operation and investment costs when an additional unit of demand is required. In the same way, nodal LRMC can be determined and they refer specifically to the increase in the total long-term cost when an unit of demand is required at a particular node of the system. The values of the LRMC are shown in Table 4-1.

Table 4-1: LRMC (£/MWh)

	Node 1	Node 2	Node 3
Period 1	18.5	22.0	15.0
Period 2	10.3	17.0	15.0
Period 3	10.0	10.0	10.0

The despatch by generators, power flows by line and LRMC at every node of the system are deployed in Appendix B, for everyone of the periods.

A remarkable characteristic of the application of nodal LRMC as a transmission pricing method is the fact that the nodal LRMC surplus is equal to the total transmission investment cost. Table 4-2 presents the LRMC transactions in the system. Table 4-3 presents the transmission investment costs.

Table 4-2: LRMC Transactions (Thousand £)

Generation	Period 1	Period 2	Period 3	Total
G1	5328	11552	15720	32600
G2A	1782	0	0	1782
G2B	0	0	0	0
G3	945	2100	0	3045
Total Generation	8055	13652	15720	37427
Demand	Period 1	Period 2	Period 3	Total
D1	-1332	-2166	-2620	-6118
D2	-6336	-14268	-10480	-31084
D3	-1080	-3150	-2620	-6850
Total Demand	-8748	-19584	-15720	-44052
Total Gen. + Demand	-693	-5932	0	-6625
Transmission	Period 1	Period 2	Period 3	Total
L12	493	3892	0	4385
L23	462	510	0	972
L31	-262	1531	0	1268
Total Transmission	693	5932	0	6625

Table 4-3: Transmission Investment Costs (Thousand £)

Optimal Transmission Investment				
Line	Capacity MW	Length km	Cost £/MW-km	Annuity of Investment Th. £
L12	208	300	53	3313
L23	92	300	53	1457
L31	117	300	53	1855
Total Transmission Investments				6625

In spite of the equality between the total LRMC surplus and the total transmission investments, on a line per line basis this situation cannot be obtained. Comparing figures of Table 4-2 and Table 4-3, although total figures fit perfectly, LRMC surplus and investments per line are quite different.

A simple example can be performed (for instance opening one of the lines of the network) to demonstrate that in a radial network this line per line equality is obtained. This example for a radial network is presented in Appendix B. Therefore the problem relates to meshed networks.

The reason to explain why the equality on a line per line basis cannot be achieved is simple: LRMC depend on flows per line that must follow the Kirchhoff Voltage Law (KVL) on parallel paths, on the other side, transmission investments per line do not have any relationship with KVL. In other words, power flows and LRMC (or SRMC) revenue follow KVL but transmission investments do not.

This is a very important conclusion regarding the application of short-run transmission pricing methods like transmission rights, especially when they are considered as physical rights and it is expected that in the long-run physical rights signal and drive investments in the transmission network. KVL is a unique characteristic of electrical networks and then the access pricing applied to electricity networks must differ from other similar industries like gas transportation, where there is no such physical restriction. In conclusion, if a method of physical rights like FAR is put in place then some cross subsidies will appear as a consequence of parallel paths on real networks (meshed) because a long-term price difference between two nodes not necessarily mean that every parallel line needs a reinforcement in its transmission capacity.

- **Transmission pricing based on SRMC**

Short-Run Marginal Costs (SRMC) are derived from the optimal solution of the short term operation problem, so only operational costs are considered because transmission capacity is fixed. The SRMC correspond to the marginal increase of the total operation costs when an additional unit of demand is required. In the same way, nodal SRMC can be determined and they refer specifically to the increase in the total short-term cost when an unit of demand is required at a particular node of the system. Calculation of SRMC is performed with the same equations indicated for LRMC but the main difference is on determination of Lagrange multipliers, which are different for the long-term and short-term problem. The values of SRMC are shown in Table 4-4.

Table 4-4: SRMC (£/MWh)

	Node 1	Node 2	Node 3
Period 1	18.5	22.0	15.0
Period 2	10.0	22.0	15.0
Period 3	10.0	10.0	10.0

It can be noted that SRMC figures are quite similar to LRMC, nevertheless they differ on period 2 because in the short term transmission capacity is fixed and then an additional MWh required at a node must be supplied only with local generation if a transmission constraint is binding. In the long term, an additional MWh demanded at a node can be supplied with an optimal mix of local generation and far generation transported from neighbouring nodes via optimal adjustments on transmission capacity of the corresponding links. This situation can be observed at nodes 1 and 2 in period 2.

Table 4-5 presents the SRMC transactions in the system. It can be observed that the SRMC revenue has no relationship with the value of the transmission investment costs presented in Table 4-3.

Table 4-5: SRMC Transactions (Thousand £)

Generation	Period 1	Period 2	Period 3	Total
G1	5328	11200	15720	32248
G2A	1782	0	0	1782
G2B	0	0	0	0
G3	945	2100	0	3045
Total Generation	8055	13300	15720	37075
Demand	Period 1	Period 2	Period 3	Total
D1	-1332	-2100	-2620	-6052
D2	-6336	-18480	-10480	-35296
D3	-1080	-3150	-2620	-6850
Total Demand	-8748	-23730	-15720	-48198
Total Gen. + Demand	-693	-10430	0	-11123
Transmission	Period 1	Period 2	Period 3	Total
L12	493	7000	0	7494
L23	462	1797	0	2259
L31	-262	1633	0	1371
Total Transmission	693	10430	0	11123

In conclusion, the SRMC surplus cannot be considered an effective transmission pricing method because it has no relation with transmission investments. Therefore it is better to consider the SRMC surplus as a sub-product of the energy market which can be used to create a set of financial rights for hedging purposes, for instance.

4.5.2 Tests on the IEEE 24-bus network

4.5.2.1 Formulation of the problem

The tests were carried out on the modified IEEE 24-bus Reliability Test System (IEEE RTS, 1979) whose topology, basic parameters and data are given in Appendix C. The 24-bus network optimal despatch and investment solution was found using a computational programme developed on a previous research at UMIST (Nield, S., 2000). The programme is written in 'C' language and the problem is formulated as a linear optimisation using CPLEX.

The formulation of the long term optimisation programme follows:

$$Minimise: OIC(g_{\mathrm{j}}, F_l^{max}) = \sum_{p=1}^{NP} nh_p \cdot \sum_{j=1}^{NG} c_j \cdot g_j^p + \sum_{i=1}^{NBR} a_i \cdot l_i \cdot F_i^{max} \tag{4-8}$$

$$G_j^{min} \leq g_j^p \leq G_j^{max} \qquad 1 \leq j \leq NG;\ 1 \leq p \leq NP \tag{4-9}$$

$$\sum_{j=1}^{NG} g_j^p = d_p \qquad 1 \leq p \leq NP \tag{4-10}$$

$$0 \leq F_i^{max} \leq \infty \tag{4-11}$$

The symbols used in the above equations are the same already defined in section 4.5.1.1.

Transmission constraints generated as part of the optimisation process are added as additional rows to the linear programming problem. These constraints are defined using the Security Constrained Optimal Power Flow (SCOPF) method, and they are written as follows:

$$-F_i^{max} \leq f_i^{p0} + \sum_{k=1}^{NBUS} h_{ki}^S \cdot (g_k^p - g_k^{p0}) \leq F_i^{max} \tag{4-12}$$

where S represents the system topology (*intact*, if the network is operating without outages, or *contingency*, if the network is operating with a security criteria like 'N-1', with one line out of service) and $h_{ki}{}^S$ are elements of the sensitivity matrix $[H] = [Y_d] \cdot [A^T] \cdot \begin{bmatrix} 0 & 0 \\ 0 & [Y_{bus}^r]^{-1} \end{bmatrix}$.

The solution of the optimisation problem (4-8) calculates the generation despatch $g_j{}^p$ in each demand period, power flows per line in each demand period $f_i{}^p$ and the optimal circuit capacities F_i^{max} for every line.

Calculation of nodal LRMC ($\lambda_k{}^p$, at node k during demand period p) is performed using the general formulation presented in Appendix A, with an specific equation when the

SCOPF method is considered. A special function written in 'C' language was developed and added to the optimal transmission capacity programme to perform the calculations. Analogously nodal SRMC are calculated in the same way when the problem is solved considering a fixed transmission capacity (short term formulation).

$$\lambda_k^p = \lambda^p + \sum_{s=S1}^{NSYS} \sum_{i=1}^{NBR} h_{ki}^S \cdot \tau_i^{pS} \qquad (4\text{-}13)$$

In equation (4-7), λ^p are the Lagrange multipliers associated to the demand constraint equation (4-10), also called 'system marginal costs', on every demand period p and τ_i^{pS} are the Lagrange multipliers associated to the transmission constraints added to the optimisation problem, and represented by equation (4-12).

4.5.2.2 Results

Departing from the data of the IEEE 24-bus network given in Appendix C, the economically adapted network was determined and consistency of LRMC pricing versus transmission investment was verified. Five demand periods were considered in the analysis.

- **Economically adapted network (EAN)**

The EAN is determined via the minimisation of the total annual operation and transmission annuitised investment costs of the problem described by equation (4-8). Total operation cost is 147,059 Thousand £ and the optimal transmission annuitised investment cost is 10,279 Thousand £. Figure 4-6 shows the maximum power flows by branch of the network for the EAN and the network not constrained in comparison to the capacities of the existent network. It is remarkable the need for more capacity on branches 12 and 13 whose maximum flows are 69% over the existent capacity without transmission constraints and only 24% over the existent capacity for the EAN.

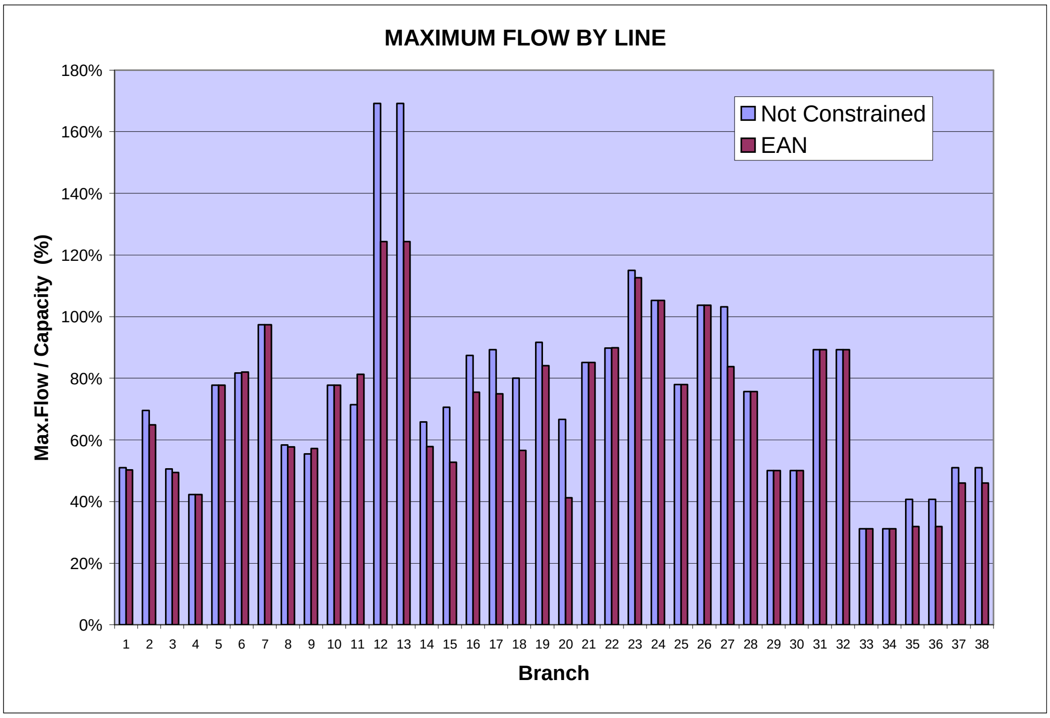


Figure 4-6: Maximum power flows of the EAN and the network not constrained compared to the existent capacity

- **Transmission pricing based on LRMC**

Table 4-6 presents the SRMC transactions for the not constrained network and the EAN, whose total revenue is equal to the annuitised transmission investment cost (10,279 Thousand £). Table 4-7 presents the nodal LRMC and the SMP on every demand period. Finally Table 4-8 deploys the LRMC revenues by branch compared to the individual optimal investment cost. In spite of the perfect match between total LRMC revenue and the transmission investment cost for the EAN, once more LRMC pricing fails on a branch by branch basis.

Table 4-6: SRMC Transactions (Thousand £)

SRMC Revenues (Costs)

Not Constrained network

	Period 1	Period 2	Period 3	Period 4	Period 5	Total
Generation	19,083	99,471	79,733	56,916	25,633	280,836
Demand	-19,083	-99,471	-79,733	-56,916	-25,633	-280,836
Transmission	0	0	0	0	0	0
Operational Cost	-9,732	-43,303	-45,132	-35,253	-13,538	-146,958
Out-of-Merit G.Cost.	0	0	0	0	0	0

IEEE 24-Bus EAN

	Period 1	Period 2	Period 3	Period 4	Period 5	Total
Generation	20,228	99,444	68,581	56,915	21,714	266,883
Demand	-21,201	-99,757	-74,576	-57,094	-24,535	-277,162
Transmission	973	313	5,995	178	2,820	10,279
Operational Cost	-9,786	-43,351	-45,132	-35,253	-13,538	-147,059
Out-of-Merit G.Cost.	54	47	0	0	0	101

Table 4-7: Nodal LRMC and SMP by period (£/MWh)

Node	1	2	3	4	5
1	25.7	23.2	15.3	12.7	11.8
2	25.7	23.2	15.3	12.7	11.8
3	25.7	23.3	14.8	12.4	11.6
4	29.1	23.3	15.2	12.7	11.9
5	25.7	23.5	15.3	12.7	11.9
6	32.6	23.3	15.3	12.6	11.9
7	24.0	24.0	15.8	12.4	11.9
8	25.7	24.0	15.8	12.4	11.9
9	25.7	23.3	15.1	12.4	11.9
10	25.7	23.4	15.4	12.4	11.9
11	26.5	23.3	14.4	12.4	12.0
12	25.0	23.3	14.5	12.4	12.0
13	23.3	23.3	14.3	12.4	12.0
14	26.9	23.3	14.1	12.4	12.0
15	25.6	23.3	13.0	12.4	11.1
16	25.6	23.3	13.0	12.4	11.7
17	25.6	23.3	13.0	12.4	10.3
18	25.6	23.3	13.0	12.4	10.1
19	25.9	23.3	13.2	12.4	11.7
20	26.1	23.3	13.3	12.4	12.1
21	25.6	23.3	13.0	12.4	10.4
22	25.6	23.3	13.0	12.4	8.1
23	23.3	23.3	13.3	12.4	12.1
24	25.7	23.3	14.2	12.4	11.3
SMP	23.3	23.3	15.3	12.4	12.1

Table 4-8: LRMC revenue and Transmission investment cost (Thousand £)

Branch	SRMC revenue (Thousand £) 1	2	3	4	5	Total	Investment cost (Thous. £)	%Inv.
1	0.0	0.3	0.0	1.7	0.3	2.3	7.9	29%
2	0.1	-2.5	96.5	43.7	24.1	161.9	187.3	86%
3	0.1	29.1	0.3	-0.8	-0.7	28.0	57.1	49%
4	25.7	2.8	3.5	-2.2	-0.7	29.1	73.3	40%
5	78.5	9.2	0.8	1.1	-0.4	89.3	204.0	44%
6	0.1	1.7	49.0	-1.3	20.8	70.2	133.5	53%
7	1.4	-6.0	370.6	2.4	91.0	459.4	584.2	79%
8	47.6	-1.9	13.8	53.4	-1.6	111.4	81.8	136%
9	0.0	0.0	-3.4	35.5	-3.4	28.6	69.1	41%
10	190.8	-4.2	-2.1	39.9	-2.4	221.9	65.3	340%
11	68.3	0.0	0.0	0.0	0.0	68.3	68.3	100%
12	0.0	147.0	209.0	1.2	3.4	360.7	280.9	128%
13	0.0	109.9	105.3	-0.9	-2.5	211.8	280.9	75%
14	-23.5	-4.1	228.1	-1.9	-14.7	183.9	347.4	53%
15	27.1	-1.9	215.3	-1.4	-12.7	226.4	316.5	72%
16	-32.3	12.4	435.1	1.2	-9.9	406.5	452.6	90%
17	36.1	16.4	417.0	1.8	-9.3	462.0	449.6	103%
18	101.8	0.8	9.5	0.1	-0.3	111.9	280.1	40%
19	-19.4	2.4	206.1	-1.6	-16.9	170.6	365.9	47%
20	37.2	-0.4	13.6	-0.1	-1.4	49.0	204.1	24%
21	106.5	-0.3	821.0	0.2	-31.9	895.4	855.6	105%
22	4.3	1.6	757.4	0.5	-25.4	738.4	808.9	91%
23	125.5	3.9	1212.1	4.6	153.9	1499.9	456.2	329%
24	-0.1	0.4	1.3	-0.3	141.8	143.2	189.4	76%
25	0.9	-3.7	767.2	1.5	56.3	822.1	420.6	195%
26	-0.1	0.5	1.3	-0.2	916.4	917.9	279.8	328%
27	4.7	0.1	72.5	0.1	-16.1	61.3	201.1	30%
28	0.0	0.2	0.4	-0.1	78.5	78.9	113.6	69%
29	0.0	0.1	0.3	0.0	423.5	423.8	547.5	77%
30	0.0	-0.1	-0.2	0.0	469.7	469.5	352.5	133%
31	0.1	-0.3	-0.8	0.1	268.0	267.0	455.5	59%
32	0.1	-0.3	-0.8	0.1	268.0	267.0	455.5	59%
33	0.0	0.0	0.1	0.0	-8.9	-8.9	84.2	-11%
34	0.0	0.0	0.1	0.0	-8.9	-8.9	84.2	-11%
35	-3.6	0.0	-0.3	0.0	37.3	33.4	129.0	26%
36	-3.6	0.0	-0.3	0.0	37.3	33.4	129.0	26%
37	99.4	-0.1	-2.2	0.0	-0.8	96.3	103.5	93%
38	99.4	-0.1	-2.2	0.0	-0.8	96.3	103.5	93%
Total	972.7	312.8	5995.0	178.2	2820.4	10279.2	10279.2	100%

From Table 4-8 it is interesting to observe that only the investment cost of branch 11 is fully paid by the LRMC revenue. This situation occurs because branch 11 is the only one radial branch in the IEEE 24 bus network. All other branches investments are over-paid or under-paid using the LRMC revenue for the EAN. It can also be noticed that branches 33 and 34 have a negative LRMC revenue as a consequence of the Kirchhoff Voltage Law (KVL) constraint in the circuit formed by nodes 17, 18, 21 and 22.

An SRMC pricing analysis for different transmission capacities probes to be not relevant due to the lack of relation between the SRMC surplus and transmission investment. Thus the SRMC surplus will be lower or upper the transmission investment cost of the optimal network depending on the over-capacity or under-capacity of the actual network respectively.

In conclusion, the SRMC surplus cannot price transmission investments because they are not related and moreover the LRMC surplus fails to provide the right revenues for the optimal network. LRMC revenues don't have a match with transmission investments on a line per line basis in meshed networks for the EAN. Then the LRMC method must be discarded for meshed networks nevertheless it can be applied for radial networks. Therefore an SRMC based method like firm access rights (FAR) will fail to meet the objectives pursued by NETA and will not allow the recovery of the investment cost of the existent transmission network for its owner.

CHAPTER 5

Use of the concept of "economically adapted network" for transmission pricing

Summary

This chapter describes the design and tests of a pricing method based on optimal circuit prices derived from the EAN. Beginning from the conceptual design, the method is then tested on a three bus network and on the IEEE 24 bus Reliability Test System. Several case studies are developed on the IEEE 24 bus system to probe the robustness and potential of the method.

5.1 Main issues

This pricing strategy comes from the need to find an economically equitable allocation for optimal circuit investments of the economically adapted network (EAN). In this case, nodal transmission prices can be derived from circuit prices depending on a pre-defined split of payments among generators and consumers.

This method requires that the energy regulatory authority supervise the determination of the EAN and the calculation of nodal transmission prices although the calculation process can be performed by the transmission companies or the system operator. One very important issue is the right determination of the optimal circuit capacities and therefore, the associated investment costs. Determination of the EAN is not an straight forward task because of the amount of data and operational simulations involved, including assumptions about the future like demand forecasting and its nodal distribution, and development of new generation power plants and their location. Demand growth rates in developed countries are usually very small (no more than 1%

per year) and then transmission networks are already developed and they do not require the construction of new lines or substations. In those cases the determination of an EAN on a yearly basis is quite acceptable. Nevertheless, demand growth rates in developing countries are high (5 to 8% per year) and then transmission networks are still under development. In those cases, the definition of the EAN must involve a long term period of 7 to 10 years and consider the economies of scale provided by transmission assets over a long term period.

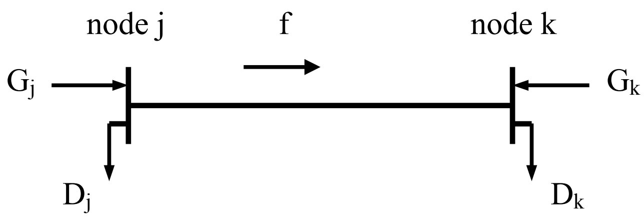
5.2 Transmission pricing based on an EAN

The proposition consists of the allocation of the optimal circuit investment costs over users of the transmission network on the basis of the intact network flows on the EAN, following the basic principles developed by J. Mutale in a PhD research work at UMIST (Mutale, J., 2000).

5.2.1 Allocation of transmission costs

Going back to the example presented in section 3.6.1 for the two bus network of Figure 3-1, in Table 3-5 the optimal circuit price for line ‘j-k’ is equal to 17.0 £/MWh in period [0, To], when the flows are binding. This price multiplied by the optimal transmission capacity (607 MW) and time To (3,528 hr) is equal to the optimal investment cost of line ‘j-k’ (36,402 Thousand £). Allocation of circuit prices only to periods when flows are binding mean the application of *time-of-use pricing*. Allocation of circuit prices to nodes mean the application of *location-specific pricing*. Therefore once circuit prices are allocated to nodes the resultant transmission prices are both location and time-of-use specific.

Allocation of circuit prices to nodal prices and therefore among generation and demand users can be performed by defining a reference node and using sensitivity factors. By definition an incremental change at injection at any node will be compensated by an equal and opposite injection at the reference node, hence the nodal price at the reference node is zero. Figure 5-1 shows the simplified version of the two bus network of Figure 3-1 and the definition of the sensitivity factors of power flow ‘f’ to the injection at nodes ‘j’ or ‘k’. For example if node ‘k’ is chosen as the reference, then an incremental change in injection at node ‘j’ will result in an increase on power flow ‘f’. Therefore the sensitivity factor of flow ‘f’ to the injection at node ‘j’ is equal to 1 and the circuit price of 17.0 £/MWh is allocated to node ‘j’ as a positive nodal transmission price. Thus generation G_j pays the nodal transmission price for every MWh injected to the network and demand D_j is paid the same nodal price for every MWh withdrawn from the network. In this case generation G_k and demand D_k do not pay transmission charges.



Sensitivity factor of flow *f* to the injection G_j at node ‘j’: $\dfrac{\partial f}{\partial G_j} > 0$

Sensitivity factor of flow *f* to the injection G_k at node ‘k’: $\dfrac{\partial f}{\partial G_k} < 0$

Figure 5-1: Allocation of circuit prices using sensitivity factors

If node ‘j’ is chosen as the reference, the sensitivity of flow ‘f’ to injection at node ‘k’ is negative because an increase in injection at node ‘k’ will result in a reduction in flow ‘f’. Therefore, the nodal transmission price at node ‘k’ is negative and equal to -17.0 £/MWh. However, using sensitivity factors the nodal transmission prices and charges to users depend on the choice of the reference node but the total transmission revenue is independent of the choice.

Another way to allocate the circuit prices is to split the transmission investment costs among generation and demand, for example 50%:50%. The nodal transmission prices np_j and np_k at nodes ‘j’ and ‘k’ respectively that result in a split φ_g over generators of the total transmission revenue (TTR) of the EAN can be found by solving equations (5-1) and (5-2) below.

$$np_j \cdot \int_0^{To} g_j(t)dt + np_k \cdot \int_0^{To} g_k(t)dt = \phi_g \cdot TTR \tag{5-1}$$

$$-np_j \cdot \int_0^{To} d_j(t)dt - np_k \cdot \int_0^{To} d_k(t)dt = (1-\phi_g) \cdot TTR \tag{5-2}$$

Table 5-1 presents the nodal transmission prices to use in period [0, To] for two choices of the reference node and for a 50%:50% split of the transmission revenue among generation and demand, using data from Table 3-2.

Table 5-1: Nodal transmission prices for different allocation criteria

	Reference at node 'j'	Reference at node 'k'	Split 50% generation, 50% demand
np_j (£/MWh)	0	17.0	7.7
np_k (£/MWh)	-17.0	0	-9.3
$np_j - np_k$ (£/MWh)	17.0	17.0	17.0

In summary, the results are coincident with the signals given by nodal transmission prices determined according to LRMC for the EAN in section 3.6.3. Only demand D_k pays the transmission cost if the reference node is set at node 'j' or only generator G_j pays if the reference node is set at node 'k'. Finally transmission cost is shared by generator G_j and demand D_k when a 50%:50% split is set.

Knowing the actual contribution of generators and consumers on the transmission investment cost of the EAN is a question that could have been answered positively if Kirchhoff Voltage Law (KVL) does not exist. However KVL impedes the right allocation of transmission costs via LRMC and therefore a market allocation among generation and demand cannot be found in meshed networks. In consequence a fair 50%:50% split among generation and demand will be considered in the method.

5.2.2 Formulation of the method

The optimal capacity F_i^{max} of every branch 'i' of the transmission network is determined as a result of the solution of the long term optimisation problem that minimised transmission investment costs plus generation operational costs of the power system. Therefore transmission investment costs of each branch, intact and contingent power flows and the optimal generation despatch in each demand period are known.

The pricing concept of *time-of-use* is considered in the method via the definition of a threshold factor β, to look for binding conditions on each branch 'i' with a flow $f_i(t)$ in a demand period 't':

$$\begin{aligned} &\text{If } |f_i(t)| \geq \beta \cdot F_i^{max} \Rightarrow f_i^{'}(t) = f_i(t); \\ &\qquad\qquad f_i^{'}(t) = 0 \ \text{ in all other cases} \end{aligned} \tag{5-3}$$

While closer to 100% is factor β the binding flows are closer to the transmission capacity F_i^{max}. Figure 5-2 shows a duration curve of flow $f(t)$ in a branch and threshold factor β.

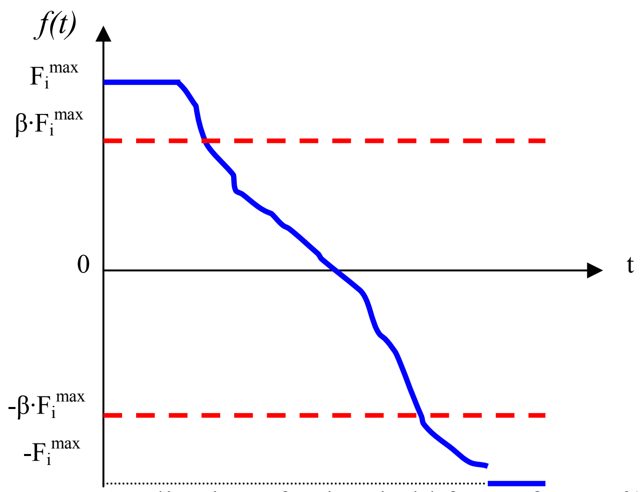


Figure 5-2 Application of a threshold factor β over $f(t)$

The maximum flows per branch of the intact or any contingent network in each period that are binding according to condition (5-3) are stored in a matrix arrangement.

A security factor $SF_i(t)$ for branch 'i' in period 't' is defined in order to adequate circuit prices for valuation with the intact flows of the EAN.

$$SF_i(t) = \frac{F_i^{max}}{f_i(t)} \quad (\text{for } f_i(t) \neq 0) \tag{5-4}$$

where:

F_i^{max} : optimal capacity of branch 'i'

$f_i(t)$: intact flow of branch 'i' in period 't'

Then the optimal circuit prices $cp_i(t)$ for branch 'i' in period 't' are defined as follows:

$$cp_i(t) = \frac{a_i \cdot l_i}{\sum_{i=1}^{NBR} nh_i} \cdot SF_i(t) \tag{5-5}$$

where:

a_i : annuitised investment factor of branch i (£/MW-km-year)

l_i : length of branch i (km)

$SF_i(t)$: security factor for branch 'i' in period 't'

nh_i : sum of hours in the periods when flows are binding for a branch 'i'

The definition of *location-specific* prices is determined via the calculation of nodal transmission prices $np_k(t)$ at node 'k' in period 't', using sensitivity factors:

$$np_k(t) = \sum_{i=1}^{NBR} cp_i(t) \cdot h_{ki}^{I} \tag{5-6}$$

where h_{ki}^{I} are elements of the sensitivity matrix H for the intact network I:

$$[H] = [Y_d] \cdot [A^T] \cdot \begin{bmatrix} 0 & 0 \\ 0 & [Y_{bus}^r]^{-1} \end{bmatrix} \tag{5-7}$$

In the calculation of the sensitivity matrix of equation (5-7) it is necessary to define a reference node or slack bus. The price at this node is zero. Therefore a shift on nodal transmission prices will be determined in order to split the transmission costs among generation and demand, as it was explained in section 5.2.1.

$$np_k^{sh}(t) = np_k(t) - \delta(t) \tag{5-8}$$

where:

$np_k^{sh}(t)$: shifted nodal transmission prices at node 'k' in period '*t*'

$np_k(t)$: nodal transmission prices at node 'k' in period '*t*'

$\delta(t)$: shift in nodal transmission prices in period '*t*' to obtain a desired split

The calculation of the shift depends on the definition of a split of payments among generation and demand. The split of payments to generators $\varphi_g(t)$ in period '*t*' is calculated as follows:

$$\phi_{\mathrm{g}}(t) = \frac{\sum_{k=1}^{NBUS} (np_k(t) - \delta(t)) \cdot g_k(t)}{\sum_{k=1}^{NBUS} np_k(t) \cdot (g_k(t) - d_k(t))} \tag{5-9}$$

where:

$g_k(t)$: generation despatch at node 'k' in period '*t*'

$d_k(t)$: demand at node 'k' in period '*t*'

$NBUS$: number of nodes

Denominator of equation (5-9) corresponds to the total transmission revenue $TTR(t)$ in period '*t*', calculated with nodal transmission prices:

$$TTR(t) = \sum_{k=1}^{NBUS} np_k(t) \cdot (g_k(t) - d_k(t)) \tag{5-10}$$

Solving equations (5-9) and (5-10), the shift in nodal transmission prices in period '*t*' is calculated as follows:

$$\delta(t) = \frac{\sum_{k=1}^{NBUS} np_k(t) \cdot g_k(t) - \phi_g(t) \cdot TTR(t)}{\sum_{k=1}^{NBUS} g_k(t)} \tag{5-11}$$

In the tests that follow a split of payments among generators and demand of 50%:50% is considered (φ_g =50%).

5.2.3 Tests on a 3-bus network

The formulation of the problem to determine the EAN and the relevant data to develop the tests of the method were performed using the three bus network model described in section 4.5.1.1. The same example developed in section 4.5.1.2 is used to present the method.

Considering a threshold of 90% of the transmission capacity as definition of binding flows, Table 6 contains the sequence to derive circuit prices and circuit revenue.

Table 5-2: Binding flows and circuit price

Optimal Capacity (MW)

Line	Capacity
L12	208
L23	92
L31	117

Power Flows per Line (MW)

Line	Period 1	Period 2	Period 3
L12	196	208	150
L23	-92	-92	-50
L31	-104	-117	-100

Binding Flows per Line (MW)

Line	Period 1	Period 2	Period 3
L12	196	208	0
L23	92	92	0
L31	0	117	0
Nhours	720	2800	5240

Binding Hours per Period (Hours)

Period 1	Period 2	Period 3	Total
720	2800	0	3520
720	2800	0	3520
0	2800	0	2800

Circuit Prices (£/MWh)

Line	Period 1	Period 2	Period 3
L12	4.8	4.5	0.0
L23	-4.5	-4.5	0.0
L31	0.0	-5.7	0.0

Circuit Revenue (Thousand £)

Line	Period 1	Period 2	Period 3	Total
L12	678	2635	0	3313
L23	298	1159	0	1457
L31	0	1855	0	1855
Total	976	5649	0	6625

In this case circuit revenues have a perfect match with transmission investment on a line per line basis, shown in Table 4-3.

Finally Table 5-3 shows the nodal transmission prices derived from the EAN and Table 5-4 presents nodal charges to serve as revenues to pay transmission investment costs of the EAN. This method always makes a perfect match between transmission investments and revenues on a line per line basis.

Table 5-3: Nodal transmission prices derived from the EAN

G - D (MW)

Node	Period 1	Period 2	Period 3
1	300	325	250
2	-288	-300	-200
3	-12	-25	-50

Power Flows = [H] x [G-D] (MW)

Line	Period 1	Period 2	Period 3
L12	196	208	150
L23	-92	-92	-50
L31	-104	-117	-100

[H]T Matrix

		Line	
Node	1	2	3
1	0.000	0.000	0.000
2	-0.667	0.333	0.333
3	-0.333	-0.333	0.667

Nodal Prices [H]T x [Cp]

Node	Period 1	Period 2	Period 3
1	0.000	0.000	0.000
2	-4.709	-6.410	0.000
3	-0.096	-3.786	0.000

Table 5-4: Nodal revenues to pay transmission investment costs

Nodal Revenue (Thousand £)

Node	Period 1	Period 2	Period 3	Total
1	0	0	0	0
2	975	5384	0	6359
3	1	265	0	266
Total	976	5649	0	6625

5.2.4 Tests on the IEEE 24-bus network

The formulation of the problem to determine the EAN and the relevant data to develop the practical tests of the method were performed using the IEEE 24 bus network model described in section 4.5.2.1. A test for five demand periods and a threshold of 90% to define binding flows was developed in order to compare the results with those presented for the SRMC method in section 4.5.2.2. The complete results are included in Appendix

C. Table 5-5 presents the valuation of nodal transmission charges on generation and demand sides showing the 50%:50% allocation.

Table 5-5: Generation and demand payments

Node	Generation (Thousand £)	Demand (Thousand £)	
1	55.5	-290.6	
2	36.3	-264.7	
3	0.0	-322.1	
4	0.0	-392.6	
5	0.0	-306.6	
6	0.0	-770.4	
7	16.6	-736.7	
8	0.0	-1089.8	
9	0.0	-756.9	
10	0.0	-836.4	
11	0.0	0.0	
12	0.0	0.0	
13	143.4	143.1	
14	0.0	-175.7	
15	179.0	443.0	
16	184.7	57.8	
17	0.0	0.0	
18	227.9	220.6	
19	0.0	23.8	
20	0.0	-85.5	
21	2077.0	0.0	
22	1726.9	0.0	
23	492.4	0.0	
24	0.0	0.0	
Total	5139.6	-5139.6	10279.2

A sensitivity analysis to probe the impact of the threshold, to define flows that are binding, on time-of use allocation of transmission revenues is presented in Table 5-6. Threshold values between 50% and 100% were chosen and the temporal distribution of circuit revenues was determined. For a threshold of 100% (only flows equal to the optimal capacity are binding) the temporal distribution of the transmission revenues is similar to the distribution of LRMC transmission revenues for the EAN (taken from Table 4-8). On the other side, for a threshold of 50% (flows over 50% of the optimal capacity are binding) the temporal distribution of the revenues is similar to the time distribution per period, indicating that for a threshold less than 50% transmission prices lose the time-of-use signal.

Table 5-6: Distribution of payments by period depending on threshold

			Demand Period					
			1	2	3	4	5	Total
LRMC revenue		(Th.£)	972.7	312.8	5995.0	178.2	2820.4	10279.2
		(%)	9%	3%	58%	2%	27%	100%
Duration per period		(Hours)	287	1724	2486	2661	1578	8736
		(%)	3%	20%	28%	30%	18%	100%
Circuit revenue		(Th.£)						10279.2
Distribution (%)	Threshold	100%	9%	5%	61%	5%	20%	100%
		90%	7%	8%	63%	11%	11%	100%
		80%	5%	22%	32%	34%	7%	100%
		70%	6%	21%	31%	32%	10%	100%
		50%	3%	20%	29%	30%	18%	100%

Some special case studies will be presented in the next section to probe the robustness of the method.

5.3 Case studies on the IEEE 24-bus network

A series of case studies on the IEEE 24-bus network were performed considering fifty demand periods and a threshold of 90% to define binding flows. The studies show the robustness of the proposed method using the C-programme subroutine working over a large network, similar to a real one.

Topology and parameters of the IEEE 24-bus network, generation and demand data considered in the case studies are given in Appendix C. The power system has 31 generators, 38 branches and a peak demand of 2,850 MW and an 'N-1' security criteria is considered in the studies.

5.3.1 Network cost recovery

Transmission revenue for the EAN covers exactly the investment cost of the network as it is demonstrated in Table 5-7. For over-invested networks a recovery in excess of the EAN revenue is permitted because there are benefits derived of lower generation operational costs. For example, for a 50% over-capacity in the network only a 1.5% additional revenue is obtained.

Table 5-7: Transmission revenue for the EAN and an over-invested network

Transmission Capacity / Optimal Capacity	Total Operation and Investment Cost (Thousand £)	Operation Costs (Thousand £)	Transmission Investment Cost (Thousand £)	Transmission Revenue (Thousand £)	Transmission revenue / Optimal Revenue
1	134,748.9	124,478.7	10,270.3	10,270.3	1.000
1.1	135,490.1	124,192.8	11,297.3	10,381.4	1.011
1.2	136,505.2	124,180.8	12,324.3	10,404.1	1.013
1.5	139,580.9	124,175.5	15,405.4	10,419.3	1.015

Table 5-8 presents the allocation of the EAN costs among generators and consumers.

Table 5-8: Generation and demand payments for a 50%:50% split

Node	Generation (Thousand £)	Demand (Thousand £)	
1	77.8	-308.6	
2	-25.4	-283.6	
3	0.0	-325.1	
4	0.0	-369.8	
5	0.0	-305.2	
6	0.0	-738.0	
7	-45.4	-831.7	
8	0.0	-1072.4	
9	0.0	-726.0	
10	0.0	-804.9	
11	0.0	0.0	
12	0.0	0.0	
13	59.5	197.1	
14	0.0	-183.1	
15	135.7	401.3	
16	114.4	45.4	
17	0.0	0.0	
18	113.5	137.8	
19	0.0	64.6	
20	0.0	-32.8	
21	1992.0	0.0	
22	1667.2	0.0	
23	1045.8	0.0	
24	0.0	0.0	
Total	5135.2	-5135.2	10270.3

5.3.2 Robust and weak networks

The same IEEE 24-bus network was slightly modified in order to create a robust or a weak network compared to the reference network and evaluate the transmission pricing method on those cases.

Looking at the network topology (Figure C-1 of Appendix C), a robust transmission network can be obtained by moving generators G3, G4, G5 and G6 from nodes 1 and 2 to node 21. In that way the demand area formed by nodes 1 and 2 will require transmission capacity reinforcements and the generation area formed by nodes 18, 21 and 22 will also require reinforcements to evacuate the additional generation injection.

In the same way, a weak transmission network can be obtained by moving generators G24, G25, G26 and G27 from node 22 to node 6 (2 units) and node 4 (2 units). In that way the generation area formed by nodes 18, 21 and 22 will not require a bigger capacity and the demand area formed by nodes 2, 4 and 6 will be supplied by the additional generation injection, reducing transmission demands.

Table 5-9 presents the impact of the movements to obtain a robust or weak network on transmission investment costs and revenues of the corresponding EAN. As a result of the changes the robust network has an investment cost 15.2% higher than the reference network and the weak network has an investment cost 22.9% lower than the reference network. For each case transmission revenues are equal to investment costs of the corresponding EAN.

Table 5-9: Transmission revenue for the reference, robust and weak networks

Transmission Network	Total Operation and Investment Cost (Thousand £)	Operation Costs (Thousand £)	Transmission Investment Cost (Thousand £)	Transmission Revenue (Thousand £)	Transmission investment / Reference investment
Reference	134,748.9	124,478.7	10,270.3	10,270.3	1.000
Robust	136,209.0	124,375.4	11,833.5	11,833.5	1.152
Weak	132,392.2	124,471.2	7,921.0	7,921.0	0.771

Figure 5-3 shows the optimal transmission capacity by branch for the robust and weak networks compared to the capacity of the reference network and Table 5-10 presents the allocation of transmission costs of the EAN among generators and consumers.

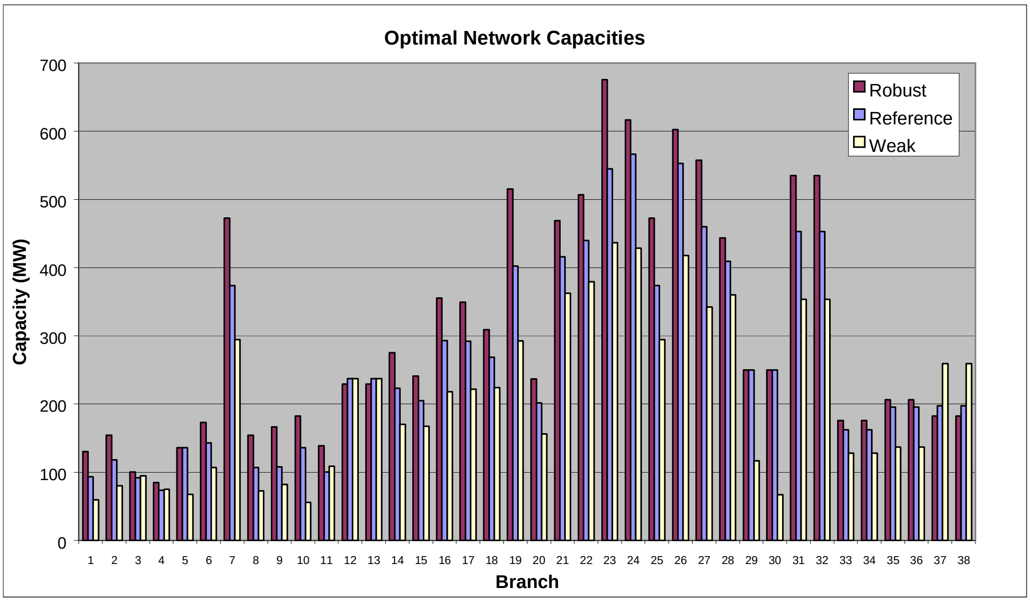


Figure 5-3 Optimal transmission capacity for a robust and weak network

Table 5-10: Generation and demand payments for a 50%:50% split

Robust network:

Node	Generation (Thousand £)	Demand (Thousand £)	
1	-28.7	-1046.1	
2	-43.8	-1014.6	
3	0.0	-623.6	
4	0.0	-553.4	
5	0.0	-446.7	
6	0.0	-258.1	
7	-23.3	-789.3	
8	0.0	-1160.8	
9	0.0	-961.7	
10	0.0	-761.8	
11	0.0	0.0	
12	0.0	0.0	
13	44.5	110.8	
14	0.0	-121.2	
15	360.4	687.1	
16	347.9	162.7	
17	0.0	0.0	
18	801.6	702.4	
19	0.0	310.4	
20	0.0	-152.9	
21	3130.7	0.0	
22	1886.0	0.0	
23	-558.6	0.0	
24	0.0	0.0	
Total	5916.7	-5916.7	11833.5

Weak network:

Node	Generation (Thousand £)	Demand (Thousand £)	
1	-86.2	-320.5	
2	28.8	-276.5	
3	0.0	-148.5	
4	-347.0	-190.0	
5	0.0	-300.5	
6	-540.2	-491.9	
7	-36.4	-814.2	
8	0.0	-1054.2	
9	0.0	-713.5	
10	0.0	-783.9	
11	0.0	0.0	
12	0.0	0.0	
13	94.2	458.2	
14	0.0	-82.6	
15	214.4	621.0	
16	155.6	82.5	
17	0.0	0.0	
18	-630.0	-108.0	
19	0.0	106.8	
20	0.0	55.3	
21	2860.1	0.0	
22	713.3	0.0	
23	1533.8	0.0	
24	0.0	0.0	
Total	3960.5	-3960.5	7921.0

5.3.3 Impact of security in network design

A study was performed to analyse the impact of security of service in the investment cost of the EAN. The reference case study of section 5.3.1 was developed to determine network optimal capacity with 'N-1' criteria. The next step was the development of a case study without considering 'N-1' security criteria, so capacities for pure transportation arise from this study. It is important to warn that all lines except line 11 were considered in the analysis. Line 11 cannot be included because of its radial characteristic.

Figure 5-4 shows the over-capacity produced by the application of 'N-1' security criteria in network design. Investment cost of the network without 'N-1' criteria is equal to £6.1 million and this cost can be associated to pure transportation. Investment cost using the 'N-1' criteria is equal to £10.3 million, therefore £4.2 million are the over-investment cost associated to system security, equivalent to 41% of the total investment cost. The evaluation of the over-capacity investment cost is presented in Table 5-11.

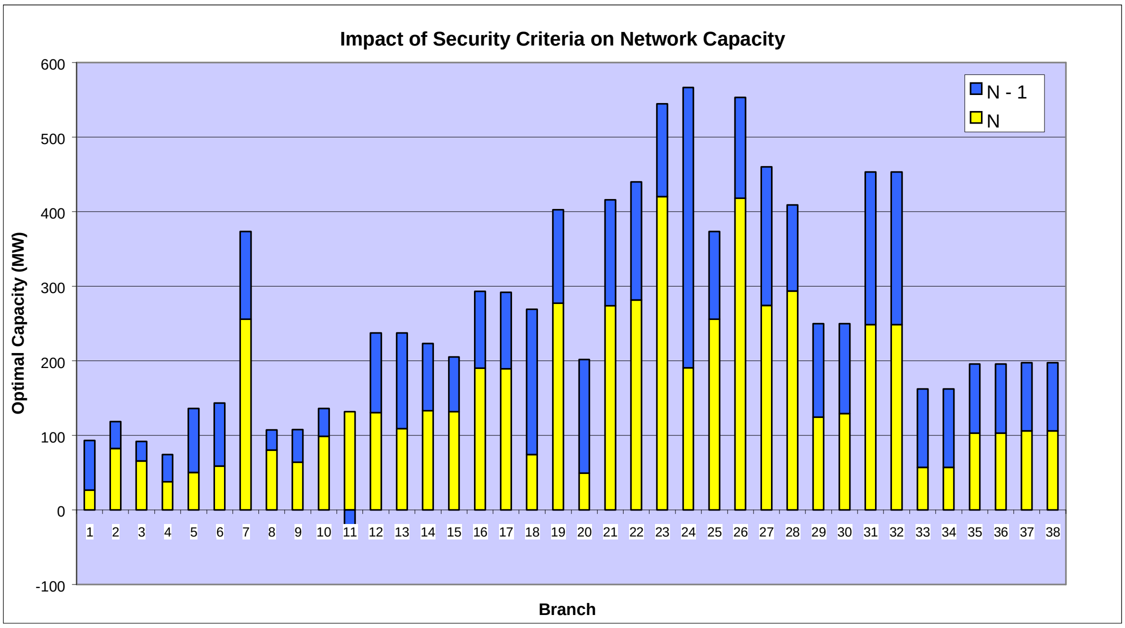


Figure 5-4 Optimal transmission capacity with and without 'N-1' criteria

Transportation costs can be allocated 50%:50% among generation and demand but security costs must be allocated 100% to demand because consumers have a higher willingness to pay for security due to the deeper impact of outages, as it was discussed in section 3.7.2. Table 5-11 presents the resulting 30%:70% split among generation and demand respectively and Table 5-12 shows the corresponding payments.

Table 5-11: Investment costs and allocation among generators and consumers

Allocation of transmission investment costs			Thousand £	
	Investment for electricity transportation		**6062.3**	
	Allocation:	50% generation	3031.2	
		50% demand	3031.2	
	Investment for security of service		**4207.9**	
	Allocation:	100% demand	4207.9	
	Total allocation			
		Generation	**3031.2**	**30%**
		Demand	**7239.1**	**70%**
		Total	**10270.2**	

Table 5-12: Generation and demand payments for a 30%:70% split

Node	Generation (Thousand £)	Demand (Thousand £)	
1	44.3	-386.5	
2	-76.8	-353.5	
3	0.0	-454.8	
4	0.0	-423.1	
5	0.0	-356.4	
6	0.0	-836.0	
7	-53.8	-921.8	
8	0.0	-1195.6	
9	0.0	-852.1	
10	0.0	-945.4	
11	0.0	0.0	
12	0.0	0.0	
13	45.9	6.1	
14	0.0	-322.9	
15	31.7	172.9	
16	31.0	-26.6	
17	0.0	0.0	
18	-334.8	-102.2	
19	0.0	-65.9	
20	0.0	-125.1	
21	1541.3	0.0	
22	1385.5	0.0	
23	467.3	0.0	
24	0.0	0.0	
Total	3081.5	-7188.9	10270.3

Generation and demand charges for use of the network can be transformed into nodal transmission prices by dividing the corresponding charges by the electricity injection or withdraw at the respective node, taken from the optimal despatch and demand for the EAN. The comparison of nodal transmission prices for a 50%:50% split generation-demand (based on payments shown in Table 5-8) and 30%:70% split generation-demand (based on payments shown in Table 5-12) is given in Table 5-13.

Table 5-13: Comparison of nodal transmission prices for 50/50% and 30/70% split

50% generation- 50% demand split

Node	Generation (£/MWh)	Demand (£/MWh)
1	0.33	-0.53
2	-0.07	-0.54
3	0.00	-0.33
4	0.00	-0.92
5	0.00	-0.79
6	0.00	-1.00
7	-1.10	-1.23
8	0.00	-1.16
9	0.00	-0.76
10	0.00	-0.76
11	0.00	0.00
12	0.00	0.00
13	0.72	0.14
14	0.00	-0.17
15	0.20	0.23
16	0.18	0.08
17	0.00	0.00
18	0.03	0.08
19	0.00	0.07
20	0.00	-0.05
21	0.57	0.00
22	0.76	0.00
23	0.24	0.00
24	0.00	0.00
Total	0.33	-0.33

30% generation- 70% demand split

Node	Generation (£/MWh)	Demand (£/MWh)
1	0.21	-0.66
2	-0.23	-0.67
3	0.00	-0.47
4	0.00	-1.05
5	0.00	-0.93
6	0.00	-1.13
7	-1.04	-1.36
8	0.00	-1.29
9	0.00	-0.90
10	0.00	-0.89
11	0.00	0.00
12	0.00	0.00
13	0.64	0.00
14	0.00	-0.31
15	0.05	0.10
16	0.04	-0.05
17	0.00	0.00
18	-0.10	-0.06
19	0.00	-0.07
20	0.00	-0.18
21	0.44	0.00
22	0.63	0.00
23	0.11	0.00
24	0.00	0.00
Total	0.20	-0.46

In both cases the total transmission price (generation minus demand) on an annual base is equal to only 0.66 £/MWh. This value is less than 5% of the energy market cost in the IEEE 24-bus system, given in Table 4-7 for five demand periods. It is important to indicate that a positive price for generation means a cost and analogously a negative price for demand also means a cost, because demand is evaluated with a negative sign.

Figures 5-5 and 5-6 present graphically the nodal transmission prices.

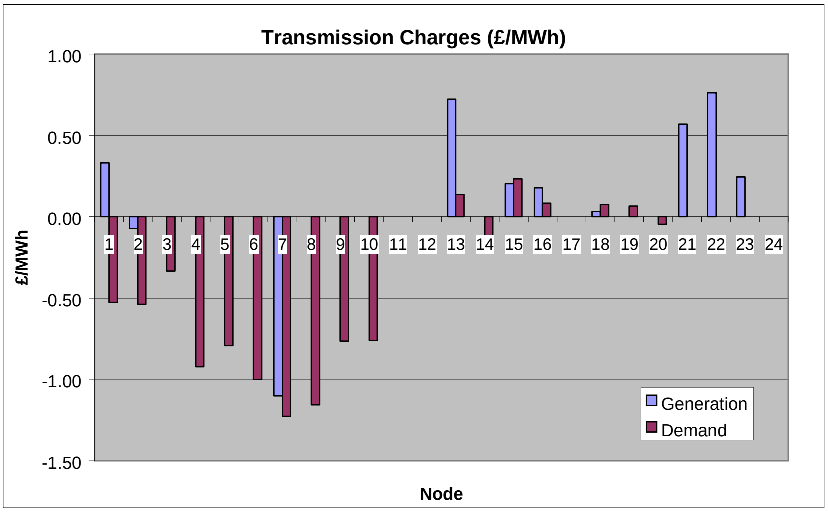


Figure 5-5 Nodal transmission prices for a 50/50% split generation/demand

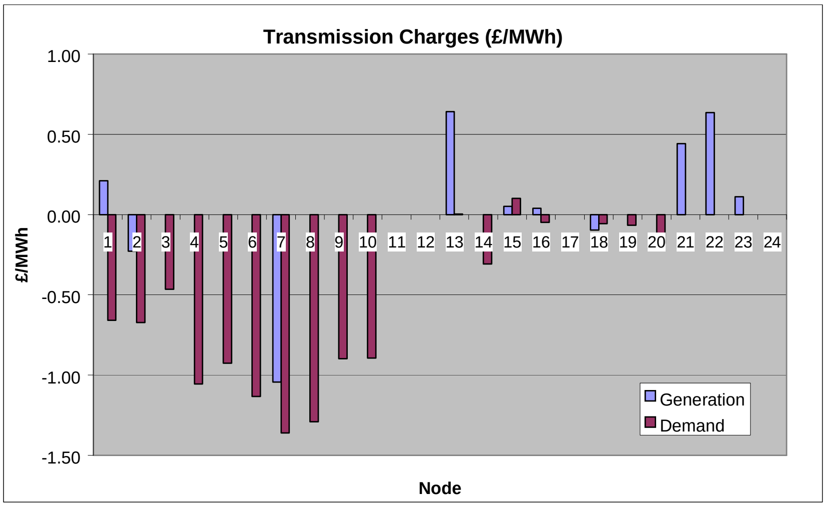


Figure 5-6 Nodal transmission prices for a 30/70% split generation/demand

In summary, the method has probed to be an efficient transmission access pricing methodology that allow the recovery of transmission investment costs. For that reason, transmission pricing based on the concept of "economically adapted network" (EAN) is recommended. Prices derived from the EAN have the advantage to be tuned with the maximum revenue allowed to the owner of transmission assets and facilitate the optimal allocation of transmission costs among users of the network.

5.4 Implementation on a real system: England & Wales and Chile cases

Both cases were pioneers in electricity deregulation in the 80's and both are currently fronting a severe review of the transmission pricing scheme in use. England and Wales scheme is evolving from a transmission pricing scheme without locational signals in the short term to a market-based scheme of access rights where an additional charge will be required to complete the revenue of the TO (NGC). Chile is evolving from a scheme with powerful short term signals based on nodal pricing but unable to find a rule to allocate the costs of the network among the users (today only focus on generation companies).

5.4.1 Implementation in England and Wales

The proposed method could be used as part of the NETA proposals to determine the TNUoS charges as an option to the ICRP method. The proposed method has the virtue to consider the spatial and temporal allocation of costs in perfect tune with marginal cost principles and therefore sending right signals to the users regarding the costs they impose on the network in the long term.

5.4.2. Implementation in Chile

The proposed method could be used by the Chilean National Energy Commission to replace the current method of area of influence and pro-rata to calculate transmission tolls. Moreover it means the definition of a unified transmission toll (replacing the current basic and additional tolls) that will be allocated over generators and consumers. On that way, regulated nodal prices calculated as the transference price among generation companies and distribution companies to supply consumers with a demand below 2 MW should be complemented with a transmission charge to recover the payments from consumers to the owners of the transmission assets.

CHAPTER 6

Conclusion

Summary

This chapter presents the main conclusions, achievements and contributions of this research and recommends topics for future research.

6.1 Main conclusions

Theoretical and practical experiences in transmission pricing arise to the conclusion that there is no a global optimal method for pricing the use of the electricity transmission network. SRMC are well known optimal prices in the energy market nevertheless they are not able to remunerate the investment costs of the transmission network. Therefore a second best solution must be defined. Transmission pricing based on the concept of "economically adapted network" (EAN) has probed to be an efficient transmission access pricing method that allow the recovery of transmission investment costs. Prices derived from the EAN have the advantage to be tuned with the maximum revenue allowed to the owner of transmission assets and also those prices facilitate the optimal allocation of transmission costs among users of the network.

In the process of allocation of transmission costs it is important to recognise that both generation and demand users affect the dimensioning of the transmission network and therefore they must pay for the use of the existent assets. In meshed networks where it is not possible to identify transmission facilities fully used by generators or consumers, the allocation of transmission costs must be shared in equal parts by both parties. Determination of allocation according to the behaviour of the energy market nodal prices is not a straightforward process in meshed networks due to the complex interactions derived from the physical constraint associated to the Kirchhoff Voltage Law (KVL). Therefore, the allocation of transmission costs associated to transportation of electricity can be shared 50%:50% among generators and consumers. Additional investments derived of the application of security of service criteria (i.e. "N-1") must be allocated to consumers only. Security of service is required mostly by demand side due to the higher economic impact of outages on consumers rather than generators. Thus, consumers must pay most of transmission over-capacity destined to minimise the impact of outages in the transmission network.

Transmission prices to cover the investment costs of the existent assets must be regulated because of the monopoly characteristic of the transmission business and payments must be compulsory to avoid free rider attitudes from participants in the energy market. However the determination of the EAN is not an straight forward task because of the amount of data and operational simulations involved, including assumptions about the future like demand forecasting and new generating plants definition and location. Small demand growth rates in developed countries mean transmission networks already developed and there development of new lines or substations is not required. In those cases the determination of an EAN on a yearly basis is quite acceptable. Nevertheless, high demand growth rates in developing countries mean transmission networks under constant development. In those cases, the definition of the EAN must involve a long term period (i.e. 10 years) and considering economies of scale provided by transmission assets over that period.

Transmission pricing must be consistent with pricing in the energy market. Using system marginal pricing (SMP) plus congestion management techniques to solve transmission constraints or using nodal short run marginal costs (SRMC) in the energy market (pool-based or bilateral contracts) depend on the interest of the regulatory authority to let market participants to solve congestion by themselves (using SRMC) or with helping of the system operator (using SMP plus congestion management). Anyway SRMC surplus derived from the energy market transactions must be allocated to market participants rather than transmission owners because of the perverse incentive to cause congestion and increase the value of the SRMC surplus. Financial transmission rights (FTR) have probed to be an efficient market way to allocate the SRMC surplus among participants in the energy market.

Price differences between nodes as a result of SRMC application are not the right way to pay for the use of the transmission network. SRMC do not have any relation to transmission investments and moreover, in real networks with over-capacity the SRMC surplus can be very small or equal to zero. A better approach to define transmission prices is the use of long run marginal costs (LRMC) based on an economically adapted network. Nevertheless in meshed networks LRMC revenues follow Kirchhoff Voltage Law but transmission investments do not. Then there is not a perfect match between LRMC revenues and investments for the optimal network on a line per line basis.

The use of SRMC for transmission pricing may result in under-capacity in the transmission network, causing severe congestion and therefore breaking the energy market into isolated zones. The benefits of a robust grid go to every participant in the energy market, particularly consumers, due to a more competitive scenario and then less options to exercise market power by any participant. In summary, a cost-based method like nodal transmission prices derived from the EAN is preferred to a value-based method for transmission pricing.

Development of the transmission network can be performed on a market base only in particular situations. Two types of transmission expansion projects can be identified. One type of project refers to new transmission facilities or upgrading on existent facilities that affect a large amount of users and generally are linked to global security of service. In that case it is very difficult if not impossible to get a negotiated agreement with users in time to expand network capacity and regulatory support is necessary. Other type of project where there is only one or few users can be done based on market forces because individual users are capable to measure the impact of the project in the energy market. Regulatory participation in investment decisions would not be necessary if market participants work in a co-operative more than a competitive way.

6.2 Achievements and contributions of this research

A joint analysis of transmission open access schemes and its interaction with the energy market was presented, facilitating the selection of an appropriate method to price the use of transmission networks. A unified methodology to analyse the energy and access market was developed in order to facilitate the analysis of different pricing strategies. Three different models were developed (analytical 2-bus, 3-bus network and IEEE 24-bus network) that provide a framework to evaluate different pricing schemes and investment development in the energy and access markets.

The link between short and long term issues in electricity transmission was extensively analysed, more specifically in relation to the allocation of costs of the existing network and development of investments to increase the capacity of the network. In that sense the foundations of pricing and investment in electricity transmission have been reviewed providing a solid reference for future deregulation processes.

The main limitations of the short run marginal cost theory to price the use of the transmission network was discovered. Particularly in meshed transmission networks SRMC revenues follow Kirchhoff Voltage Law but investments do not. Therefore there is not a perfect match between SRMC (nor LRMC) revenues and investments for the optimal network on a line per line basis.

The analysis were developed implementing C-written routines to calculate SRMC and LRMC in a multi-node and multi-period computer programme that determines an economically adapted network of a large power system. The routines will allow UMIST to have a powerful tool to evaluate the behaviour of the energy market and determine locational marginal prices in the same way prices will be discovered in a competitive market.

The recommended transmission pricing method can be applied calculating an economically adapted network (EAN) or determining a regulated price control based on net replacement values (NRV) of the existing assets in the network and then using the allocation technique to determine time-of-use/location specific nodal transmission prices.

6.3 Recommendations for future research

From the regulatory point of view a definition of the short run costs of not supplied energy could be an efficient way to send market signals regarding the value of security for users. In that way a deterministic security criteria like "N-1" would be replaced by a market based approach that justifies over-investments in transmission capacity in order to provide the level of security required by consumers. This way could be the base to define security driven investments in transmission.

In developing countries the determination of the economically adapted network require the development of a new model that considers a long term period (i.e. 10 years), take into account economies of scale in transmission investments and uncertainties regarding the location of new generation facilities and new demand. Particularly difficult is the determination of the EAN in power systems with an important hydro-power generation (i.e. Brazil, Chile, Norway) due to the stochastic nature of the production costs linked to the optimal reservoir management.

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Appendix A

Nodal SRMC on a Transmission Network

A1. Objective

The objective of this appendix is the presentation of two methods to calculate short run marginal costs (SRMC) by node on a transmission network, considering transmission capacity and security constraints.

A2. Introduction

In a competitive market like electricity, SRMC represent the optimal price to interchange energy among producers and users, minimising the system operating costs and maximising social welfare. In electricity deregulated markets, based on bilateral agreements (not pool based), SRMC are a very good reference to discover the value of electricity at different locations on the transmission network. In absence of market power, prices must tend to SRMC at every location on the network. Therefore, it is worth for generation and supply companies bidding in a new bilateral energy market to discover the locational value of electricity and design commercial strategies to maximise profits in that new environment.

In this Appendix two methods to calculate SRMC are presented on a 3-node lossless network.

A3. Nodal SRMC calculations using GGDF

Figure A-1 presents a 3-bus network with three generators that supply nodal demand.

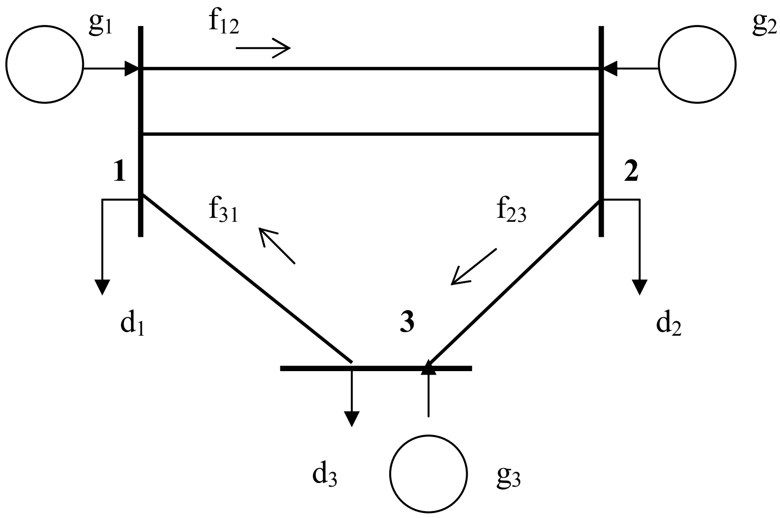

Figure A-1: Three bus network

Variable operation costs of G_1, G_2 and G_3 are c_1, c_2 and c_3 respectively. Power flows by the transmission lines L_1, L_2 and L_3 are f_{12}, f_{23} and f_{31} respectively.

Using generalised generation distribution factors or GGDF (Ng, W., 1981), the flows by the transmission lines can be written as:

$$f_l = \sum_{i=1}^{3} a_{li} \cdot g_i$$

Where a_{li} is the GGDF of the generator "i" on the line "*l*". Values of GGDF are dependent of the network topology, reactance and demand distribution.

By minimising the total operation costs of the system the calculation of the system marginal cost (λ) is performed.

The objective function is:

$$\text{Min} \sum_{i=1}^{3} c_i \cdot \mathrm{g_i}$$

subject to:

$$-g_i \le \text{-}\,\mathrm{Gmin_i} \qquad \mathrm{i}=1,2,3 \quad \text{(generators)}$$

$$g_i \le \mathrm{Gmax_i} \qquad \mathrm{i}=1,2,3 \quad \text{(generators)}$$

$$\sum_{i=1}^{3} a_{li} \cdot g_i \le \mathrm{Fmax_l} \qquad \mathrm{l}=1,2,3 \quad \text{(lines)}$$

$$-\sum_{i=1}^{3} a_{li} \cdot g_i \le \text{-}\,\mathrm{Fmax_l} \qquad \mathrm{l}=1,2,3 \quad \text{(lines)}$$

$$d \;\text{-} \sum_{i=1}^{3} g_i = 0 \qquad \text{(total demand, } d=\sum_{i=1}^{3} d_i\text{)}$$

Then,

$$\begin{aligned} Z = &\sum \mathrm{c_i} \cdot \mathrm{g_i} + \lambda \cdot (\mathrm{d} - \sum \mathrm{g_i}) + \sum \mu_i \cdot (g_i - G\max_i) + \sum \nu_i \cdot (-g_i + G\min_i) + \\ &+ \sum \tau_l \cdot (\sum a_{li} \cdot g_i - F\max_l) + \sum \gamma_l \cdot (-\sum a_{li} \cdot g_i + F\max_l) \end{aligned}$$

$$\frac{\partial Z}{\partial g_i} = \;0\; = c_i - \lambda + \mu_i - \nu_i + \sum (\tau_l - \gamma_l) \cdot a_{li} \qquad \mathrm{i}=1,2,3$$

And then, the system SRMC is:

$$\lambda = c_i + \mu_i - \nu_i + \sum (\tau_l - \gamma_l) \cdot a_{li}$$

Advancing into the calculation of SRMC by node, we must re-write the demand equation considering Kirchhoff Current Law (KCL) at every one of the 3 nodes as follows:

$$d_1 \,\text{-}\, \mathrm{g_1} + f_{12} - f_{31} = 0 \qquad (\lambda_1)$$

$$d_2 \,\text{-}\, \mathrm{g_2} - f_{12} + f_{23} = 0 \qquad (\lambda_2)$$

$$d_3 \,\text{-}\, \mathrm{g_3} + f_{31} - f_{23} = 0 \qquad (\lambda_3)$$

Then:

$$Z = \sum c_i \cdot g_i + \sum \mu_i \cdot (g_i - G\max_i) + \sum \nu_i \cdot (-g_i + G\min_i) + \sum \tau_l \cdot (\sum a_{li} \cdot g_i - F\max_l) +$$
$$+ \sum \gamma_1 \cdot (-\sum a_{li} \cdot g_i + F\max_l) + \lambda_1 \cdot (d_1 - g_1 + f_{12} - f_{31}) + \lambda_2 \cdot (d_2 - g_2 - f_{12} + f_{23}) +$$
$$+ \lambda_3 \cdot (d_3 - g_3 + f_{31} - f_{23})$$

$$\frac{\partial Z}{\partial g_1} = 0 = c_1 + \mu_1 - \nu_1 + \sum (\tau_l - \gamma_l) \cdot a_{l1} - \lambda_1 + \lambda_1 \cdot (\frac{\partial f_{12}}{\partial g_1} - \frac{\partial f_{31}}{\partial g_1}) + \lambda_2 \cdot (-\frac{\partial f_{12}}{\partial g_1} + \frac{\partial f_{23}}{\partial g_1}) +$$
$$+ \lambda_3 \cdot (\frac{\partial f_{31}}{\partial g_1} - \frac{\partial f_{23}}{\partial g_1})$$

But $\lambda = c_1 + \mu_1 - \nu_1 + \sum (\tau_l - \gamma_l) \cdot a_{l1}$

Then,

$$\frac{\partial Z}{\partial g_1} = 0 = \lambda + \lambda_1 \cdot (-1 + a_{11} - a_{31}) + \lambda_2 \cdot (-a_{11} + a_{21}) + \lambda_3 \cdot (a_{31} - a_{21})$$

$$\frac{\partial Z}{\partial g_2} = 0 = \lambda + \lambda_1 \cdot (a_{12} - a_{32}) + \lambda_2 \cdot (-1 - a_{12} + a_{22}) + \lambda_3 \cdot (a_{32} - a_{22})$$

$$\frac{\partial Z}{\partial g_3} = 0 = \lambda + \lambda_1 \cdot (a_{13} - a_{33}) + \lambda_2 \cdot (-a_{13} + a_{23}) + \lambda_3 \cdot (-1 + a_{33} - a_{23})$$

They also can be written as:

$$\lambda = \lambda_1 + a_{11} \cdot (\lambda_2 - \lambda_1) + a_{21} \cdot (\lambda_3 - \lambda_2) + a_{31} \cdot (\lambda_1 - \lambda_3)$$
$$\lambda = \lambda_2 + a_{12} \cdot (\lambda_2 - \lambda_1) + a_{22} \cdot (\lambda_3 - \lambda_2) + a_{32} \cdot (\lambda_1 - \lambda_3)$$
$$\lambda = \lambda_3 + a_{13} \cdot (\lambda_2 - \lambda_1) + a_{23} \cdot (\lambda_3 - \lambda_2) + a_{33} \cdot (\lambda_1 - \lambda_3)$$

However, $\lambda_2 - \lambda_1$ represents the SRMC difference between nodes 2 and 1 and it is equal to the sum of the Lagrange multipliers for the transmission constraints of Line 1 or $\tau_1 - \gamma_1$.

Then, $\lambda_2 - \lambda_1 = \tau_1 - \gamma_1$, $\lambda_3 - \lambda_2 = \tau_2 - \gamma_2$ and $\lambda_1 - \lambda_3 = \tau_3 - \gamma_3$.

Thus, the system SRMC is related to the nodal SRMC by the following equation:

$$\lambda = \lambda_i + \sum_{l=1}^{3} (\tau_l - \gamma_l) \cdot a_{li}$$

And the nodal SRMC at every node "i" can be calculated as:

$$\lambda_i = c_i + \mu_i - \nu_i = \lambda - \sum_{l=1}^{3} (\tau_l - \gamma_l) \cdot a_{li}$$

A4. Nodal SRMC calculations based on a SCOPF

Using a security constrained optimal power flow (SCOPF), nodal SRMC can also be calculated considering the Lagrange multipliers as an outcome of the optimisation process.

To introduce security constrained calculations we are going to add a new variable renaming the lines. Thus, as shown in Figure A-2, $f_1 = f_{12}^{c1}$, $f_2 = f_{12}^{c2}$, $f_3 = f_{31}$ and $f_4 = f_{23}$.

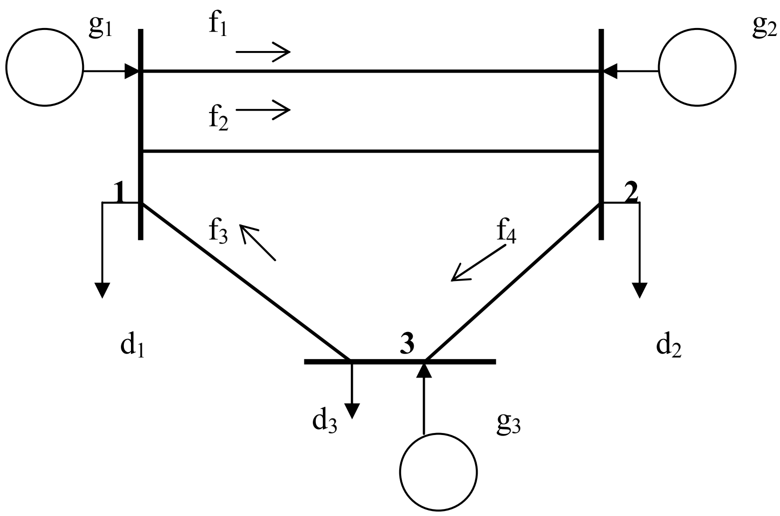

Figure A-2: Three bus network for SCOPF

Minimising the total operation costs of the system without considering the transmission capacity constraints, the problem can be written as:

$$\mathrm{Min} \sum_{i=1}^{3} c_i \cdot \mathrm{g_i}$$

subject to:

$$g_i \le \mathrm{Gmax_i} \qquad \mathrm{i} = 1,2,3 \quad \text{(generators)}$$

$$-g_i \le -\mathrm{Gmin_i} \qquad \mathrm{i} = 1,2,3 \quad \text{(generators)}$$

$$d - \sum_{i=1}^{3} g_i = 0 \qquad \left(\text{total demand, } d = \sum_{i=1}^{3} d_i\right)$$

As a result the power flows through the lines can be calculated (F_l^0), where the subscript "*l*" represents the line number and the superscript "0" means belonging to the unconstrained system.

Therefore, for the intact system (I) the transmission constraints can be written using the sensitivity coefficients h_{li}, representing the incremental change in power flow Δf_l in line "*l*" due to an incremental change in generation Δg_i at node "i".

$$h_{li} = \frac{\partial f_l}{\partial g_i} \quad \text{and their values are obtained from} \quad [\mathrm{H}] = [\mathrm{Y_d}] \cdot [A^T] \cdot [\begin{matrix} 0 & 0 \\ 0 & [Y_{bus}^r]^{-1} \end{matrix}]$$

Then, the constrained flows for the intact system (I) can be written as:

$$F_l^0 + \sum_{i=1}^{3} h_{li}^I \cdot (g_i - g_i^0) \le F\max_l$$

$$-F_l^0 - \sum_{i=1}^{3} h_{li}^I \cdot (g_i - g_i^0) \le -F\max_l \qquad \mathrm{l} = 1,\ldots 4$$

In the same way, for the contingent system (C) the transmission constraints can be written using the sensitivity coefficients h_{li} but they must be re-calculated according to the new network topology under the contingent condition, for example with line 1 out of service.

Then, the constrained flows for the contingent system (C) are:

$$F_l^I + \sum_{i=1}^{3} h_{li}^C \cdot (g_i - g_i^I) \le F\max_l$$

$$-F_l^I - \sum_{i=1}^{3} h_{li}^C \cdot (g_i - g_i^I) \le -F\max_l \qquad\qquad 1 = 1,...4$$

In this case, the augmented Lagrangian can be written as:

$$\begin{aligned} Z = {} & \sum c_i \cdot g_i + \lambda \cdot (d - \sum g_i) + \sum \mu_i \cdot (g_i - G\max_i) + \sum \nu_i \cdot (-g_i + G\min_i) + \\ & + \sum \tau_1^{\mathrm{I}} \cdot (\sum h_{li}^I \cdot (g_i - g_i^0) + F_l^0 - F\max_l) + \sum \gamma_1^{\mathrm{I}} \cdot (-\sum h_{li}^I \cdot (g_i - g_i^0) - F_l^0 + F\max_l) + \\ & + \sum \tau_1^{\mathrm{C}} \cdot (\sum h_{li}^C \cdot (g_i - g_i^I) + F_l^I - F\max_l) + \sum \gamma_1^{\mathrm{C}} \cdot (-\sum h_{li}^C \cdot (g_i - g_i^I) - F_l^I + F\max_l) \end{aligned}$$

And,

$$\frac{\partial Z}{\partial g_i} = 0 = c_i - \lambda + u_i - \nu_i + \sum (\tau_l^I - \gamma_l^I) \cdot h_{li}^I + \sum (\tau_l^C - \gamma_l^C) \cdot h_{li}^C$$

Then, the system SRMC is:

$$\lambda = c_i + u_i - \nu_i + \sum (\tau_l^I - \gamma_l^I) \cdot h_{li}^I + \sum (\tau_l^C - \gamma_l^C) \cdot h_{li}^C$$

And the SRMC at the node "i" is:

$$\lambda_i = c_i + u_i - \nu_i = \lambda \text{-} \sum_{\mathrm{S}}^{\mathrm{SYS}} \sum_{\mathrm{l}}^{\mathrm{L}} (\tau_1^{\mathrm{S}} - \gamma_l^S) \cdot h_{li}^S$$

Then, nodal SRMC can be obtained by calculating SRMC for the unconstrained system (λ) and subtracting the sum of the Lagrange multipliers associated to transmission constraints on every one of the system topologies evaluated in the SCOPF method.

Appendix B

Simulations on a 3-Bus Network

B.1 Example of section 4.5.1.2

The three bus power system shown in Figure 4-5 was analysed in the example included in section 4.5.1.2, presenting the application of different transmission pricing methods. Particularly the long term behaviour of the system is shown in Figure B-1. For each demand period Figure B-1 presents the optimal despatch of the generating units to supply the demand considering transmission constraints and the resulting power flows by line. As a result LRMC at each node are discovered.

The main data of the system are as follows:

- Generators capacities: G1= 400 MW, G2A= 210 MW, G2B= 60 MW, G3= 100 MW
- Production costs: G1= 10 £/MWh, G2A= 22 £/MWh, G2B= 40 £/MWh, G3= 15 £/MWh
- Three demand periods: 100%, 75% and 50% of peak demand with duration of 720 hours, 2800 hours and 5240 hours respectively
- Line reactances and length: 0.2 p.u. and 300 km respectively, every line
- Transmission investment factor: 53 £/MW-km-year

Optimal transmission capacities of the EAN are: L12= 208 MW, L23= 92 MW and L13= 117 MW.

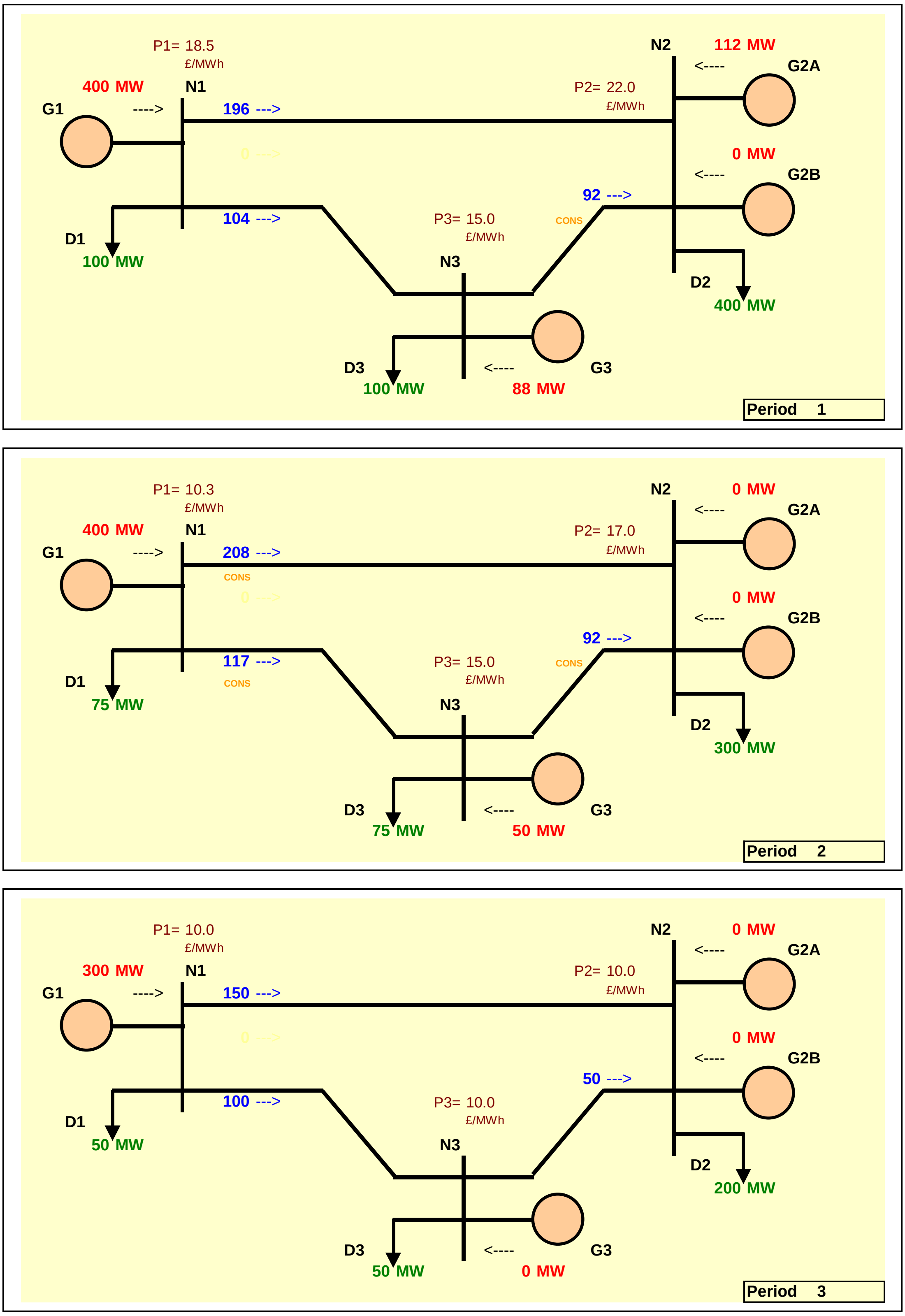

Figure B-1: Long term system behaviour by period (prices are LRMC)

(note: "cons" indicates an active transmission constraint)

B.2 LRMC and SRMC pricing on a radial network

The following example presents the calculation of the Economically Adapted Network (EAN), LRMC and SRMC performed on the three bus radial system shown in Figure B-2, considering three demand periods. Data are the same of the previous example except production costs (G1=12£/MWh, G2A= 17£/MWh, G2B= 40£/MWh, G3= 25 £/MWh).

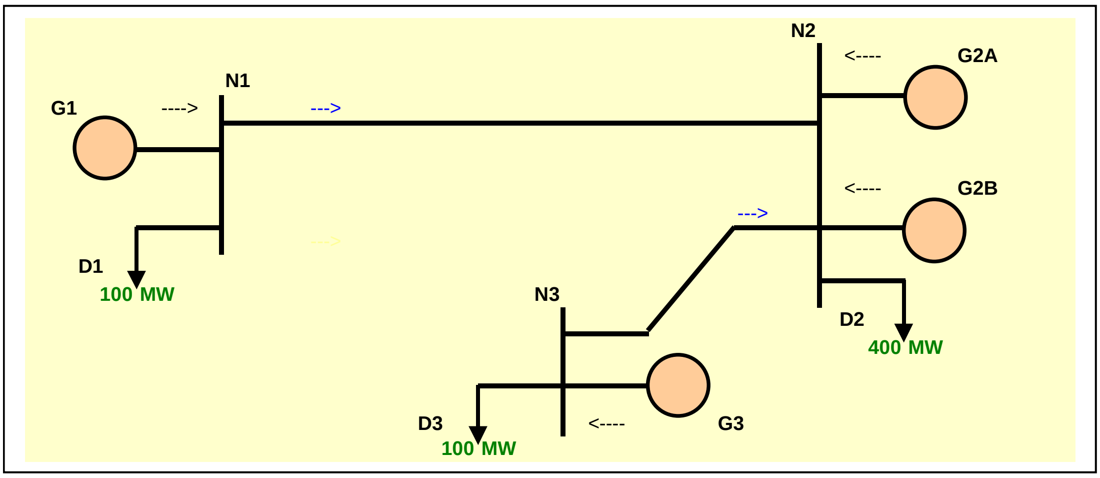

Figure B-2: Three bus radial system

The optimal transmission capacities of the EAN that result are: L12= 300 MW and L23= 75 MW. Total operation cost is 41,514 Thousand £ and the optimal transmission annuitised investment cost is 5,962 Thousand £.

B2.1 LRMC

Long-Run Marginal Costs (LRMC) are shown in Table B-1.

Table B-1: LRMC (£/MWh)

	Node 1	Node 2	Node 3
Period 1	22.4	25.0	25.0
Period 2	12.0	17.0	22.7
Period 3	12.0	12.0	12.0

In Figure B-3, despatch by generators, power flows by line and LRMC at every node of the system are deployed, for everyone of the periods.

As it was expected, the application of LRMC for transmission pricing means that nodal LRMC surplus is equal to the total transmission investment cost. Table B-2 presents the LRMC transactions in the system. Table B-3 presents the transmission investment costs.

Table B-2: LRMC Transactions (Thousand £)

Generation	Period 1	Period 2	Period 3	Total
G1	6440	12600	18864	37904
G2A	1800	3570	0	5370
G2B	0	0	0	0
G3	1800	0	0	1800
Total Generation	10040	16170	18864	45074
Demand	Period 1	Period 2	Period 3	Total
D1	-1610	-2520	-3144	-7274
D2	-7200	-14280	-12576	-34056
D3	-1800	-4762	-3144	-9706
Total Demand	-10610	-21562	-18864	-51036
Total Gen. + Demand	-570	-5393	0	-5962
Transmission	Period 1	Period 2	Period 3	Total
L12	570	4200	0	4770
L23	0	1192	0	1192
L31	0	0	0	0
Total Transmission	570	5393	0	5962

Table B-3: Transmission Investment Costs (Thousand £)

Optimal Transmission Investment				
Line	Capacity MW	Length km	Cost £/MW-km	Annuity of Investment Th. £
L12	300	300	53	4770
L23	75	300	53	1192
L31	0	300	53	0
Total Transmission Investments				5962

Moreover the equality between the total LRMC surplus and the total transmission investment cost, individual line investments are perfectly matched to its corresponding LRMC surplus. Therefore the discrepancy between LRMC surplus and transmission investment cost on a line per line basis disappears on radial networks.

B2.2 Transmission pricing based on SRMC

Short-Run Marginal Costs (SRMC) are shown in Table B-4.

Table B-4: SRMC (£/MWh)

	Node 1	Node 2	Node 3
Period 1	12.0	25.0	25.0
Period 2	12.0	17.0	25.0
Period 3	12.0	12.0	12.0

It can be noted that SRMC figures are similar to LRMC, nevertheless they differ at node 1, period 1, and node 3, period 2, because in the short term transmission capacity is fixed and then an additional MWh required at a node must be supplied only with local generation if a transmission constraint is binding.

Table B-5 presents the SRMC transactions in the system. It can be observed that the SRMC revenue has no relationship with transmission investment costs.

Table B-5: SRMC Transactions (Thousand £)

Generation	Period 1	Period 2	Period 3	Total
G1	3456	12600	18864	34920
G2A	1800	3570	0	5370
G2B	0	0	0	0
G3	1800	0	0	1800
Total Generation	7056	16170	18864	42090
Demand	Period 1	Period 2	Period 3	Total
D1	-864	-2520	-3144	-6528
D2	-7200	-14280	-12576	-34056
D3	-1800	-5250	-3144	-10194
Total Demand	-9864	-22050	-18864	-50778
Total Gen. + Demand	-2808	-5880	0	-8688
Transmission	Period 1	Period 2	Period 3	Total
L12	2808	4200	0	7008
L23	0	1680	0	1680
L31	0	0	0	0
Total Transmission	2808	5880	0	8688

Therefore, the SRMC surplus cannot be considered for transmission pricing and it is better to consider the SRMC surplus as a sub-product of the energy market which can be used to create a set of financial rights for hedging purposes, for instance.

In Figure B-4, despatch by generators, power flows by line and SRMC at every node of the system are deployed, for everyone of the periods.

B2.3 Sensitivity Analysis

B2.3.1 Optimal transmission capacities

A sensitivity analysis on transmission capacities was performed in order to demonstrate the robustness of the EAN calculations. Transmission capacities were slightly increased and decreased with respect to the optimal capacity figures. The analysis probed that the calculated optimal transmission capacities really achieved the minimum cost solution for the system. The results are shown in Table B-6.

Table B-6: Operation, Investment and Total Costs Sensitivity Analysis (Thousand £)

Transmission Capacity L12 L23	Optimal 300 MW 75 MW	290 MW 75 MW	310 MW 75 MW	300 MW 70 MW	300 MW 80 MW
Costs: Operation Investment	41,514 5,962	41,748 5,803	41,374 6,121	41,626 5,883	41,514 6,042
Total Cost	47,476	47,551	47,495	47,509	47,557

B2.3.2 SRMC calculations

Another sensitivity analysis was performed in order to demonstrate the robustness of the SRMC calculations. The transmission capacity of line L12 was increased slightly in 0.1 MW (to 300.1 MW) in order to check its impact on nodal SRMC calculations. Results are shown in Table B-7.

Table B-7: SRMC (£/MWh)

	Node 1	Node 2	Node 3
Period 1	25.0	25.0	25.0
Period 2	12.0	17.0	25.0
Period 3	12.0	12.0	12.0

Table B-8 presents the SRMC transactions in the system. It can be noted that SRMC revenues are lower than figures presented in Table B-5 due to the unconstrained situation at Line L12 that occurs in Period 1. In summary, SRMC calculations are highly volatile and therefore SRMC transmission revenues are as low or high depending on branches that are binding at any particular operational condition.

Table B-8: SRMC Transactions (Thousand £)

Generation	Period 1	Period 2	Period 3	Total
G1	7200	12603	18864	38667
G2A	1800	3565	0	5365
G2B	0	0	0	0
G3	1800	0	0	1800
Total Generation	10800	16169	18864	45833
Demand	Period 1	Period 2	Period 3	Total
D1	-1800	-2520	-3144	-7464
D2	-7200	-14280	-12576	-34056
D3	-1800	-5250	-3144	-10194
Total Demand	-10800	-22050	-18864	-51714
Total Gen. + Demand	0	-5881	0	-5881
Transmission	Period 1	Period 2	Period 3	Total
L12	0	4201	0	4201
L23	0	1680	0	1680
L31	0	0	0	0
Total Transmission	0	5881	0	5881

In Figure B-5, despatch by generators, power flows by line and SRMC at every node of the system are deployed, for everyone of the periods.

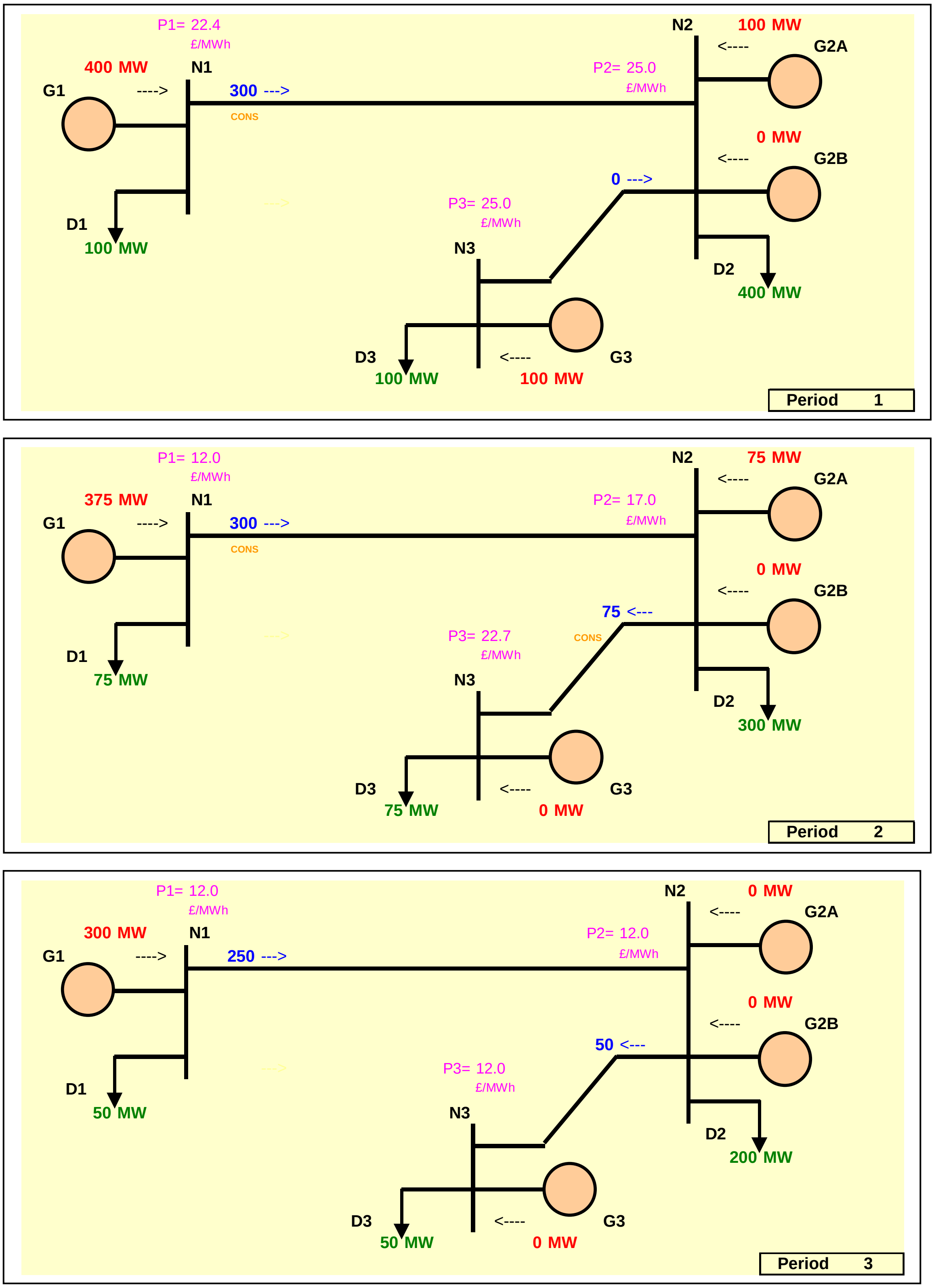

Figure B-3: Long term system behaviour per period (prices are LRMC)

(note: "cons" indicates an active transmission constraint)

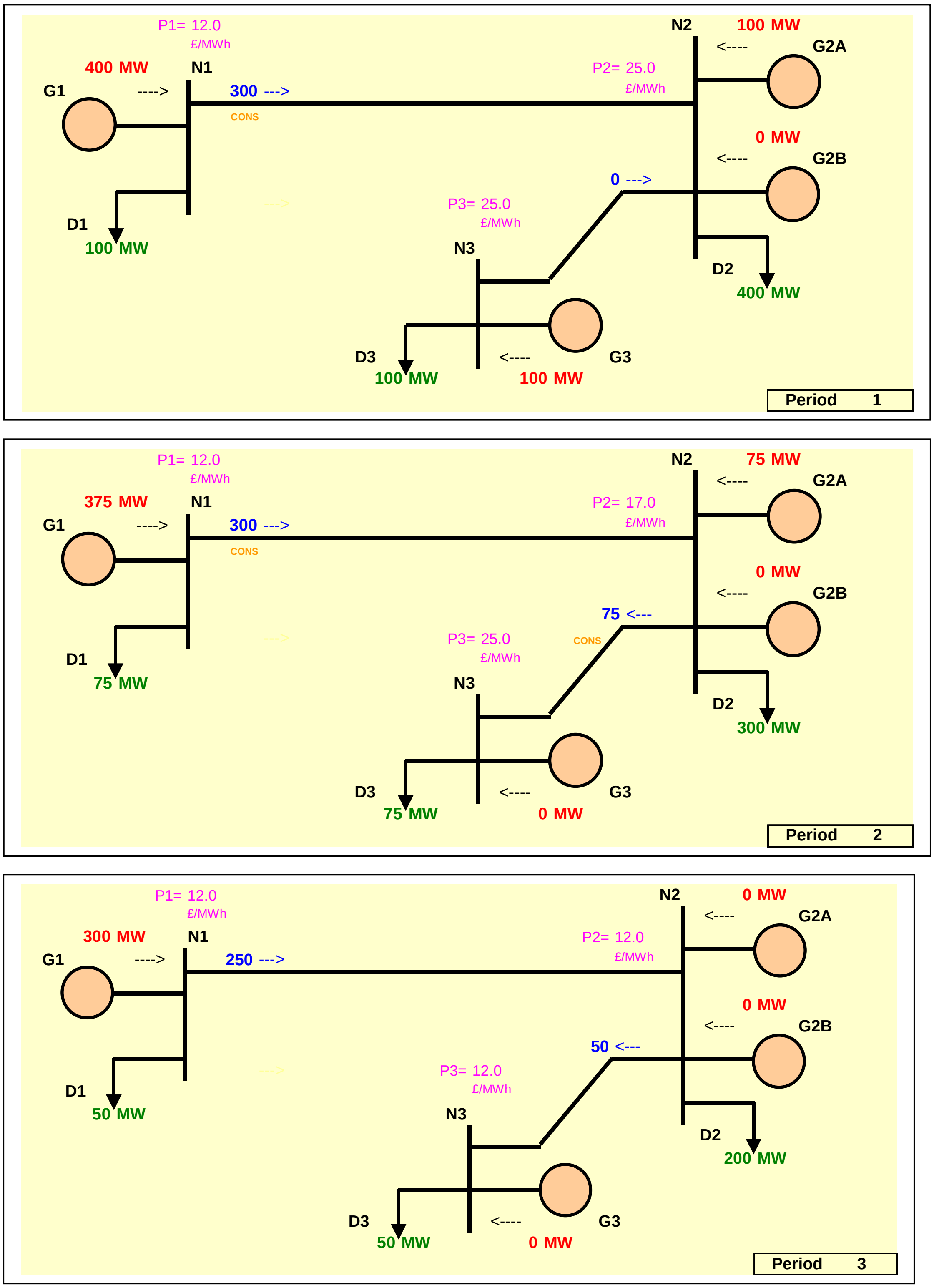

Figure B-4: Short term system behaviour per period (prices are SRMC)

(note: "cons" indicates an active transmission constraint)

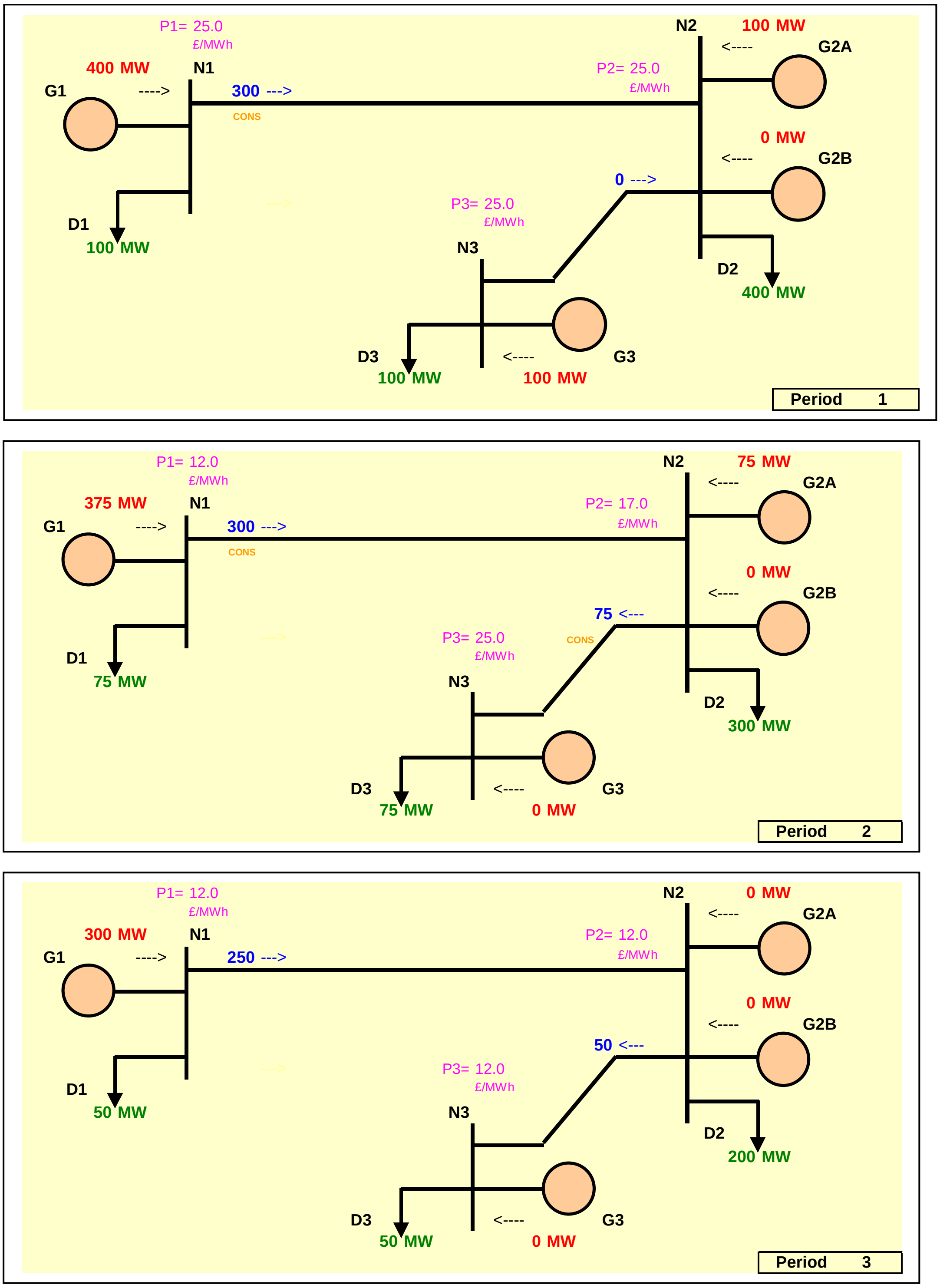

Figure B-5: Short term system behaviour per period (prices are SRMC)

Sensitivity analysis: adding 0.1 MW more capacity at Line L12

(note: "cons" indicates an active transmission constraint)

Appendix C

Simulations on the IEEE 24-Bus Network

C1. Description of the IEEE 24-Bus Network

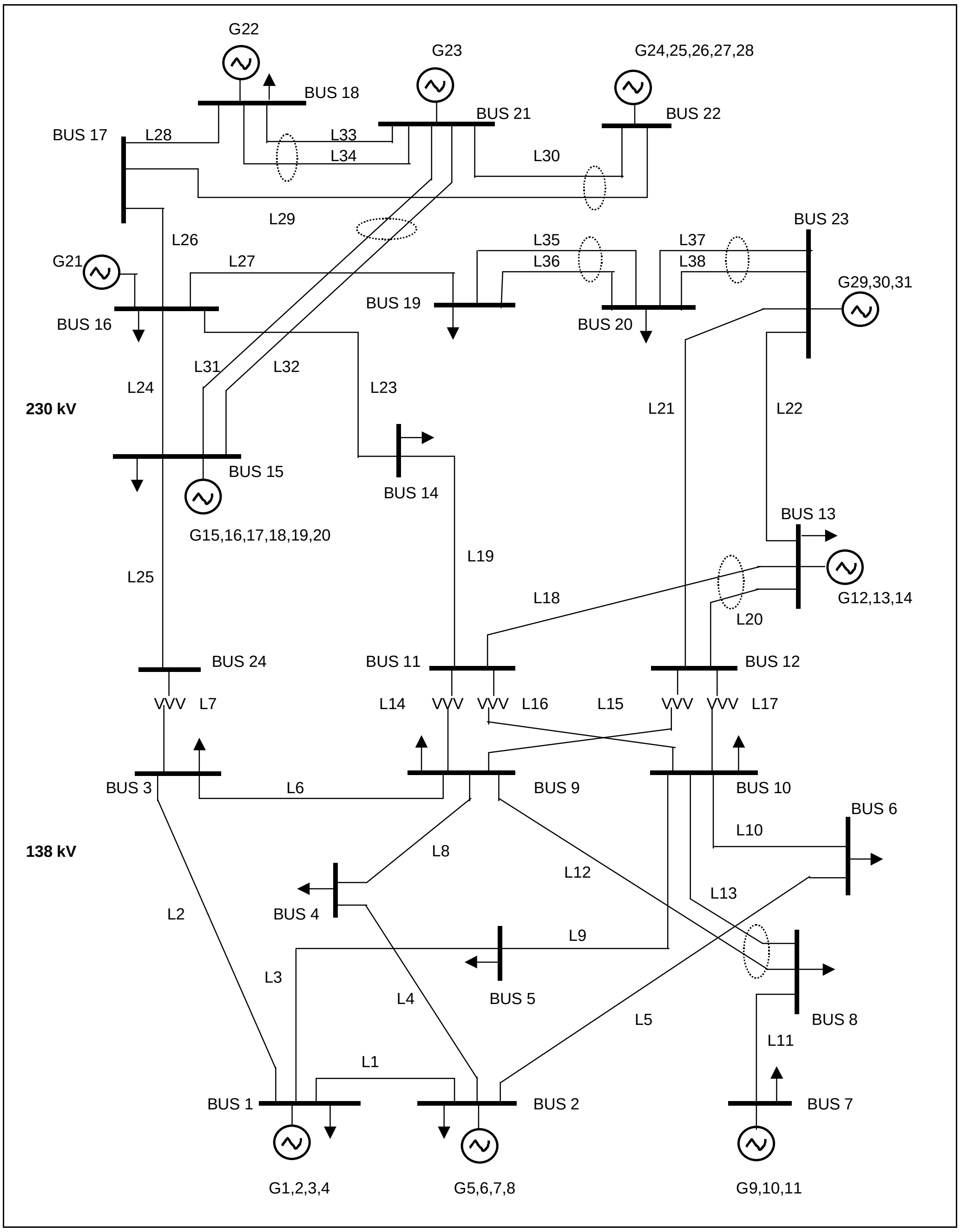

Figure C-1 Topology of the IEEE 24-Bus Reliability Test System

Table C-1 Transmission network data for modified IEEE 24-bus Reliability Test System

Line	From bus	To bus	Reactance (p.u.) on 100 MVA base	Capacity (MVA)	Length (km)	Incremental investment cost (£/MW-km-yr)
1	1	2	0.0139	175	3	30
2	1	3	0.2112	175	55	30
3	1	5	0.0845	175	22	30
4	2	4	0.1267	175	33	30
5	2	6	0.1920	175	50	30
6	3	9	0.1190	175	31	30
7	3	24	0.0839	400	50	30
8	4	9	0.1037	175	27	30
9	5	10	0.0883	175	23	30
10	6	10	0.0605	175	16	30
11	7	8	0.0614	175	16	30
12	8	9	0.1651	175	43	30
13	8	10	0.1651	175	43	30
14	9	11	0.0839	400	50	30
15	9	12	0.0839	400	50	30
16	10	11	0.0839	400	50	30
17	10	12	0.0839	400	50	30
18	11	13	0.0476	500	33	30
19	11	14	0.0418	500	29	30
20	12	13	0.0476	500	33	30
21	12	23	0.0966	500	67	30
22	13	23	0.0865	500	60	30
23	14	16	0.0389	500	27	30
24	15	16	0.0173	500	12	30
25	15	24	0.0519	500	36	30
26	16	17	0.0259	500	18	30
27	16	19	0.0231	500	16	30
28	17	18	0.0144	500	10	30
29	17	22	0.1053	500	73	30
30	21	22	0.0678	500	47	30
31	15	21	0.0490	500	34	30
32	15	21	0.0490	500	34	30
33	18	21	0.0259	500	18	30
34	18	21	0.0259	500	18	30
35	19	20	0.0396	500	27	30
36	19	20	0.0396	500	27	30
37	20	23	0.0216	500	15	30
38	20	23	0.0216	500	15	30

Table C-2 Generation data for modified IEEE 24-bus Reliability Test System

Generator	Connection bus	Maximum output (MW)	Minimum output (MW)	Operating cost (£/MWh)
1	1	20	0	50.00
2	1	20	0	50.00
3	1	76	0	15.30
4	1	76	0	15.30
5	2	20	0	50.00
6	2	20	0	50.00
7	2	76	0	15.30
8	2	76	0	15.30
9	7	100	0	24.03
10	7	100	0	24.03
11	7	100	0	24.03
12	13	197	0	23.33
13	13	197	0	23.33
14	13	197	0	23.33
15	15	12	0	29.10
16	15	12	0	29.10
17	15	12	0	29.10
18	15	12	0	29.10
19	15	12	0	29.10
20	15	155	0	12.44
21	16	155	0	12.44
22	18	400	0	6.30
23	21	400	0	6.30
24	22	50	0	0.00
25	22	50	0	0.00
26	22	50	0	0.00
27	22	50	0	0.00
28	22	50	0	0.00
29	23	155	0	12.44
30	23	155	0	12.44
31	23	350	0	12.10

C2. Demand data for studies on the IEEE 24-Bus Network

Table C-3 Demand peak for modified IEEE 24-bus Reliability Test System

Bus	Peak demand (MW)
1	108
2	97
3	180
4	74
5	71
6	136
7	125
8	171
9	175
10	195
11	0
12	0
13	265
14	194
15	317
16	100
17	0
18	333
19	181
20	128
21	0
22	0
23	0
24	0
Total	2850

Table C-4 Daily peak load in Percent of Weekly Peak

Day	Day number	Peak load
Monday	1	93
Tuesday	2	100
Wednesday	3	98
Thursday	4	96
Friday	5	94
Saturday	6	77
Sunday	7	75

Table C-5 Weekly peak load in Percent of Annual Peak

Week	Peak load	Week	Peak load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

Table C-6 Hourly peak load in Percent of Daily Peak

Hour	Winter weeks week 1-8 & 44-52		Summer weeks week 18-30		Spring/Fall weeks week 9-17 & 31-43	
	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
1	67	78	64	74	63	75
2	63	72	60	70	62	73
3	60	68	58	66	60	69
4	59	66	56	65	58	66
5	59	64	56	64	59	65
6	60	65	58	62	65	65
7	74	66	64	62	72	68
8	86	70	76	66	85	74
9	95	80	87	81	95	83
10	96	88	95	86	99	89
11	96	90	99	91	100	92
12	95	91	100	93	99	94
13	95	90	99	93	93	91
14	95	88	100	92	92	90
15	93	87	100	91	90	90
16	94	87	97	91	88	86
17	99	91	96	92	90	85
18	100	100	96	94	92	88
19	100	99	93	95	96	92
20	96	97	92	95	98	100
21	91	94	92	100	96	97
22	83	92	93	93	90	95
23	73	87	87	88	80	90
24	63	81	72	80	70	85

Table C-7 Load duration curve for modified IEEE 24-bus Reliability Test System (sampling data for 50 demand periods)

Demand period	Load in MW	Duration in Hours
1	2850	3
2	2812	2
3	2775	3
4	2737	15
5	2699	12
6	2662	32
7	2624	21
8	2586	47
9	2549	73
10	2511	79
11	2473	103
12	2435	126
13	2398	168
14	2360	185
15	2322	185
16	2285	188
17	2247	220
18	2209	167
19	2172	197
20	2134	185
21	2096	164
22	2059	208
23	2021	208
24	1983	243
25	1946	259

Demand period	Load in MW	Duration in Hours
26	1908	259
27	1870	283
28	1832	286
29	1795	307
30	1757	269
31	1719	242
32	1682	217
33	1644	215
34	1606	228
35	1569	242
36	1531	256
37	1493	289
38	1456	330
39	1418	338
40	1380	304
41	1342	265
42	1305	246
43	1267	236
44	1229	235
45	1192	211
46	1154	145
47	1116	90
48	1079	69
49	1041	62
50	1003	19

Table C-8 Load duration curve for modified IEEE 24-bus Reliability Test System (sampling data for 5 demand periods)

Demand period	Load in MW	Duration in Hours
1	2850	287
2	2473	1724
3	2096	2486
4	1719	2661
5	1342	1578

C3. Results of simulations on the IEEE 24-Bus Network (5 demand periods)

Table C-9 Optimal capacity and power flows per period

Branch	Optimal Capacity (MW)	Intact Flows per period (MW)						Contingency Flows per period (MW)					
		1	2	3	4	5	Max.	1	2	3	4	5	Max.
1	88	10.5	15.5	22.0	25.4	21.8	25.4	79.2	65.3	88.0	88.0	69.7	88.0
2	113	-13.9	-18.9	-71.5	-77.1	-64.3	77.1	51.8	-57.1	-113.5	-113.5	-95.4	113.5
3	86	47.4	61.7	4.0	-13.5	-8.4	61.7	71.6	86.5	52.2	-57.3	-41.9	86.5
4	74	25.9	35.2	-14.3	-27.2	-20.6	35.2	74.0	64.2	54.4	-56.4	-44.9	74.0
5	136	39.6	48.1	7.3	-5.9	-3.3	48.1	136.0	118.0	100.0	82.0	64.1	136.0
6	144	11.7	47.7	54.3	48.2	46.3	54.3	-128.2	128.8	143.6	125.6	112.6	143.6
7	389	-205.6	-222.9	-258.2	-233.8	-195.4	258.2	-310.6	-342.1	-389.5	-347.7	-292.8	389.5
8	101	-48.1	-29.0	-68.7	-71.9	-55.5	71.9	-75.8	-64.2	-95.5	-101.0	-79.8	101.0
9	100	-23.6	0.1	-48.2	-56.3	-41.8	56.3	-71.6	-61.6	-94.4	-100.1	-75.4	100.1
10	136	-96.4	-69.9	-92.8	-88.0	-67.3	96.4	-136.0	-118.0	-119.9	-112.6	-87.9	136.0
11	142	142.3	-69.3	-91.9	-75.4	-58.9	142.3	142.3	-69.3	-91.9	-75.4	-58.9	142.3
12	218	-24.9	-119.6	-123.2	-102.7	-80.8	123.2	-52.9	-217.7	-217.7	-178.6	-139.4	217.7
13	218	-3.9	-98.1	-94.5	-75.8	-58.6	98.1	-28.7	-217.7	-217.7	-178.6	-139.4	217.7
14	232	-108.4	-122.2	-133.8	-117.7	-93.8	133.8	-186.3	-206.6	-231.6	-206.2	-167.7	231.6
15	211	-127.8	-130.4	-132.5	-114.3	-78.7	132.5	-195.6	-199.7	-211.0	-185.4	-138.1	211.0
16	302	-149.8	-164.5	-190.2	-170.6	-137.4	190.2	-249.7	-266.6	-301.8	-269.4	-209.7	301.8
17	300	-169.1	-172.7	-188.8	-167.2	-122.3	188.8	-256.5	-268.6	-299.7	-266.7	-202.4	299.7
18	283	-113.5	-70.1	-42.9	-37.7	-7.8	113.5	-282.9	-262.7	-254.9	-221.6	-165.2	282.9
19	421	-144.8	-216.6	-281.1	-250.6	-223.4	281.1	-255.8	-337.0	-420.6	-376.9	-358.4	420.6
20	206	-79.4	-55.7	-45.3	-43.8	-34.4	79.4	-206.1	-199.9	-206.1	-182.3	-131.5	206.1
21	426	-217.5	-247.5	-275.9	-237.7	-166.5	275.9	-322.8	-377.4	-425.7	-365.3	-260.3	425.7
22	449	-199.1	-245.7	-283.2	-241.4	-167.0	283.2	-332.0	-396.7	-449.4	-385.6	-290.5	449.4
23	563	-338.8	-385.0	-423.8	-367.6	-314.7	423.8	-449.8	-505.3	-563.2	-493.9	-449.8	563.2
24	526	57.3	95.8	119.6	164.1	149.8	164.1	333.0	400.1	449.2	523.5	526.2	526.2
25	389	205.6	222.9	258.2	233.8	195.4	258.2	310.6	342.1	389.5	347.7	292.8	389.5
26	518	-292.1	-322.3	-349.1	-380.7	-398.6	398.6	-382.7	-415.9	-446.4	-511.6	-518.2	518.2
27	419	65.6	101.3	126.4	116.9	186.6	186.6	299.4	367.1	418.9	370.6	403.9	418.9
28	379	-172.0	-200.9	-226.9	-257.1	-275.4	275.4	-257.2	-287.0	-313.6	-370.1	-378.6	378.6
29	250	-120.1	-121.4	-122.2	-123.6	-123.2	123.6	-250.0	-250.0	-250.0	-250.0	-250.0	250.0
30	250	-129.9	-128.6	-127.8	-126.4	-126.8	129.9	-250.0	-250.0	-250.0	-250.0	-250.0	250.0
31	447	-212.5	-219.4	-228.0	-234.2	-247.3	247.3	-358.5	-380.5	-402.5	-424.6	-446.6	446.6
32	447	-212.5	-219.4	-228.0	-234.2	-247.3	247.3	-358.5	-380.5	-402.5	-424.6	-446.6	446.6
33	156	-52.5	-45.0	-35.9	-29.0	-16.1	52.5	-95.1	94.2	114.8	135.4	156.0	156.0
34	156	-52.5	-45.0	-35.9	-29.0	-16.1	52.5	-95.1	94.2	114.8	135.4	156.0	156.0
35	159	-57.7	-27.9	-3.4	3.8	50.7	57.7	-105.6	105.0	142.9	130.7	159.3	159.3
36	159	-57.7	-27.9	-3.4	3.8	50.7	57.7	-105.6	105.0	142.9	130.7	159.3	159.3
37	230	-121.7	-83.4	-50.5	-34.8	20.5	121.7	-229.9	-157.5	-117.2	-93.2	129.2	229.9
38	230	-121.7	-83.4	-50.5	-34.8	20.5	121.7	-229.9	-157.5	-117.2	-93.2	129.2	229.9

Table C-10 Binding flows and security factor per period

	Binding Flows per period (MW)					Security factor (o/1)				
Branch	1	2	3	4	5	1	2	3	4	5
1	0.0	0.0	88.0	88.0	0.0	8.3	5.7	4.0	3.5	4.0
2	0.0	0.0	113.5	113.5	0.0	-8.1	-6.0	-1.6	-1.5	-1.8
3	0.0	86.5	0.0	0.0	0.0	1.8	1.4	21.4	-6.4	-10.3
4	74.0	0.0	0.0	0.0	0.0	2.9	2.1	-5.2	-2.7	-3.6
5	136.0	0.0	0.0	0.0	0.0	3.4	2.8	18.7	-22.9	-41.4
6	0.0	0.0	143.6	0.0	0.0	12.3	3.0	2.6	3.0	3.1
7	0.0	0.0	389.5	0.0	0.0	-1.9	-1.7	-1.5	-1.7	-2.0
8	0.0	0.0	95.5	101.0	0.0	-2.1	-3.5	-1.5	-1.4	-1.8
9	0.0	0.0	94.4	100.1	0.0	-4.2	1114.8	-2.1	-1.8	-2.4
10	136.0	0.0	0.0	0.0	0.0	-1.4	-1.9	-1.5	-1.5	-2.0
11	142.3	0.0	0.0	0.0	0.0	1.0	-2.1	-1.5	-1.9	-2.4
12	0.0	217.7	217.7	0.0	0.0	-8.8	-1.8	-1.8	-2.1	-2.7
13	0.0	217.7	217.7	0.0	0.0	-56.4	-2.2	-2.3	-2.9	-3.7
14	0.0	0.0	231.6	0.0	0.0	-2.1	-1.9	-1.7	-2.0	-2.5
15	195.6	199.7	211.0	0.0	0.0	-1.7	-1.6	-1.6	-1.8	-2.7
16	0.0	0.0	301.8	0.0	0.0	-2.0	-1.8	-1.6	-1.8	-2.2
17	0.0	0.0	299.7	0.0	0.0	-1.8	-1.7	-1.6	-1.8	-2.5
18	282.9	262.7	254.9	0.0	0.0	-2.5	-4.0	-6.6	-7.5	-36.3
19	0.0	0.0	420.6	0.0	0.0	-2.9	-1.9	-1.5	-1.7	-1.9
20	206.1	199.9	206.1	0.0	0.0	-2.6	-3.7	-4.5	-4.7	-6.0
21	0.0	0.0	425.7	0.0	0.0	-2.0	-1.7	-1.5	-1.8	-2.6
22	0.0	0.0	449.4	0.0	0.0	-2.3	-1.8	-1.6	-1.9	-2.7
23	0.0	0.0	563.2	0.0	0.0	-1.7	-1.5	-1.3	-1.5	-1.8
24	0.0	0.0	0.0	523.5	526.2	9.2	5.5	4.4	3.2	3.5
25	0.0	0.0	389.5	0.0	0.0	1.9	1.7	1.5	1.7	2.0
26	0.0	0.0	0.0	511.6	518.2	-1.8	-1.6	-1.5	-1.4	-1.3
27	0.0	0.0	418.9	0.0	403.9	6.4	4.1	3.3	3.6	2.2
28	0.0	0.0	0.0	370.1	378.6	-2.2	-1.9	-1.7	-1.5	-1.4
29	250.0	250.0	250.0	250.0	250.0	-2.1	-2.1	-2.0	-2.0	-2.0
30	250.0	250.0	250.0	250.0	250.0	-1.9	-1.9	-2.0	-2.0	-2.0
31	0.0	0.0	402.5	424.6	446.6	-2.1	-2.0	-2.0	-1.9	-1.8
32	0.0	0.0	402.5	424.6	446.6	-2.1	-2.0	-2.0	-1.9	-1.8
33	0.0	0.0	0.0	0.0	156.0	-3.0	-3.5	-4.3	-5.4	-9.7
34	0.0	0.0	0.0	0.0	156.0	-3.0	-3.5	-4.3	-5.4	-9.7
35	0.0	0.0	0.0	0.0	159.3	-2.8	-5.7	-47.1	41.6	3.1
36	0.0	0.0	0.0	0.0	159.3	-2.8	-5.7	-47.1	41.6	3.1
37	229.9	0.0	0.0	0.0	0.0	-1.9	-2.8	-4.6	-6.6	11.2
38	229.9	0.0	0.0	0.0	0.0	-1.9	-2.8	-4.6	-6.6	11.2

Table C-11 Circuit prices and circuit revenue

Branch	Circuit Prices (£/MWh) period 1	2	3	4	5	Circuit Revenue (Thousand £) period 1	2	3	4	5	Total	Investment (Thous. £)
1	0.000	0.000	0.070	0.061	0.000	0.0	0.0	3.8	4.1	0.0	7.9	7.9
2	0.000	0.000	-0.509	-0.472	0.000	0.0	0.0	90.4	96.8	0.0	187.3	187.3
3	0.000	0.537	0.000	0.000	0.000	0.0	57.1	0.0	0.0	0.0	57.1	57.1
4	9.838	0.000	0.000	0.000	0.000	73.3	0.0	0.0	0.0	0.0	73.3	73.3
5	17.948	0.000	0.000	0.000	0.000	204.0	0.0	0.0	0.0	0.0	204.0	204.0
6	0.000	0.000	0.989	0.000	0.000	0.0	0.0	133.5	0.0	0.0	133.5	133.5
7	0.000	0.000	-0.910	0.000	0.000	0.0	0.0	584.2	0.0	0.0	584.2	584.2
8	0.000	0.000	-0.231	-0.221	0.000	0.0	0.0	39.5	42.3	0.0	81.8	81.8
9	0.000	0.000	-0.278	-0.238	0.000	0.0	0.0	33.4	35.7	0.0	69.1	69.1
10	-2.360	0.000	0.000	0.000	0.000	65.3	0.0	0.0	0.0	0.0	65.3	65.3
11	1.672	0.000	0.000	0.000	0.000	68.3	0.0	0.0	0.0	0.0	68.3	68.3
12	0.000	-0.558	-0.542	0.000	0.000	0.0	115.0	165.8	0.0	0.0	280.9	280.9
13	0.000	-0.680	-0.706	0.000	0.000	0.0	115.0	165.8	0.0	0.0	280.9	280.9
14	0.000	0.000	-1.044	0.000	0.000	0.0	0.0	347.4	0.0	0.0	347.4	347.4
15	-0.551	-0.539	-0.531	0.000	0.000	20.2	121.3	174.9	0.0	0.0	316.5	316.5
16	0.000	0.000	-0.958	0.000	0.000	0.0	0.0	452.6	0.0	0.0	452.6	452.6
17	0.000	0.000	-0.958	0.000	0.000	0.0	0.0	449.6	0.0	0.0	449.6	449.6
18	-0.549	-0.888	-1.451	0.000	0.000	17.9	107.4	154.8	0.0	0.0	280.1	280.1
19	0.000	0.000	-0.524	0.000	0.000	0.0	0.0	365.9	0.0	0.0	365.9	365.9
20	-0.572	-0.815	-1.001	0.000	0.000	13.0	78.2	112.8	0.0	0.0	204.1	204.1
21	0.000	0.000	-1.247	0.000	0.000	0.0	0.0	855.6	0.0	0.0	855.6	855.6
22	0.000	0.000	-1.149	0.000	0.000	0.0	0.0	808.9	0.0	0.0	808.9	808.9
23	0.000	0.000	-0.433	0.000	0.000	0.0	0.0	456.2	0.0	0.0	456.2	456.2
24	0.000	0.000	0.000	0.272	0.298	0.0	0.0	0.0	118.9	70.5	189.4	189.4
25	0.000	0.000	0.655	0.000	0.000	0.0	0.0	420.6	0.0	0.0	420.6	420.6
26	0.000	0.000	0.000	-0.173	-0.166	0.0	0.0	0.0	175.6	104.2	279.8	279.8
27	0.000	0.000	0.392	0.000	0.265	0.0	0.0	123.0	0.0	78.1	201.1	201.1
28	0.000	0.000	0.000	-0.104	-0.097	0.0	0.0	0.0	71.3	42.3	113.6	113.6
29	-0.522	-0.516	-0.513	-0.507	-0.509	18.0	108.0	155.8	166.8	98.9	547.5	547.5
30	-0.311	-0.314	-0.316	-0.319	-0.318	11.6	69.6	100.3	107.4	63.7	352.5	352.5
31	0.000	0.000	-0.297	-0.289	-0.274	0.0	0.0	168.4	180.2	106.9	455.5	455.5
32	0.000	0.000	-0.297	-0.289	-0.274	0.0	0.0	168.4	180.2	106.9	455.5	455.5
33	0.000	0.000	0.000	0.000	-3.311	0.0	0.0	0.0	0.0	84.2	84.2	84.2
34	0.000	0.000	0.000	0.000	-3.311	0.0	0.0	0.0	0.0	84.2	84.2	84.2
35	0.000	0.000	0.000	0.000	1.614	0.0	0.0	0.0	0.0	129.0	129.0	129.0
36	0.000	0.000	0.000	0.000	1.614	0.0	0.0	0.0	0.0	129.0	129.0	129.0
37	-2.962	0.000	0.000	0.000	0.000	103.5	0.0	0.0	0.0	0.0	103.5	103.5
38	-2.962	0.000	0.000	0.000	0.000	103.5	0.0	0.0	0.0	0.0	103.5	103.5
					Total	698.4	771.6	6531.9	1179.4	1097.9	10279.2	10279.2

Table C-12 Nodal transmission prices

Node	Nodal Prices referred to node 1 (£/MWh)					Shifted Nodal Prices (£/MWh)				
	1	2	3	4	5	1	2	3	4	5
1	0.000	0.000	0.000	0.000	0.000	4.834	-0.014	-1.799	-0.360	-0.256
2	0.728	-0.023	-0.071	-0.046	-0.012	5.562	-0.037	-1.870	-0.407	-0.267
3	-4.398	-0.110	0.831	0.335	0.364	0.436	-0.124	-0.967	-0.025	0.108
4	-7.199	-0.159	-0.131	-0.024	-0.045	-2.365	-0.173	-1.929	-0.384	-0.300
5	-2.665	-0.354	-0.123	-0.033	-0.075	2.169	-0.369	-1.921	-0.393	-0.331
6	-10.064	-0.130	0.004	0.119	-0.120	-5.230	-0.144	-1.794	-0.241	-0.376
7	-3.869	-0.836	-0.584	0.193	-0.113	0.965	-0.850	-2.382	-0.167	-0.369
8	-5.542	-0.836	-0.584	0.193	-0.113	-0.708	-0.850	-2.382	-0.167	-0.369
9	-5.634	-0.270	0.052	0.215	-0.072	-0.800	-0.284	-1.747	-0.145	-0.328
10	-5.449	-0.164	0.028	0.171	-0.154	-0.615	-0.178	-1.771	-0.189	-0.410
11	-5.443	-0.184	0.929	0.184	-0.098	-0.609	-0.198	-0.869	-0.176	-0.354
12	-4.928	-0.015	0.906	0.187	-0.354	-0.094	-0.029	-0.893	-0.174	-0.610
13	-4.472	0.629	1.942	0.184	-0.367	0.362	0.615	0.144	-0.176	-0.623
14	-5.714	-0.085	1.726	0.176	0.153	-0.880	-0.099	-0.073	-0.184	-0.103
15	-5.815	0.001	2.365	0.384	1.095	-0.981	-0.013	0.567	0.024	0.839
16	-5.967	0.007	2.413	0.169	0.386	-1.133	-0.007	0.615	-0.192	0.131
17	-5.924	-0.004	2.491	0.418	-0.201	-1.090	-0.019	0.692	0.057	-0.457
18	-5.888	0.004	2.542	0.564	-0.697	-1.054	-0.010	0.744	0.204	-0.952
19	-6.358	0.081	2.167	0.173	0.384	-1.524	0.067	0.369	-0.188	0.129
20	-6.694	0.145	2.292	0.176	-1.004	-1.860	0.130	0.494	-0.184	-1.259
21	-5.856	0.012	2.589	0.602	2.081	-1.022	-0.002	0.790	0.242	1.825
22	-5.489	0.399	2.943	0.923	1.580	-0.655	0.385	1.145	0.562	1.324
23	-3.914	0.179	2.360	0.178	-0.881	0.920	0.165	0.562	-0.183	-1.136
24	-5.274	-0.041	1.722	0.366	0.815	-0.440	-0.056	-0.076	0.005	0.560

	1	2	3	4	5
Shift	-4.834	0.014	1.799	0.360	0.256

Table C-13 Generation and demand payments of transmission charges

Node	Generation payments (Thousand £)						Demand payments (Thousand £)					
	1	2	3	4	5	Total	1	2	3	4	5	Total
1	210.9	-3.7	-151.7	0.0	0.0	55.5	149.8	-2.3	-355.2	-62.5	-20.5	-290.6
2	242.6	-9.7	-196.7	0.0	0.0	36.3	154.8	-5.4	-331.6	-63.3	-19.3	-264.7
3	0.0	0.0	0.0	0.0	0.0	0.0	22.5	-33.5	-318.3	-7.2	14.4	-322.1
4	0.0	0.0	0.0	0.0	0.0	0.0	-50.2	-19.1	-261.0	-45.7	-16.5	-392.6
5	0.0	0.0	0.0	0.0	0.0	0.0	44.2	-39.2	-249.4	-44.8	-17.5	-306.6
6	0.0	0.0	0.0	0.0	0.0	0.0	-204.1	-29.4	-446.2	-52.6	-38.0	-770.4
7	74.0	-57.4	0.0	0.0	0.0	16.6	34.6	-159.0	-544.5	-33.5	-34.3	-736.7
8	0.0	0.0	0.0	0.0	0.0	0.0	-34.7	-217.5	-744.9	-45.9	-46.9	-1089.8
9	0.0	0.0	0.0	0.0	0.0	0.0	-40.2	-74.4	-558.9	-40.8	-42.6	-756.9
10	0.0	0.0	0.0	0.0	0.0	0.0	-34.4	-52.0	-631.3	-59.2	-59.4	-836.4
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	26.9	116.5	0.0	0.0	0.0	143.4	27.6	243.6	69.6	-75.0	-122.7	143.1
14	0.0	0.0	0.0	0.0	0.0	0.0	-49.0	-28.7	-25.8	-57.3	-14.8	-175.7
15	-43.7	-3.5	218.4	7.7	0.0	179.0	-89.3	-6.2	328.5	12.2	197.7	443.0
16	-50.4	-1.8	236.9	0.0	0.0	184.7	-32.5	-1.0	112.4	-30.8	9.7	57.8
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	-121.0	-6.7	739.8	217.0	-601.2	227.9	-100.7	-4.8	453.0	109.0	-235.8	220.6
19	0.0	0.0	0.0	0.0	0.0	0.0	-79.2	18.2	122.1	-54.6	17.3	23.8
20	0.0	0.0	0.0	0.0	0.0	0.0	-68.3	25.0	115.6	-37.9	-119.8	-85.5
21	-117.3	-1.2	785.9	257.4	1152.2	2077.0	0.0	0.0	0.0	0.0	0.0	0.0
22	-47.0	165.8	711.6	374.1	522.4	1726.9	0.0	0.0	0.0	0.0	0.0	0.0
23	174.2	187.5	921.8	-266.6	-524.5	492.4	0.0	0.0	0.0	0.0	0.0	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	349.2	386.0	3266.0	589.6	548.9	5139.6	-349.2	-385.7	-3265.9	-589.8	-549.0	-5139.6

Total transmission revenue	10279.2

C4. Results of case studies on the IEEE 24-Bus Network (50 demand periods)

Table C-14 Optimal capacity of the Economically Adapted Network

	Optimal Transmission Capacity (MW)			Impact on network	
Branch	Reference Network	Robust Network	Weak Network	Robust/Ref. Dif. (%)	Weak/Ref. Dif. (%)
1	93	130	60	40%	-36%
2	118	154	80	30%	-32%
3	92	100	95	9%	3%
4	74	85	75	15%	1%
5	136	136	68	0%	-50%
6	143	173	107	21%	-25%
7	373	472	294	26%	-21%
8	107	154	73	44%	-32%
9	108	167	82	55%	-24%
10	136	182	56	34%	-59%
11	100	139	109	39%	9%
12	237	229	237	-3%	0%
13	237	229	237	-3%	0%
14	223	275	170	23%	-24%
15	205	241	168	18%	-18%
16	293	355	218	21%	-26%
17	292	349	222	20%	-24%
18	269	309	224	15%	-17%
19	402	515	293	28%	-27%
20	202	237	157	17%	-22%
21	416	469	363	13%	-13%
22	440	507	379	15%	-14%
23	545	675	436	24%	-20%
24	566	616	429	9%	-24%
25	373	472	294	26%	-21%
26	553	602	418	9%	-24%
27	460	557	342	21%	-26%
28	409	444	360	8%	-12%
29	250	250	117	0%	-53%
30	250	250	67	0%	-73%
31	453	535	353	18%	-22%
32	453	535	353	18%	-22%
33	162	176	128	8%	-21%
34	162	176	128	8%	-21%
35	196	206	137	5%	-30%
36	196	206	137	5%	-30%
37	197	183	259	-7%	31%
38	197	183	259	-7%	31%

Table C-15 Optimal capacity with and without security criteria

Branch	Optimal Transmission Capacity (MW) N Criteria	N - 1 Criteria	Overcapacity (%)
1	27	93	250%
2	82	118	44%
3	66	92	40%
4	38	74	95%
5	50	136	170%
6	59	143	144%
7	256	373	46%
8	80	107	34%
9	64	108	68%
10	99	136	38%
11	132	100	-24%
12	130	237	82%
13	109	237	118%
14	133	223	68%
15	132	205	56%
16	190	293	54%
17	189	292	54%
18	74	269	264%
19	277	402	45%
20	49	202	308%
21	274	416	52%
22	281	440	56%
23	420	545	30%
24	190	566	198%
25	256	373	46%
26	418	553	32%
27	274	460	68%
28	294	409	39%
29	124	250	101%
30	129	250	94%
31	248	453	82%
32	248	453	82%
33	57	162	184%
34	57	162	184%
35	103	196	90%
36	103	196	90%
37	106	197	86%
38	106	197	86%

Table C-16 Despatch and transmission charges for the Reference Network

Despatch and Demand by Node

Node	Generation (GWh)	Demand (GWh)
1	234.0	585.9
2	353.4	526.3
3	0.0	976.6
4	0.0	401.5
5	0.0	385.2
6	0.0	737.9
7	41.2	678.2
8	0.0	927.7
9	0.0	949.4
10	0.0	1057.9
11	0.0	0.0
12	0.0	0.0
13	82.3	1437.7
14	0.0	1052.5
15	667.8	1719.8
16	641.1	542.5
17	0.0	0.0
18	3480.4	1806.7
19	0.0	982.0
20	0.0	694.4
21	3494.4	0.0
22	2184.0	0.0
23	4283.8	0.0
24	0.0	0.0
Total	15462.3	15462.3

Nodal Transmission Payments

Node	Generation (Thousand £)	Demand (Thousand £)
1	77.8	-308.6
2	-25.4	-283.6
3	0.0	-325.1
4	0.0	-369.8
5	0.0	-305.2
6	0.0	-738.0
7	-45.4	-831.7
8	0.0	-1072.4
9	0.0	-726.0
10	0.0	-804.9
11	0.0	0.0
12	0.0	0.0
13	59.5	197.1
14	0.0	-183.1
15	135.7	401.3
16	114.4	45.4
17	0.0	0.0
18	113.5	137.8
19	0.0	64.6
20	0.0	-32.8
21	1992.0	0.0
22	1667.2	0.0
23	1045.8	0.0
24	0.0	0.0
Total	5135.2	-5135.2

Total 10270.3

Nodal Transmission Prices

Node	Generation (£/MWh)	Demand (£/MWh)
1	0.33	-0.53
2	-0.07	-0.54
3	0.00	-0.33
4	0.00	-0.92
5	0.00	-0.79
6	0.00	-1.00
7	-1.10	-1.23
8	0.00	-1.16
9	0.00	-0.76
10	0.00	-0.76
11	0.00	0.00
12	0.00	0.00
13	0.72	0.14
14	0.00	-0.17
15	0.20	0.23
16	0.18	0.08
17	0.00	0.00
18	0.03	0.08
19	0.00	0.07
20	0.00	-0.05
21	0.57	0.00
22	0.76	0.00
23	0.24	0.00
24	0.00	0.00
Total	0.33	-0.33