TRANSMISSION PRICING

by

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A thesis submitted in conformity with the requirements
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Abstract

The thesis deals with the allocation of transmission costs among the customers based on its extent of use.

Presently the electricity system in Ontario is being restructured and the transmission system becomes and independent entity that have to recover the costs it incurs through transmission prices.

The Image Domain Algorithm was the method proposed and partially developed for allocating costs and a computer program was written to apply this method to the Ontario's system. A comparison of this approach with other methods used worldwide to do this allocation is also presented, finding that this method is more clear and seems to be fear for all of the agents involved in the electricity market.

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1 INTRODUCTION

The Ontario's electricity system is going to follow the tendency of open access market that has been implemented around the world during the last few years. Thus, in the year 2000 the Ontario's electricity industry starts a process of establishing a new structure, which will allow competition under this new scheme. That process will have a transitional period of 18 months.

Under this scheme, competition will be practised in the generation sector. Because the transmission system is considered to be a natural monopoly, it must be regulated to guarantee this service will be provided evenly to all the customers and therefore to promote the economical efficiency of the whole system.

Regulation in the transmission system should cover the following issues:

- transmission expansion planning,
- connection of new agents,
- tariff structure and fees.

Under this framework, the transmission cost charged to the customers becomes an important parameter because it can be considered the control variable in the electricity system. This variable would give the proper signals to owners of generators to take decisions about location, type and time for installing their units; beyond that, it would be one of the key parameters that would define the efficiency of the market.

During the transitional period of the market, "postage stamp" transmission pricing will be employed. The transmission fees would include a charge to recover incremental congestion costs[1] and the cost of transmission losses. After that period, a locational price would be applied for each network asset and it would depend on the marginal cost at this point.

As one alternative to postage stamp pricing, Ontario Hydro Service Company (OHSC)[2] has to define a charge to the customers (initially loads), that will be applied during the transitional period, to recover the costs mentioned above, after being approved by the Ontario Energy Board[3]. This charge would be based on the usage of the transmission system by each customer.

A mathematical method that could be utilized by OHSC, for defining customer contributions to the use of transmission assets and eventually to charge costs to these users, is addressed in this thesis.

The following topics are studied in this thesis:

- principles and background of transmission pricing,
- methods for allocating contributions,
- a general method to compute shared costs,
- numerical example of allocation.

The structure and content of this thesis is presented below.

The second Chapter gives a general background of the transmission pricing issue not only from the technical point of view but also from an economical perspective. It also shows some examples of the approaches that have been or will be adopted elsewhere to deal with the allocation of costs.

The third Chapter focuses briefly on the economic point of view proposing a method to compute individual costs of transmission assets.

Chapter four covers in detail two methods to compute contributions of transmission customers (loads or generators) to line flows based on usage of individual transmission

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[1] These costs appear when the electricity demand in a given area exceeds the capacity of the transmission system to deliver it from the generators that were scheduled to provide it.

[2] The Ontario Hydro Service Company is the commercial corporation that owns the transmission and distribution systems following the break up of the former Ontario Hydro.

[3] OEB is the regulator entity under the proposed market structure.

assets. The first one called Image Domain was partially developed for this thesis to be used by OHSC and the second one, the VPX approach, is the method that is being used in Victoria, Australia.

The fifth Chapter develops an example using the principles given in the third and forth Chapters and gives a comparison of the results obtained with the two methodologies.

Chapter six describes the work carried out for OHSC using the Image Domain method.

Finally, Chapter seven presents the conclusions of this work and possible ways to overcome some shortcomings that the method developed is likely to present.

Several papers on this subject were reviewed to find out the tendencies and experiences around the world. A brief description of some of them, which are directly related to the topic of this thesis, is presented below.

1. Evaluation of Transmission Network Capacity Use for Wheeling Transactions. D Shirmohammadi, P R Gribik, E T K Law, J H Mailinowski. R E O'Donnel. *IEEE Transactions on Power Systems*, Vol 4. No. 4. October 1989. [3]

   This paper describes the MW-Mile method to compute transmission capacity use. It demonstrates that this method is more reflective of the usage of the transmission network in allocating the transmission cost than the postage stamp method.

2. Cost of Wheeling Methodologies. H H Happ, *IEEE Transactions on Power Systems*, V 9, N 1, pp 147-156, Feb 1994. [4]

   This paper presents the following four basic methods to compute transmission embedded costs, Rolled In, Contract Path, Boundary Flow and Line by Line (MW-mile) method. It also gives a description of two long run incremental cost methods and the short run marginal cost method. The main shortcomings found with embedded cost methods, the principle of which are similar to the method developed by this thesis, is that they do not consider future expansions and they do not take into account changes in production costs due to required changes in dispatch.

3. Allocation of Transmission Fixed Charges: An Overview. J W Marangon Lima. Escola Federal de Engenharia de Itajuba. Brazil. [5]

   This paper describes some methods to allocate transmission fixed costs such as MW-mile (MWM), Modulus (MM), Zero Counterflow (ZCM) and Dominant Flow (DFM) method, which are based on the extent of use of the transmission assets. The Zero Counterflow Method has the same principle as the methods addressed by this thesis in which customers who contribute with negative flow do not pay any charge. It also makes a comparison of those methods finding that the ZCM and the DFM give proper signals to the customer to reduce their flow through the transmission system. It also shows that the ZCM could lead to a great variation of the charge for a slight change of the flow.

4. The Long Term Impact of Transmission Pricing. J W Marangon Lima. Federal School of Engineering at Itajuba. E J de Oliveira. Electrical Engineering Department. Federal University at Juiz de For a. Brazil. [6]

   This paper addresses some topics about the effect of the transmission pricing methods on system costs in the new environment where generation is treated as an open market and transmission as a monopoly. It considers Long Term Marginal Cost (LTMC), Short Run Marginal Cost (STMC) and embedded cost methods like postage stamp (PS), module method (MM) and dominant flow method (DFM). Since the LRMC is difficult to calculate, the challenge is to design allocation rules, which promotes the least deviation from the optimized total cost. This paper stress the necessity of trying good approximations of LTMC that take into account the dynamic aspects, regulation constraints and system characteristics.

5. Open Access and Network Services – A Global Approach. Anthony S. Cook, Brisbane, Australia. Hyde M. Merrill. Schenectady, New York. Power Technologies, Inc. [7]

   This paper presents some methods for developing the long run marginal cost of transmission and for pricing stand-by and top-up electricity supply. The LRMC is obtained based on the curve of costs of past and planned transmission investments versus usage, where the approach to measuring transmission usage is a simplification of the "MW-mile" method.

6. Revenue Reconciled Optimum Pricing of Transmission Services. BLPP Perera and ED Farmer BJ Cory. *IEEE Transactions on Power Systems*, Vol. 11, No. 3, August 1996. [8]

   This paper describes a methodology for evaluating an optimal set of transmission prices, to be charged for use of a transmission system on a time of use basis and those circuit prices are applied as nodal prices in proportion to the power injected and extracted from each node.

The method presented in this thesis is also based on the extent of use of the transmission system as some of the methods given by the references [5] and [6], but the approach used was different. This approach has not been used anywhere before.

2. NETWORK COSTS FOR THE EHV TRANSMISSION NETWORK

2.1 Introduction

As long as transmission is vertically integrated with generation, the separate pricing of transmission is not a concern, since there is no need to unbundle costs. The system is optimised with finding the minimal total cost that already includes transmission costs. Besides, in most integrated systems, the knowledge of cost is used to minimize the total cost of building and operating generation and transmission, not to set prices.

However, as we move to competition, the transmission system is usually unbundled from generation, and will usually be operated by a "transmission system operator". Therefore, transmission prices become more important for the operator to charge for its services.

The product provided by a transmission system is a transport service: the movement of electricity, from one named point on the network to another, at the request of a system user. This product is supplied using a variety of inputs as lines, towers, cables and other hardware, and also a range of ancillary services such as reactive power (voltage control) and reserve generation (frequency control).

The first part of this chapter provides a brief background about transmission pricing considering objectives, costs and charging. Then it describes a general method used for charging transmission services and finally it describes some aspects of the regulation and the charging cost method that is likely to be applied to the transmission system of Ontario.

2.2 Objectives for Transmission Prices

The most commonly quoted objectives of transmission pricing under an open access market are listed below:

Economic efficiency

This objective requires prices to give the correct signals in four key areas: location of new generation and demand; use of the network by system users; operation of the network by the transmission system operator; and development of the network.

Revenue sufficiency

For any transmission company, this objective is paramount. Transmission companies have little or no interest in taking on risk, which means that they are mainly concerned with recovering all the costs incurred in building and operating the network.

Efficient regulation

Since most of the transmission system operators are natural monopolies, they need to be regulated. Efficient regulation should encourage minimum-cost operations by means which keep intervention of the operator to a minimum.

There are some other objectives for transmission prices such as stable prices, a commitment to provide equitable terms for access, and other social objectives which affect prices.

2.3 The Cost of Transmission Service

Each individual user of the system requires a slightly different service, since they specify different points of entry and exit, different time periods when service is needed, and different quantities of energy to be moved in each period. The costing methodology must therefore define, as far as possible, the service offered to each electricity user of the system and identify the cost imposed by the use of the system.

Providing transmission services may involve the following costs:

- building capacity (including recovery of sunk costs);
- marginal losses; and
- congestion

2.3.1 Building Capacity Costs

Transmission networks are large capital-intensive investments and require fixed assets that are essentially immovable or not re-marketable. Once they are placed in service the carrying charges for transmission infrastructure remain essentially constant, even if usage of the system varies considerably. This is what is meant by "sunk costs".

2.3.2 Marginal Costs Losses and Congestion

Marginal costs are all costs, present and future, imposed on the system by an increment of use.

Short-run marginal cost (SRMC)

This is the cost of increasing output to meet an increment in demand when the system capacity is fixed. In a transmission system the short-run marginal costs are the energy costs of losses and constraints.

In the short run, the transmission costs consist of energy costs. Additional energy flows over a network change total physical losses. The cost of the incremental losses is a short-run cost of transmission. The additional flow may also tighten constrains on the system, causing some generators to be backed off, while more expensive generation is dispatched to match the demand. The net cost of these adjustments to dispatch is another short-run cost of transmission.

An electricity system suffers from three major types of constraints: thermal limits, voltage limits and stability limits, which may cause the system to increase the generation cost. This drives a wedge between the marginal cost of generation on either side of the constraint that exceeds the value of marginal line losses.

2.4 Recovering Cost of Transmission Service

The cost of building new capacity normally reflects the economies of scale which seem to be present in most investment projects. If there are economies of scale, spot pricing of transmission will not recover the cost of the link.

Economic theory says that efficient prices should be set at marginal cost to give a correct signal of consumption to the user. Unfortunately, in transmission systems where there are common costs caused by economies of scale, marginal costs are usually substantially lower than the average costs and the revenues from pricing all requests for service at marginal cost will not recover the total cost of providing the service. Therefore, if prices are set at this level, the network owner will not recover total costs of new investment and eventually the business would not be viable.

The general rule for efficient investment is that total incremental revenues should be high enough to cover total incremental costs. This will discourage investments that customers jointly would not be willing to pay for. The associated pricing policy is: to set prices to individual customers no lower than the marginal cost of serving each customer and no higher than their willingness to pay; and to ensure that total revenues from all customers are not lower than total costs.

For example, the technology may have a cost function of the form:

Total cost of expansion by x units = $k + bx$,

where k includes the cost of establishing planning permission and rights of way, hiring contractors, and laying down the basic foundations for providing a transmission link, and

b represents the steel, aluminium and other materials required to carry 1 MW over the route concerned.

The marginal cost of expansion is b, but it is not rational to make the investment, unless customers are willing to pay the common cost, k, as well.

Providing it is rational to make the investment, the general pricing policy is to ensure that the cost of k is allocated to customers in a way that does not distort the investment decision, by loading common costs onto the customers most willing to bear them.

Because of the high risk involved in relying on marginal costs, most regulators prefer to impose a pricing system which is closely linked to actual cost incurred, rather than the short run value in the market. In many systems, therefore, regulators and regulated alike prefer to set prices equal to the accumulated sunk cost $bx(1 + r)^t$, where r is the interest rate or discount rate and t is the time lag between the time when the capacity was created and now, rather than short-run marginal costs. In a risky environment, the price might fall as low as the short run marginal cost of using the capacity at which level they would fail to recoup the accumulated cost of construction.

The following sections describe specific methods for charging sunk costs, new investment cost, losses and congestion costs and how those costs can be reflected in the total transmission prices.

2.4.1 Sunk Costs

Sunk costs, which exist no matter how network users respond to the pricing signals, could be recovered also through additional charges.

The principle of marginal cost pricing leads to the conclusion that the sunk costs or residual revenue of the network (capital cost plus the unavoidable maintenance costs) should be recovered through a lump sum that doesn't distort the locational and congestion signals that exist or are being created in most of the electrical markets.

On the other hand, the beneficiary pays principle, establishes that if a person benefits from using the network then that person should pay an appropriate proportion of the cost.

However, economic theory explains that the most efficient pricing mechanism provides marginal cost signals to users and then recovers the sunk costs in the least distorting way with a special charge.

Transmission companies need to ensure that they are able to recover all the costs of long-term investments, even though future demand for transmission capacity remains highly uncertain. The following are the most popular methods:

Regulated monopoly network

Transmission companies can recover their sunk costs via annual tariffs, by spreading them over a captive market.

Long-term capacity contracts

Every system user could agree to pay the full cost of investment carried out on their behalf, and in return they would receive a long-term right to use any capacity created by their investment.

Termination payments

Charges paid when quitting a connection are another way of ensuring that system users pay off the full cost of facilities built for their benefit.

2.4.2 New Investment Costs

Marginal costs have been found to be inappropriate signals for new investments.

The planning of new investment in the network must take into account requirements of both generation and demand. New investment will also benefit both sides: customers through improved system reliability and security; and new or existing generators through reduced losses or a lower level of constraints. These costs should be paid by those who benefit from the new investment in order to promote efficient locational decisions.

There are two main options for determining the appropriate share of the costs of new investment to be met by generators and customers: connection charges for generators and share of benefits to the demand and supply sides respectively as a result of a specific investment.

Connection charges include the short run marginal costs and additional signals for those circumstances where short run marginal costs will not provide an effective signal.

The alternative is to establish a framework to identify the share of benefits to generators and customers respectively as a result of a specific new investment in the network.

2.4.3 Actual or Expected Losses

There are in general two ways to incorporate losses costs in transmission pricing:

- charge users for the actual, real time marginal losses imposed by their usage; or
- charge users a fixed kWh price for transmitting energy over the network.

Real time pricing of losses will encourage efficient use of the network, but is difficult to implement on a transparent and non discriminatory basis. On the other hand, a fixed price may or may not reflect the actual cost of losses very accurately.

2.4.4 Congestion Costs

Congestion costs should be reflected in the terms of transmission costs, to avoid excess of demand for transmission services over congested parts of the network.

The constraint costs can be reflected in transmission contracts in three different ways:

- by withdrawing transmission capacity according to some agreed protocol when constraints occur, so that system users must adjust their trades in energy,
- by charging an explicit "bottleneck fee" for each kWh that crosses a constraint, so that system users pay more for scarce capacity,
- by including an allowance for the costs of redispatch in kW payment for transmission capacity.

This thesis discusses a methodology for computing the allocation of sunk costs and new investment costs among users.

2.5 A General Approach to Charging Transmission Prices to Recover Network Costs

Once transmission costs are defined, they must be recovered through charges applied to network users, such as the Distribution Businesses, large EHV Customers and generators. The design of this economically efficient pricing structure for transmission must be consistent with the requirement to recover sunk costs in an equitable manner.

This section describes a general method for computing and charging transmission fees.

A general method for charging the use of the EHV transmission network can be summarized as follows:

1. The owner of the transmission company charges the operating company for provision of the shared network as a whole (***the Network Charge***).
2. The operating company charges distributors, generators and any EHV customers for use of the shared transmission network (***Charges based on usage of the network***).
3. The owner of the transmission company charges distributors and generators directly for dedicated connection assets such as power station switchyards and load supplying terminal station transformers (***Entry and Exit Charges***, respectively).

Figure 2.1 shows the manner in which the charges could be transacted between the parties based on a scheme adopted in Victoria [1].

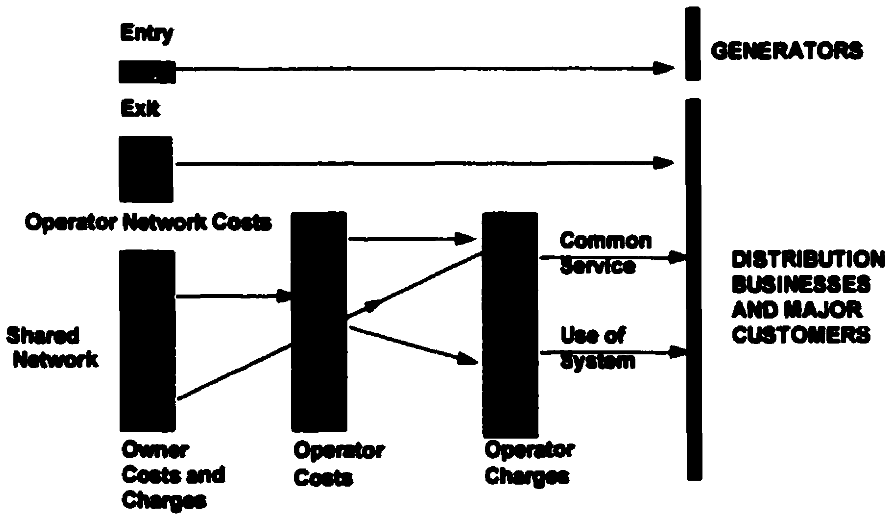

Figure 2.1. Transaction of Network Charges

2.5.1 Network Charge

The Network Charge could be separated into two components:

- the total charge to apply to shared network assets which should be recovered on a locational basis through the Locational Component of the Network Charge; and
- a common service charge which covers the costs which it is not appropriate to recover on a locational basis, e.g.: Reactive plant, administration, non operational land holdings etc.

2.5.2 Charges Based on the Use of Transmission System

The locational component of the Network Charge could be allocated to users on a cost reflective basis using one of several possible algorithms. Two of those algorithms are discussed in Chapters 4 to 6 of this thesis.

2.5.3 Common Service Costs

Common Service Costs are those costs not appropriate to recover on a locational basis. These costs include the asset related costs which do not provide a locational service together with a number of administrative and overhead costs.

There can be identified four components of the Common Service Costs.

1. The non locational based costs associated with the network assets including:
   - provision of reactive control plant (capacitors, static Var compensators and synchronous compensators);
   - communications equipment;
   - non operational land holdings;
   - spare plant and equipment; and
   - administration and overheads associated with the network.
2. Network related costs including the following:
   - recovery of the costs of control centres and control equipment owned by the operating company;
   - network operations by the operating company;
   - network design overheads;
   - additional costs associated with risk, for example through insurance premiums; and
   - working capital requirements for network fees.
3. Any net settlements which would be payable by or to the operating company to or by network owners in other jurisdictions reflecting the application of the cost allocation process to parts of the trasmission network belonging to the outside utilites, and

4. Any under or over recovery of revenue which resulted to the operating company in the previous year from application of the usage based charges are included in the common service charges in the following year[4].

The common service costs can be recovered, where applicable, from users using a postage stamp charge[5]. The network related costs include also insurance premiums for "operating company" risk.

2.5.4 Entry and Exit Charges

These connection charges are applied to those users who directly benefit from assets that are installed.

2.6 Allocating Transmission Costs in Ontario (OHSC)[6]

This section describes the possible methods for allocating transmission costs which would be applied in Ontario after the open access market starts operating [2].

From Ontario Hydro Service Company's perspective, there are two possible ways to bill end-use (retail) customers of Local Distribution Companies (LDCs)[7] for transmission services through a network charge:

1. End Use (Retail) Option: The transmission services provider could set the charges for all retail customers, in accordance with an Ontario Energy Board (OEB)[8]-approved method, and the LDC would simply collect this charge on behalf of the provider.
2. Wholesale Option: The LDC could pay an OEB-regulated charge to the transmission services provider at the wholesale level (the transmission/ distribution interface) and then recover these costs from its customers, under a separate OEB-approved method.

On the other hand, the incremental costs of congestion and transmission losses would be paid initially by all load customers in Ontario under an averaging method. After 18 months a

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[4] Items in category 3 and 4 may be negative, i.e. result in a cost reduction.

[5] This is a uniform transmission charge.

[6] Ontario Hydro Service Company. This is the transmission system owner in Ontario.

[7] A Local Distribution Company is an entity that owns a distribution system for delivery of energy to consumers from the IMO controlled grid.

Locational Marginal Pricing scheme would be introduced in which the energy price at any location on the integrated network would depend on the marginal cost of delivering the energy at that location.

The following subsections describe the application of the transmission charges independently of how the customers would be billed.

2.6.1 Transmission Service Charges

It can be generally stated that those who use and benefit from transmission facilities (assets) should pay for them. Inappropriate allocation of transmission service costs would unfairly shift the burden of providing these services to those that do not use or benefit from them. One customer group should not be required to subsidize another.

As a first step, all transmission service costs could be allocated into one of three categories:

- network service,
- line connection service, and
- transformation connection service.

These categories may be allocated in a locational basis. This would help to identify which customers use and benefit from the facilities needed to provide the respective services, so that their costs can be appropriately assessed. The overall Network Charge should be set by the allowable revenue approved by the regulator entity.

2.6.2 Charges Based on the Use of the Transmission System

This section discusses various methods for determining how the costs of the three service categories could be fairly allocated. The options include:

1. Customers could be assessed charges on the basis of which delivery points supply their load, with common transmission-related costs assessed on all load customers.

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[8] The Ontario Energy Board establishes the conditions for licensing market participants, and regulates revenues and sets rates for transmission and distribution companies.

2. Generators could be assessed charges for assets used to deliver their output to the commonly-shared network. The costs of the common network assets could then be assigned to all generators and/or all load customers.
3. Transmission service pools would group transmission assets by function. All transmission costs would be allocated to one of these pools and paid for by generators and/or load customers.

The major components of the total transmission revenue requirement are operation, maintenance, and administration costs; depreciation; interest expenses; regulated net income; and income taxes.

Any revenue requirements associated with providing transmission services must be allocated in such a manner that (a) only the costs associated with the provision of the transmission service are collected from the transmission users; and (b) the corresponding charges are collected only from those using the specific services, if such services can be identified distinctly.

Allocation methods

For the purpose of assigning the responsibility for the transmission costs, transmission assets and their associated revenue requirements can be allocated among the users of the transmission system in several ways. The following briefly describe some of the allocation methods that can be used, either individually or in combination with other methods:

1. Each delivery point from which load is supplied can be assigned a share of the transmission assets that are utilized to supply the load, based on forecast or actual load and generation patterns. The load customers could then be assessed charges on the basis of the assets used to supply their delivery points. Common transmission-related costs could be assigned to all load customers.
2. Each generator can be assigned a share of the transmission assets that are utilized to carry power from that generator to the network or commonly shared assets or, if applicable, to the delivery points from where the load is supplied. Generators could then be assessed transmission charges on the basis of the assets utilized to carry their output. Common costs may be assigned to all generators and/or all load customers.

3. The above methods, or their variations, can be used to develop more spatial (for example, locational or zone-based) allocation of transmission costs.
4. Transmission service pools can be created to group assets that are used to provide similar functions. An appropriate share of the total transmission revenue requirement can then be allocated to these pools. The load customer and/or generators can then be assigned responsibility for the costs allocated to these pools.

Allocation of transmission revenues to pools

The following steps outline one possible approach to allocating the transmission revenue requirements to three pools or service categories.

1. Transmission assets and their Net Book Value (NBV)[9] may be allocated to one of the three service pools:
   - Network Service Assets would include the lines and stations owned by OHSC that are fulfilling the role of inter-area transmission interconnection within Ontario and with neighboring utilities. These would comprise all the extra-high voltage (500 kV) lines and stations, most of the 230 kV and 115 kV lines, and the 230 kV stations that are not dedicated to the use of specific beneficiaries.

     These facilities connect large generating stations and major load centers to each other. Any assets used for system operation, such as the Transmission Operations Management Center (TOMC) in Etobicoke and major capacitor banks used to provide voltage support would also be classified as Network Assets.

     Although new interconnection may be financed through the "user-pay" principle, it may be appropriate that existing interconnections be deemed to be shared by all, especially since they were built by the former Ontario Hydro to provide economic and reliability benefits for the province.
   - The Transformation Connection Service would include all OHSC-owned transformation (delivery point) stations that link DCCs and LDCs to the transmission system.

[9] The Net Book Value is a financial accounting concept defined as the historical cost of placing an asset in service less the accumulated depreciation of the asset.

- The Line Connection Service would include all OHSC-owned lines and intermediate stations used to connect the above noted transformation stations to the transmission network.

The NBV of the transmission business assets that cannot be directly allocated to the three service pools would be allocated to these pools as a proportion of the Net Book Value of the assets that have been directly allocated as above.

2. Depreciation costs for those assets specifically allocated to each service category would be allocated directly to that category. The depreciation cost for any *unallocated* assets would be allocated to the three service categories as a proportion of the total Net Book Value of those assets that are specifically allocated.
3. The regulated net income, income taxes and interest charges would be allocated to the three service categories as a proportion of the Net Book Value of the assets allocated to each corresponding service category.
4. Service Level Agreements and other processes would be developed, to be used in conjunction with the existing Uniform System of Accounts used to track OM&A costs. The goal is to accurately allocate transmission-related OM&A costs to each of the specific service categories of Network Pool, Line Connection Pool and Transformation Connection Pool.

   The process of allocating costs to rate pools will be a manual process, based on an after-the-fact analysis and reconciliation of costs.

2.6.3 Who should be charged?

The component of the three categories of service in Ontario, which could be recovered in a locational basis is allocated to customers by means of a usage reflective algorithm.

At present, load customers pay all those Network Pool services charges and if applicable, the existing Line Connection and Transformation Connection Pool charges, as is the case in most jurisdictions neighboring Ontario.

This section discusses the implications of shifting all or part of the cost of transmission services to Ontario generators. OHSC's position is that this should not happen in the case of *existing transmission network* assets. The main reasons for this conclusion are that this cost shift would:

- make Ontario generators less competitive compared to those outside Ontario;
- distort the IMO-administered energy market because "hidden", fixed transmission costs would be included in the price of energy;
- result in some customers paying unfairly higher transmission costs than others

The issue of whether or not generators should pay *existing connection service* charges is relatively more complicated, since a decision on this matter could impact differently the generators that are assessed these charges and those generators that may not be required to pay these charges.

A concern that bears on this issue is that generators that do not pay transmission charges would not have any price signals or incentives with respect to siting new generating plants or new transmission investments that may be required. This concern may be addressed somewhat by the fact that the new investment rules recommended by the MDC provide for assessing costs to the beneficiaries. Thus, owners of specific generators would have to pay for part or all of any new transmission investments that are deemed to benefit them.

If generators were to pay some of the transmission charges, it would reduce the transmission charges directly assessed on load customers. However, in this case, the generators would include some or all of the transmission costs they pay in their energy prices. Therefore, there may not be a one-to-one benefit for load customers if generators were assigned the responsibility for transmission costs.

To ensure that domestic generators compete on a level playing field with out-of-province generators, one option would be to not have Ontario generators pay Network Pool service charges. It may be appropriate and fair however, to allocate some charges to generators using the connection facilities, especially from the viewpoint of other generators that do not use Line Connection services.

2.6.4 Common Service Costs

The costs of OHSC's Shared Functions and Services would be allocated to the Transmission business on the basis of:

1) Causality, where possible; and
2) Benefits, where no causal relationship can be identified or provided. This allocation takes into account the concern of unfairness as a result of cost-shifting from non-transmission and non-regulated activities to the regulated transmission business.

The Shared Functions and Services costs would then be allocated among the three service pools (Network, Line Connection, and Transformation Connection) as a proportion of the NBV of the assets allocated to these pools.

OHSC Shared Functions and Services comprise: Corporate Office, Finance, Human Resources, Corporate Relations, Information Management, Planning & Development, Health and Safety and Year 2000 Office.

2.6.5 Exit Charges

In the open access market, some customers would prefer to disconnect from the transmission system and take generation from a local distribution company in order to avoid paying sunk cost. This could be even more expensive for the whole system than the previous connection, even though this customer pays a lower charge.

An exit charge may be created to discourage customers to disconnect from the transmission system and to pay those sunk costs which would not be recovered due to the disconnection.

3 ALLOCATION OF COSTS ON A LOCATIONAL BASIS

3.1 Introduction

A locational basis allocation to each Terminal Station which supplies load to the DB's and EHV customers or to each generator, may use one of the methods that reflect the usage of the network by these customers, available for this purpose. This allocation can usually be based on the use made of the transmission network by each Terminal Station over the peak of the period of maximum demand in the previous year and the cost associated with individual network elements which are required to provide the service. The allocations convey the cost of providing network service to each Terminal Station (primarily asset related) based on an asset cost assignment method appropriate for each company.

Even though, most of the current electrical markets distribute the Locational Component of the Network Charge just among loads, the methodology discussed here covers allocation to loads and generators. The introduction of a firm access market for charging generators for use of the transmission network would reduce the share of charges paid by loads.

In order to allocate the costs associated with the usage of a particular transmission facility to the customers, the cost of each facility needs to be determined first. This is followed by splitting this cost between customers. These two issues are briefly discussed in the remainder of this Chapter. A more detailed description of the various algorithms introduced in this Chapter is given in Chapters 4 to 6.

3.2 Determination of Individual Asset Costs

The usage based cost allocation method is an asset based process. To start with the process of allocation it is necessary to determine the annual revenue which is required to be earned from each individual network asset to cover the costs of providing, operating, maintaining and planning the shared EHV transmission network.

In Victoria, Australia for example the cost allocation is carried out based on a nominal optimised network[10] consistent with the valuation of the system assets[11] [1]. The cost for each individual asset in the optimised shared network is determined by allocating the Locational Component of the Network Charge to individual assets pro-rata with their gross replacement value in the optimised network valuation.

The cost allocation is a nodal based method and therefore requires all of the costs to be attributed to the branches between nodes on the EHV network. Thus the station termination costs are allocated to the lines so that the cost of a "transmission line" includes:

- the cost of the line;
- the cost of the circuit breakers at either end of the line[12];
- Main system tie transformers, such as those between two EHV voltage levels are treated as lines.

Using this approach all station costs are allocated to lines (and tie transformers) except for reactive plants and associated switchgear. These costs are recovered through the common service charges.

In the Ontario System, the cost allocation may be also a nodal based method requiring all the costs to be attributed to the branches between nodes on the EHV network. In this case, each

[10] The determination of the annual revenue requirement is based on an optimised network, where assets may be written down or replaced with assets of lower value where a more economic arrangement would provide the required service. This "optimal network" is also used for the cost allocation to avoid the allocation of network elements which are not required to provide supply to the particular load point.

[11] After an optimisation of the network is carried out at the asset level, those assets which were optimised out of the asset base are identified. The cost allocation is carried out on the nominal network which included the assets which remain in the optimised network.

[12] Circuit breaker costs include the secondary protection and control equipment and establishment costs of the equipment, i.e. circuit breakers include costs for standard bays with isolators, CTs, VTs and the bus work.

asset cost would be assigned to one of the categories mentioned in the last chapter: transmission network, transformation connection or line connection.

3.3 Cost Allocation

The cost allocation process involves allocating the individual network costs associated with each station to those participants who use them.

The cost allocation methods addressed in this thesis are load flow based methods. The following sections give a general explanation of the method used in Victoria [1] and an alternative method proposed for the Ontario system, developed as a part of this thesis.

3.3.1 Victoria, Australia (VPX method)

The cost allocation requires detailed load flow analysis of the system and its operation. The costs are allocated for each network element as described above, and the use of the network elements by each participant is calculated by the allocation method which determines the share of each element used by each load.

In order to determine this, it is necessary to define the generation source which supplies each load point. Once this is defined, the actual flows on individual elements in the network resulting from transfer of power from the designated group of generators to each load point can be determined by network analysis techniques. The share of each network element used by a particular load is then simply the flow on the element resulting from the supply to this load expressed as a ratio of the total use made by all loads in the system.

The generation source for each load is defined using the "electrical distance" as a measure of the capability of a generator to supply each load point. Using this approach a greater proportion of load at a particular location is deemed to be supplied by generators which are electrically close than those which are electrically remote. In electrical engineering terminology the "electrical distance" is measured by the impedance, and this can readily be determined through a standard engineering calculation called the "fault level calculation".

The use of the network element by each generator can be calculated by an analogous allocation method which determines the share of each element used by each generator.

The use made of the network by particular loads or generators will vary depending on the operating conditions on the network. For this reason a number of operating conditions should be examined with different load and generation patterns. Since the intention is to obtain prices which provide appropriate signals for investment in the network, the cost allocation is carried out using actual load and generation data for a recent period of high demand, using hours with relatively high network loading.

The following steps are carried out once for all operating conditions:

1. Attribute network costs to network elements.
2. Determine the fault contribution matrix to allocate generation to loads.

The following steps are carried out for each of the operating conditions being considered.

3. Determine constrained allocation of actual generation to loads.
4. Calculate line flow contributions of each load.
5. Calculate relative utilisation by each load of each network element.

The steps below are carried out when all operating conditions are complete.

6. Determine the share of each network element required by each load.
7. Allocate network costs to each load.

A detailed explanation of these steps is given in chapter 4.

3.3.2 Ontario System (OHSC)

Some methods to allocate cost among users have been studied and one of them called "Image Domain" has been partially developed for this thesis and applied to OHSC system. Similarly to the VPX method, the Image Domain algorithm is based on the use each customer of the transmission system does of each transmission asset.

The algorithm uses the concept of *the image domain* of a branch and proportional split of power flow based on load flow studies for a given trading interval. The algorithm can start from any branch which does not have to be the one connected to a source node. The algorithm can compute both contribution of power generated to flow in each transmission line and the use of every line by each load.

The following summarizes the steps of the process:

1. Attribute network costs to network elements.

For each operating condition:

2. Determine the share of each network element required by each load or by each generator.

After all operating conditions have been considered:

3. Allocate network costs to each load.

A detailed explanation of these steps is also given in chapter 4.

3.4 Operating Conditions for Cost Allocation

Because these methods are based on AC load flow results, the obtained allocation corresponds to a snapshot of the system operation. In order to cover the most critical scenarios, it is necessary to analyse different operating conditions of the system and find an average allocation.

The operating conditions to be used for the cost allocation process could be defined as follows:

- load and generation conditions to be actual operating conditions from the previous financial year;
- operating conditions include a percentage (%) of hours with highest maximum demand over the most recent period of high demand;
- the period chosen broadly corresponds to the times at which high demands drive network expansions.

3.5 Cost Re-allocations

Cost re-allocations are required on a periodic basis to include additional network investment since the previous period and to capture any significant variations in use of the system (perhaps in response to the pricing signals). This re-allocation process can in itself provide some pricing signals, however it is important that these do not distort the basic pricing signals provided through the pricing structure.

It is proposed that the cost re-allocation be carried out using a cycle consistent with the proposed regulatory review period. In between the cost allocations, all prices would be scaled to reflect the current revenue requirements of the electrical companies to be recovered through transmission prices.

The re-allocation process in Ontario has not been studied yet.

4 COST ALLOCATION METHODS BASED ON USAGE

4.1 Introduction

Several methods have been studied and developed for this thesis to carry out the allocation of the individual asset costs among the loads or the generators using the network. This chapter covers the detailed description of the image domain algorithm which was partially developed for this thesis, as well as the VPX algorithm which is the method used by the Victoria Power Exchange in Australia. It also describes briefly the UMIST approach that is based on the same assumptions as the image domain with some variations.

4.2 The Image Domain Algorithm

The Image Domain algorithm has been developed for determining asset utilization in a transmission system. For the purpose of this development, the assets are defined as high voltage transmission lines, power transformers and selected high voltage buses.

The aim is to produce tables showing the relative Utilization Share of (Individual) Transmission Assets (USTA) for each load and each generator of the transmission system.

The proposed algorithm computes USTA in the following steps:

1. **Attribute network costs to network elements**
2. **Determine the share of each network element required by each load or by each generator**
3. **Allocate network costs to each load or to each generator**

This section addresses only the second step of the USTA procedure.

4.2.1 Concepts

The algorithm uses the concept of *the image domain* of a branch and a split of power flow based on Kirchoff's law and a proportionality principle. Since a solved load flow is used as a basis of the computations, no impedances are required. The impedances of the lines and transformers as well as network connections are already reflected in the power flows in the system elements.

The flow on a line can be attributed to loads only, generators only or loads and generators. Depending of the policy defined by the electrical system regulator, one of these approaches is chosen. The current algorithm can calculate both contribution of power generated to the flow in each transmission line and the use of every line by each load. Additionally, the procedure can determine the contribution of each generator to every load.

This section consider two algorithms to address these approaches:

- load contribution to line flow,
- generator contribution to line flow,

Image Domain

An image domain of a given line includes all the branches connected to the sending bus[13] of this line that contribute to the flow in this line. A line can also have a delivery point or a generator in its image domain. This happens when the load at this delivery point or a generator contributes to the flow in this line. To illustrate this concept, consider a single bus of a larger network shown in Figures 4.1 and 4.2.

[13] Each branch will have a sending and receiving bus. The sending bus is one with positive flow in the line under consideration. The sending bus can be different from the "from" bus as defined in the load flow table.

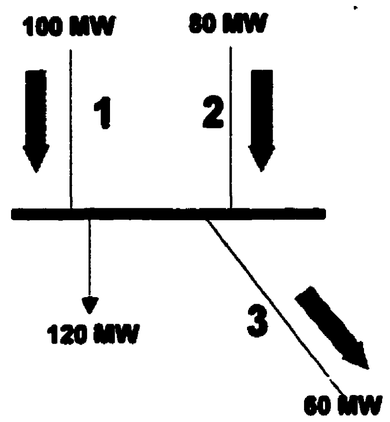

Figure 4.1. Illustration of the concept of image domain for loads

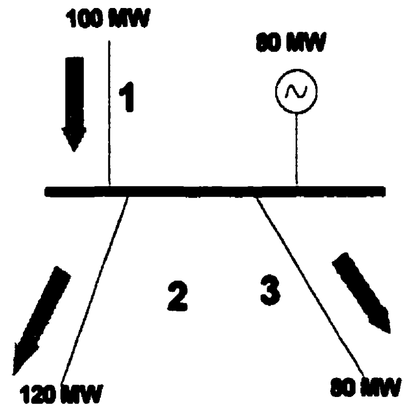

Figure 4.2. Illustration of the concept of image domain for generators

Referring to Figure 4.1, line 1 is in the image domain of line 3 since the flow in line 1 contributes to the flow in line 3. Similarly, line 2 is in the image domain of line 3. On the other hand, line 3 is not in the domain of line 1 because line 1 is "up stream" from line 3. Also, load L is in the image domain of lines 1 and 2 but not in the image domain of line 3. A formal definition is given later in this section.

Considering now contribution of generators to line flows and referring to Figure 4.2, we observe that line 1 is in the image domain of lines 2 and 3 since flow in line 1 contributes to the flows in lines 2 and 3. On the other hand, line 3 is not in the domain of line 1 because line 1 is "up stream" from line 3. Also, generator G is in the image domain of lines 2 and 3 but not in the image domain of line 1.

A major part of the load contribution algorithm involves determination of the proportion of the flow in a given line L that can be attributed to the flow in line K "up stream" of line L.

Assume that both lines are connected to the same bus i and the flow in line K is towards bus i while the flow in line L is away from that bus (in other words, line K is in the image domain of line L). Computation of this contribution will utilize the following *proportionality* assumption [2]:

For a given bus, if the proportion of the outflow, which can be traced to load L_i is x_i, then the proportion of the inflow traced to load L_i is also x_i.

This assumption provides the basis of a recursive algorithm for determining the contribution of each load to the flow in each line. A brief discussion of the implication of this assumption is presented in Appendix A. The concept of the proposed attribution method can be explained by referring to the system in Figure 4.1.

For example, for the 60 MW flowing in line 3, it is necessary to calculate how many MW come from line 1 and how many from line 2. On the basis of the proposed algorithm, one third of the flow in line 1; that is 33 MW, goes to supply line 3 and one third from line 2; that is 27 MW, also goes to supply line 3. This means, that 67 MW of the flow in line 1 go to supply the load or, in other words, the load contributes 67% of the flow in line 1.

A more detailed description of the algorithm together with numerical example is given in the following sections. The algorithm can start from any branch and the starting branch need not be one connected to a source (generator) node.

By analogy, the generator contribution algorithm consists in the determination of the proportion of the flow in a given line K that can contribute to the flow in line L "down stream" of line K. In this case, computation of this contribution will be based on the following *proportionality* assumption:

For a given bus, if the proportion of the inflow, which can be traced to generator G_i is y_i, then the proportion of the outflow traced to generator G_i is also y_i.

This is the assumption used in the algorithm which determines the contribution of each generator to the flow in each line. The concept of the proposed attribution method can be explained by referring to the system in Figure 4.2.

For example, for the 80 MW flowing in line 3, it is necessary to calculate the quantity of MW that come from generator G. On the basis of the proposed algorithm, 44.44% of the flow in lines 2 and 3, that represent 53.33 MW and 35.52 MW respectively, are the contribution of the generator G.

The flowchart of the algorithm is shown in Figure 4.3. The input data determines power flow in each line (from the beginning and from the end) and the structure of the transmission system.

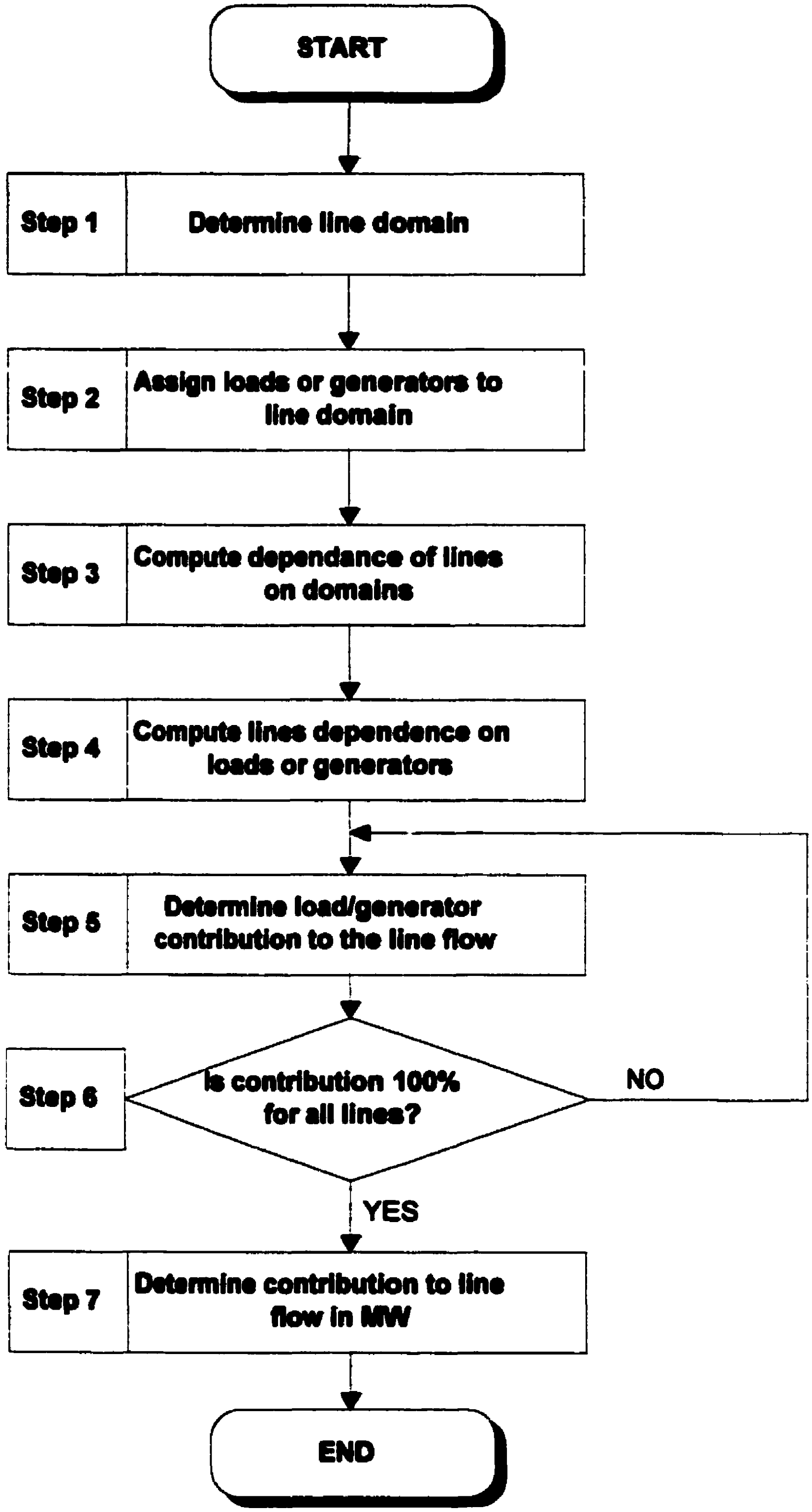

Figure 4.3. Main flow chart of the image domain algorithm

4.2.2 Load contribution to line flow

We will consider all branches with the direction of the flow taken into account (a branch is a line or transformer). To further illustrate the meaning of the concepts introduced in this chapter, let us consider a small test system shown in Figure 4.4. The line flows are obtained from an ac load flow solution and the positive directions of power flows are shown in the figure. A complete load flow solution is presented in Table 1. The first step of the algorithm is to determine the image domain of each line as illustrated below. The data are given in the per unit system.

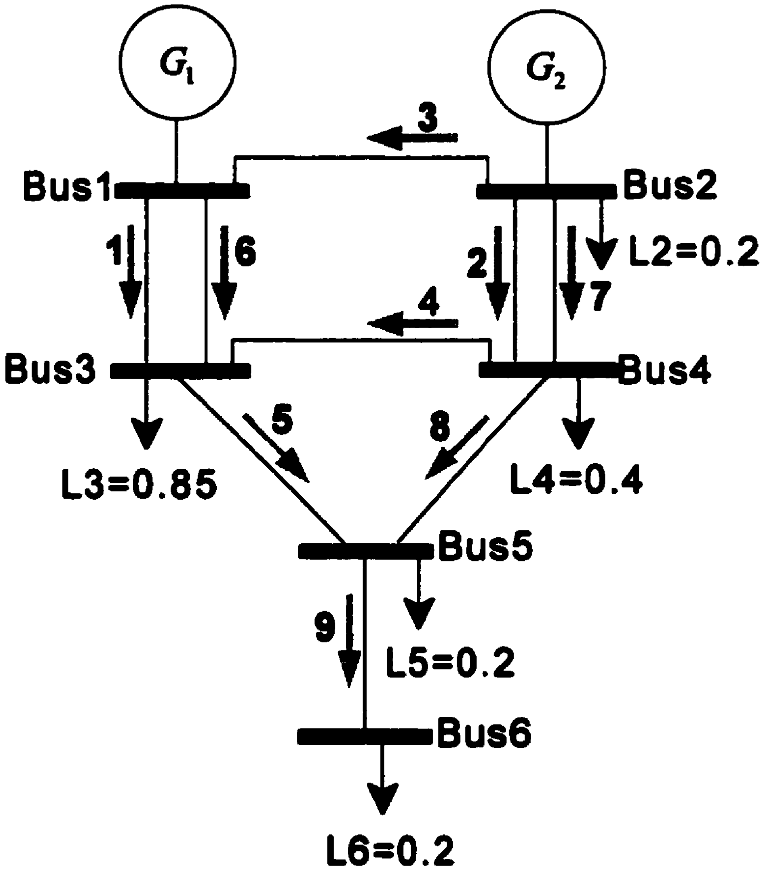

Figure 4.4. The test system (Image Domain)

Table 4.1. Load flow solution for the system shown in Figure 4.4

	Voltage				Power flow from	
Bus/Line	Magnitude in p.u.	Angle in radians	Bus *i*	Bus *j*	bus *i* to *j* (p.u.)	Bus *j* to *i* (p.u.)
1	1.05000	0.00000	1	3	0.489	–0.481
2	1.05000	0.12686	2	4	0.358	–0.345
3	1.03059	–0.08011	1	2	–0.277	0.284
4	1.02879	–0.07284	3	4	–0.060	0.060
5	1.02566	–0.09934	3	5	0.172	–0.171
6	1.02508	–0.11530	1	3	0.489	–0.481
7	–	–	2	4	0.358	–0.345
8	–	–	4	5	0.230	–0.229
9	–	–	5	6	0.200	–0.200

Swing bus (bus 1) power generation required = 0.701 p.u. Generator 2 output 1.2 p.u.

4.2.2.1 Determination of image domain

To determine the image domain of a branch, we will need to examine the flows in all lines connected to the sending end of this branch. The complete algorithm for the determination of image domain is as follows:

```
Do for each bus i
find the lines connected to bus i
end Do
Do for each line L connected between buses i and j
    if power flow is from Bus_i to Bus_j then
                Do for each line K connected to Bus_i
                  if the flow in line K is towards Bus_i then
                        Line K is in the line domain of line L
                  endif
          end Do
                If Bus_j is a load bus then the load is in the domain of line L
    else
          Do for each line K connected to Bus_j
                if the flow in line K is towards Bus_j then
                      Line K is in the domain of line L
                endif
           end Do
                If Bus_i is a load bus then this load is in the domain of line L
   endif
end Do
```

An application of this algorithm gives the results shown in Table 4.2. For a given column L, all rows with nonzero values identify the lines in the domain of line L. The table is read as follows. For a given column L and row K, the number represents the maximum flow in line L that could be attributed to the flow in line K. This value is equal to the flow in line L taken from the load flow table. The actual attribution is computed later and this table is used only to identify line domains and check the upper values of the contributions.

For example, the last row corresponding to Line 9 has all zeroes since Line 9 does not contribute to power flow in any other line "down stream". Line 9 supplies only load L6 equal to 0.2 p.u. Line 8 and Line 5 can contribute to flow in Line 9; therefore in the rows corresponding to these lines there is a number equal to 0.2 in the column of Line 9. This means that Line 8 (and Line 5) can have maximum contribution to Line 9 flow equal to 0.2 (this is the flow in Line 9). Similarly, Line 1, Line 6 and Line 4 contribute only to the flow in Line 5.

Table 4.2. Image domain of different branches

	Line								
Line domain	1	2	3	4	5	6	7	8	9
1	0	0	0	0	0.172	0	0	0	0
2	0	0	0	0.059	0	0	0	0.23	0
3	0.489	0	0	0	0	0.489	0	0	0
4	0	0	0	0	0.172	0	0	0	0
5	0	0	0	0	0	0	0	0	0.2
6	0	0	0	0	0.172	0	0	0	0
7	0	0	0	0.059	0	0	0	0.23	0
8	0	0	0	0	0	0	0	0	0.2
9	0	0	0	0	0	0	0	0	0
Load domain									
L2	0	0	0	0	0	0	0	0	0
L3	0.85	0	0	0.85	0	0.85	0	0	0
L4	0	0.4	0	0	0	0	0.4	0	0
L5	0	0	0	0	0.2	0	0	0.2	0
L6	0	0	0	0	0	0	0	0	0.2

The procedure for line domain calculation is explained below with reference to the simple transmission system shown in Figure 4.4.

4.2.2.2 Line dependence on domain

When line domains are determined, the next step is to calculate the percentage of power flowing in a given line that can be attributed to the flow in each line in its domain. The following algorithm accomplishes this function.

Let, L be the line whose share from the domain line K is under consideration;

Line L is connected between buses i and j and power is flowing from Bus i to j;

Line K is connected between buses i and k

Calculate,

The flow out of the bus i $\qquad F_i^{out} = \sum_{m \subset N} |P_{im}| + P_{LDi} \qquad$ (1)

The flow into bus i minus flow in line K $\qquad F_i^{in} = \sum_{q \subset N} |P_{qi}| + P_{Gi} - |P_{ik}| \qquad$ (2)

Contribution of line K to the flow in line L $\qquad C_L(K) = \frac{|Pij|}{Pik}\left(1 - \frac{F_i^{in}}{F_i^{out}}\right) \qquad$ (3)

where,

P_{im} is the power flow from bus i to m

$m \subset N$ is the set of buses connected to bus i and flow is from bus i to m

$q \subset N$ is the set of buses connected to bus i and flow is from bus q to i

P_{LDi} is the load connected to bus i

P_{Gi} is the generation at bus i

$C_L(K)$ is the percent contribution of line K towards the flow of line L

A simpler, but equivalent form of equation (3) is also available (see equation (A1) in Appendix A). The proof of this algorithm can also be found in Appendix A.

For the example system, the contribution of the flow in line 1 towards the flow of line 5 is computed as follows:

The flow out of bus 3

$$F_3^{out} = \sum_{m \subset N} |P_{im}| + P_{LDi} = P_{35} + P_{LD3} = 0.172 + 0.85 = 1.022$$

The flow into bus 3

$$F_3^{in} = \sum_{q \subset N} |P_{qi}| + P_{Gi} - |P_{ik}| = |P_{13}| + |P_{13}| + |P_{43}| - |P_{13}| = 0.481 + 0.481 + 0.060 - 0.481 = 0.541$$

Contribution of line *1* to the flow in line *5*

$$C_5(1) = \frac{P_{ij}}{|P_{ik}|}\left|\left(1 - \frac{F_i^{in}}{F_i^{out}}\right)\right| = \frac{P_{35}}{|P_{13}|}\left|\left(1 - \frac{F_3^{in}}{F_3^{out}}\right)\right| = \frac{0.172}{0.481}\left|\left(1 - \frac{0.541}{1.022}\right)\right| = 0.1682$$

Using the above procedure, the contribution factors of all lines for the sample system are calculated and presented in Table 4.3.

For example, 50% or (0.5 p.u.) of power flow in Line 8 is contributing to power flow in Line 9, while the rest supplies load L5. The flow in Line 1 (similarly to Line 6 and Line 4) supplies Line 5 in 16.86% (or 0.1686 in p.u.), while the rest of power flow in these lines supplies load L3 connected to Bus 3. This load equals to 0.85 p.u. and it is relatively large in comparison with the flow in Line 5 (0.172 in p.u.). Therefore, the majority of power flows in Lines 1, 6 and 4 goes to supply load L3. The flow in line 1 used to supply load L3 is calculated as 1-0.1686=0.8314 in p.u.

Table 4.3. Line dependence on domain

	Line								
Line domain	1	2	3	4	5	6	7	8	9
1	0	0	0	0	0.1682	0	0	0	0
2	0	0	0	0.0856	0	0	0	0.3338	0
3	0.5	0	0	0	0	0.5	0	0	0
4	0	0	0	0	0.1682	0	0	0	0
5	0	0	0	0	0	0	0	0	0.5
6	0	0	0	0	0.1682	0	0	0	0
7	0	0	0	0.0856	0	0	0	0.3338	0
8	0	0	0	0	0	0	0	0	0.5
9	0	0	0	0	0	0	0	0	0

4.2.2.3 Contribution of loads to line flow

After the image domains of the branches are determined, the next step of the algorithm is to find the contribution of the loads for those branches for which only the load in its domain determines the flow. The algorithm for this step is as follows:

```
Do for each line K
    If line K is not in the domain in any other line and contains a load Bus_i in its domain then
            contribution to Line K from load Bus_i is 100 percent
    endif
end Do
```

For the sample test system, only line 9 has all zeroes in its row (see Table 4.3) and a load bus (load L6) in its domain (see Table 4.2). Hence, the contribution from load L6 to the flow for this branch is 100%.

Next, contributions of loads to other line flows are determined using the proportionality assumption. The procedure is straightforward once the line domain contribution table is created (in our example, Table 4.3). From this table we can determine the contribution each line makes to supply the load in its domain. This contribution is obtained by subtracting all contributions this line makes to other line flows from one per unit (or form its flow if the flows are given in MW).

For example, load L3 is in the domain of line 1. From Table 4.3 we see that line 1 contributes 0.1686 to the flow in line 5, hence, the contribution to the load L3 is equal to 1 – 0.1682 = 0.8318.

To determine the contribution of load *LDk* to the flow in line *L* that does not have load *LDk* in its domain we proceed in stages. For example, to compute the contribution of load L5 to the flow in line 1, we first compute the contribution of L5 to the flow in line 5. This contribution is equal to 1 – 0.5 = 0.5 (from Table 4.3). Next, we multiply this value by the contribution of line 1 to the flow in line 5 (equal to 0.1682 – from Table 4.3) and we obtain:

$C_1(L5) = 0.5 \cdot 0.1682 = 0.0841$

The procedure can be formalized as follows. Let load *LDk* be connected to bus *i* and we want to find a contribution of *LDk* to the flow in line *L*. Let us assume that load *LDk* is not in the domain of line *L*. Using consecutive searches of the domains, we establish paths 1, 2, ...,*p*, that lead from load *LDk* to line *L*. Let lines $L_{n_1}, L_{n_2}, \ldots, L_{n_n}$ belong to a path *n* with numbering starting from bus *i* towards line *L*. The required contribution is obtained from the following expression.

$$C_L(LDk)=\sum_{n=1}^{p}\left[\prod_{k=1}^{n-1} C_{L_{n_k}}(L_{n_{k+1}})\sum_{K\subset NL}\left(1-C_{L_m}(K)\right)\right] \quad (4)$$

where

$K \subset NL$ is a set of lines that have line L_m in their domains.

$C_{L_{n_k}}(L_{n_{k+1}})$ is a contribution to the flow in line L_{n_k} by line $L_{n_{k+1}}$

A proof of this procedure is given in Appendix A.

To illustrate this algorithm, consider the contribution of load *L5* to the flow in line 3. There are two paths that lead from load *L5* to line 3; namely: *path 1* = (5, 1), and *path 2* = (5, 6). Line 5 is in the domain of line 9 only. Applying equation (4), we have

$$C_3(5)=\sum_{n=1}^{p}\sum_{K\subset NL}\left(1-C_{L_m}(K)\right)\left[\prod_{k=1}^{n-1} C_{L_{n_k}}(L_{n_{k+1}})\right]=\left[C_5(1)\cdot C_1(3)+C_5(6)\cdot C_6(3)\right]\cdot\left(1-C_9(5)\right)$$

$$=\left(0.1682\cdot 0.5+0.1682\cdot 0.5\right)\cdot(1-0.5)=0.0841$$

The results of the calculation for all lines and all delivery points are shown in Table 4.4.

Table 4.4. USTA table for the sample system

	Delivery Point					
Line	1	2	3	4	5	6
1	0	0	0.8317	0	0.0841	0.0841
2	0	0	0.0712	0.5805	0.1741	0.1669
3	0	0	0.8317	0	0.0841	0.0841
4	0	0	0.8317	0	0.0841	0.0841
5	0	0	0	0	0.5	0.5
6	0	0	0.8317	0	0.0841	0.0841
7	0	0	0.0712	0.5805	0.1741	0.1741
8	0	0	0	0	0.5	0.5
9	0	0	0	0	0.0	1.0

The determination of load contributions in MW can be obtained by multiplying the matrix presented in Table 4.4 by load values in MW.

4.2.3 Generator contribution to line flow

The algorithm to compute contributions of generators to line flows is illustrated using the same test system shown in Figure 4.4 and the load flow results presented in the Table 4.1.

4.2.3.1 Determination of image domain

The complete algorithm for the determination of image domain is as follows:

```
Do for each bus i
 find the lines and number of lines connected to bus i
      end Do
      Do for each line L
        if power flow is from Bus_i to Bus_j then
             Do for each line K connected to Bus_i
                    if the flow is towards Bus_i for line K then
                           Line K is under line domain for line L
                    endif
             end Do
             If Bus_i is a PV bus then Generator Bus_i is under line domain for line L
      else
             Do for each line K connected to Bus_j
                    if the flow is towards Bus_j for line K then
                           Line K is under line domain for line L
                    endif
             end Do
             If Bus_j is a PV bus then Generator Bus_j is under line domain for line L
        endif
      end Do
```

An application of this algorithm gives the results shown in Table 4.5. For a given row *L* and column *K*, the number represents the maximum flow in line *K* that could contribute to the flow in line *L*. This value is equal to the flow in line *K* taken from the load flow table. This table also defines the generator that belongs to the image domain of *L*. The value represents the maximum flow in *L* which can be attributed to that generator and corresponds to its generation in per unit.

The actual attribution is computed later and this table is used only to identify line domains and check the upper values of the contributions.

For example, the flow in Line 1 can be attributed to the flow in Line 3 and the output of generator G1. According to table 4.5, Line 3 can have a maximum contribution to Line 1 flow equal to 0.284 and generator G1 can have a maximum contribution to Line 1 flow equal to 0.694.

Table 4.5. Image domain of different branches

	Line domain										
	Lines									Generators	
Line	1	2	3	4	5	6	7	8	9	G1	G2
1	0	0	0.284	0	0	0	0	0	0	0.701	0
2	0	0	0	0	0	0	0	0	0	0	1.2
3	0	0	0	0	0	0	0	0	0	0	1.2
4	0	0.358	0	0	0	0	0.358	0	0	0	0
5	0.489	0	0	0.060	0	0.489	0	0	0	0	0
6	0	0	0.284	0	0	0	0	0	0	0.701	0
7	0	0	0	0	0	0	0	0	0	0	1.2
8	0	0.358	0	0	0	0	0.358	0	0	0	0
9	0	0	0	0	0.172	0	0	0.230	0	0	0

4.2.3.2 Line dependence on domain

When line domains are determined and generators are assigned to the domain, the next step is to calculate for a given line the contributions to its flow as the percentage of power flowing in each line of its domain. The following algorithm accomplishes this function.

Let, L be the line whose share from the domain line K is under consideration;

Line L is connected between buses i and j and power is flowing from Bus i to j;

Line K is connected between buses i and k

Calculate,

The flow out of the bus i minus flow in line L
$$F_i^{out} = \sum_{m \subset N} |P_{im}| + P_{LDi} - P_{ij} \qquad (5)$$

The flow into bus i
$$F_i^{in} = \sum_{q \subset N} |P_{qi}| + P_{Gi} \qquad (6)$$

Contribution of line K to the flow in line L
$$C_L(K) = \frac{P_{ik}}{|P_{ij}|}\left|\left(1 - \frac{F_i^{out}}{F_i^{in}}\right)\right| \qquad (7)$$

where,

P_{im} is the power flow from bus i to m

$m \subset N$ is the set of buses connected to bus i and flow is from bus i to m

$q \subset N$	is the set of buses connected to bus i and flow is from bus q to i
P_{LDi}	is the load connected to bus i
P_{Gi}	is the generation at bus i
$C_L(K)$	is the contribution of line K towards the flow of line L.

For the example system, the contribution of the flow in line 2 towards the flow of line 4 is computed as follows:

The flow out of bus *4*

$$F_4^{out} = \sum_{m \subset N} |P_{im}| + P_{LDi} = P_{43} + P_{45} + P_{LD4} - P_{43} = 0.060 + 0.23 + 0.400 - 0.060 = 0.630$$

The flow into bus *4*

$$F_4^{in} = \sum_{q \subset N} |P_{qi}| + P_{Gi} = |P_{24}| + |P_{24}| + |P_{G4}| = 0.345 + 0.345 + 0.000 = 0.690$$

Contribution of line *2* to the flow in line *4*

$$C_4(2) = \frac{P_{ik}}{|P_{ij}|}\left|\left(1 - \frac{F_i^{in}}{F_i^{out}}\right)\right| = \frac{P_{42}}{|P_{43}|}\left|\left(1 - \frac{F_4^{out}}{F_4^{in}}\right)\right| = \frac{0.345}{0.060}\left|\left(1 - \frac{0.690}{0.630}\right)\right| = 0.500$$

Using the above equations and procedure, the dependence of all the lines for the example case are calculated and presented in Table 4.6.

Table 4.6. Dependence of lines on their line domain

Line/	Dependence on line								
Line	1	2	3	4	5	6	7	8	9
1	0.00	0.00	0.2835	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.50	0.00	0.00	0.00	0.00	0.50	0.00	0.00
5	0.471	0.00	0.00	0.0579	0.00	0.471	0.00	0.00	0.00
6	0.00	0.00	0.2835	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.50	0.00	0.00	0.00	0.00	0.50	0.00	0.00
9	0.00	0.00	0.00	0.00	0.4271	0.00	0.00	0.5729	0.00

4.2.3.3 Contribution of generators to line flow

After the image domains of the branches are determined, the next step of the algorithm is to find the contribution of the generators to those branches for which only the generator in its domain determines the flow. The algorithm for this step is as follows:

```
Do for each line K
        If line domain of line K does not contain lines AND contains generator Bus_i then
                contribution to Line K from generator Bus_i is 100 percent
        endif
end Do
```

For the example test system, as can be seen from Table 4.5, generator 2 is in the image domain of lines 2, 3 and 7 and hence the contribution to the line flows for these branches are 100% from generator 2.

To determine the contribution of generator *Gk* to the flow in line *L* that does not have generator *Gk* in its domain we proceed in stages. For example, to compute the contribution of generator G2 to the flow in line 1, we multiply the dependence of flow in line 1 on flow in line 3 by the dependence of flow in line 3 on generator 2, and we obtain:

$C_1(G2) = 0.2835 \cdot 1 = 0.2835$

The procedure can be generalized as follows. Let generator *Gk* be connected to bus *i* and we want to find a dependence of flow in line *L* on generator *Gk*. Let us assume that generator *Gk* is not in the domain of line *L*. Using consecutive searches of the domains, we establish paths 1, 2, ...,*p*, that lead from generator *Gk* to line *L*. Let lines $L_{n_1}, L_{n_2}, ..., L_{n_n}$ belong to a path *n* with numbering starting from bus *i* towards line *L*. The required contribution is obtained from the following expression.

$$C_L(Gk) = \sum_{n=1}^{p}\left[\prod_{k=2}^{n} C_{L_{n_{k+1}}}(L_{n_k}) * \left(C_{L_{n_1}}(Gk)\right)\right] \qquad (8)$$

where

k from 2 to n, is a set of lines that do not have *Gk* in their domains,

l is the line which has *Gk* in its domain,

$C_{L_{n_{k+1}}}(L_{n_k})$ is a contribution of the line L_{n_k} to the flow in line $L_{n_{k+1}}$

To illustrate this algorithm, consider the dependence of the flow in line 5 on the generator 2. There are four paths that lead from G2 *to* line 5 namely: *path 1* = (3, 1), *path 2* = (3, 6), path 3 = (2, 4) and path 4 = (7, 4). Applying equation (8), we have

$$C_5(G2) = \sum_{n=1}^{p}\left(C_{L_{n_n}}(Gk)\right) * \left[\prod_{k=1}^{n-1} C_{L_{n_k}}(L_{n_{k+1}})\right] =$$

$$= \left[C_5(1)\cdot C_1(3)\cdot C_3(G2) + C_5(6)\cdot C_6(3)\cdot C_3(G2) + C_5(4)\cdot C_4(2)\cdot C_2(G2) + C_5(4)\cdot C_4(7)\cdot C_7(G2)\right]$$

$$= \left(0.471\cdot 0.2835\cdot 1 + 0.471\cdot 0.2835\cdot 1 + 0.0579\cdot 0.5\cdot 1 + 0.0579\cdot 0.5\cdot 1\right) = 0.3249$$

From the dependence of lines on their line domain, the contribution from the generators can be found. It should be noted that this step has to be repeated until the sum of the contribution becomes 100%. The complete algorithm for this step is shown below:

```
Do for each line L
        Find the sum of contribution to L from each generator bus
        If this sum becomes within acceptable tolerance then
        skip this line and go for the next line
    else
        find the contribution to L from the contribution of generator using the
        domain of L
    endif
enddo
Repeat the above do loop until the sum of contribution for all lines from the generators meet
the tolerance level
```

The results are presented in Table 4.7.

Table 4.7. Dependence of line on generators

		Dependence on generator	
Iteration	Line	1	2
2	1	0.7165	0.2835
	2	0.00	1.00
	3	0.00	1.00
	4	0.00	1.00
	5	0.675	0.3250
	6	0.7165	0.2835
	7	0.00	1.00
	8	0.00	1.00
	9	0.2883	0.7117

4.3 The VPX Algorithm

The VPX (Victoria Power Exchange, [1]) algorithm was developed for the Australian system to determine transmission asset sharing by various customers.

The algorithm consists of the following steps:

1. **Attribute network costs to network elements**
2. **Determine the fault contribution matrix to allocate generation to loads**
3. **Determine constrained allocation of actual generation to loads**
4. **Calculate line flow contributions of each load**
5. **Calculate relative utilization of each network element by each load**
6. **Determine the share of each network element required by each load**
7. **Allocate network costs to each load**

This section addresses steps 2 to 6.

The VPX method is illustrated using a small sample system shown in Figure 4.5. The data is in Tables 4.8 and 4.9.

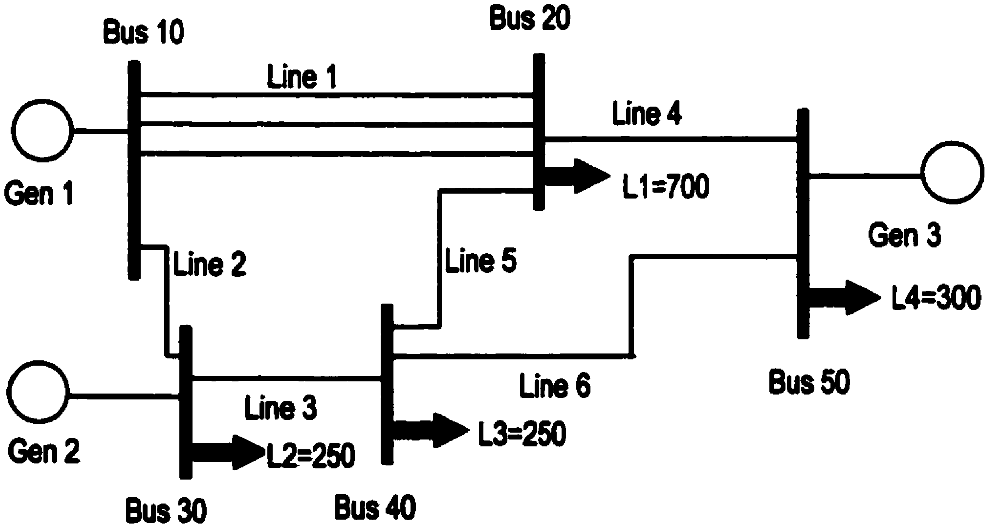

Figure 4.5. The sample test system

Table 4.8. Load Flow Results

	Voltage				Power flow from	
Bus/Line	Magnitude in p.u.	Angle in radians	Bus *i*	Bus *j*	bus *i* to *j* (p.u.)	Bus *j* to *i* (p.u.)
10/1	1.04000	0.00000	10	20	763	−736
20/2	1.05000	−0.14311	10	30	276	−271
30/3	1.03059	−0.07330	30	40	321	-316
40/4	1.02879	−0.08726	20	50	53.1	−52.1
50/5			20	40	−17.3	17.4
6	–	–	40	50	48.6	−47.9

Table 4.9. Generator Information

Generator	Output (MW)
1	1039.3
2	300.0
3	200.0

4.3.1 Fault Contribution Matrix

The calculation of the use of the network by each load requires the source of generation for each load to be identified. This requires an assumption to be made since in electrical networks it is not possible to identify the source of generation which supplies a particular load. The power generated by generators are fed into a "pool" from which loads draw supply, with flows based on physical laws. It is not possible for the output of a generator to be sent to a particular load, and it is not possible to determine a unique allocation.

The VPX method uses the electrical distance as measured by the impedance between each load and generator as the measure of the extent to which each generator supplies each load. The greater the electrical distance between a generator and load the less power that generator is assumed to supply that load. Therefore, the allocation of generation to load is made in inversely proportion to the electrical distance (impedance) between them.

The VPX method uses standard classical fault level analysis to determine the impedance between generators and loads. The generator to load allocation is carried out according to relative fault contributions by each generator to a 3 phase fault at each load point.

A single fault level study is carried out for the network under conditions of maximum system demand and with all generators in service, with their output uniformly scaled to meet the loading requirement. This analysis differs from classical fault analysis in that the generator impedance (X_d' or X_d'') is not used, a value of zero is set. This is valid since the results of the fault analysis are applied to the generation "sent out" at each bus. Generator impedance is irrelevant, the network components being the only indicator of electrical distance.

This single fault level study is used to determine the base allocation matrix. For simplicity this analysis is not repeated for each operating scenario, but is used to construct a generation to load allocation which recognises the constraints on generator output and loading levels for each of the operating conditions to be studied.

For this example the transformer impedance used for the calculation of fault contributions is 4%, 3.64% and 8% respectively for generators 1, 2 and 3. The base fault level contribution matrix for this example is then:

$$[FL] = \begin{bmatrix} 0.4225 & 0.3603 & 0.2173 \\ 0.3059 & 0.5611 & 0.1330 \\ 0.3345 & 0.4619 & 0.2036 \\ 0.2804 & 0.29.27 & 0.4270 \end{bmatrix}$$

This matrix shows the contribution from generators on busbars 10, 30 and 50 (columns in the matrix) to loads at busbars 20, 30, 40 and 50 (rows in the matrix). It shows for example that for load at bus 30, 30.6% is supplied from generator on bus 10, 56.1% from the generator on bus 30 and 13.3% from the generator on busbar 50.

It is then necessary to establish a constrained generator to load allocation using this base matrix. This requires that actual generation and load for the particular operating condition being considered are matched in the allocation.

4.3.2 Constrained Allocation of generation to loads

This section shows in detail how the constrained generator to load allocation matrix is determined from the base fault level contribution matrix obtained in the last section as well as from the generation and loading conditions.

The first step is to determine the allocation of losses between the generators. These losses are assumed to be shared among generators on a pro-rata basis with generator output. The total system losses are calculated as the difference between generation and load as 39.2 MW for this loading condition.

This results in the following generation outputs taking into account losses in order to allow computation of the constrained generator to load allocation without the inclusion of losses:

Generator 1	1039.2*(1–39.2/1539.2) = 1012.7 MW
Generator 2	300*(1–39.2/1539.2) = 292.35 MW
Generator 3	200*(1–39.2/1539.2) = 194.90 MW

The calculation of the constrained generator to load allocation matrix from the base fault level allocation proceeds as follows:

Step 1 The base matrix is multiplied by the loading which applies to each row. This shows where generation would be directed if there were no restrictions on generator output.

In this case the first row of the fault contribution matrix is multiplied by the load at bus 20, i.e. 700MW. The result is

$$\begin{bmatrix} 295.715 & 252.203 & 152.082 \\ 76.478 & 140.270 & 33.253 \\ 83.615 & 115.478 & 50.908 \\ 84.123 & 87.795 & 128.082 \end{bmatrix}$$

The totals in generation are 539.9305 MW, 595.7455 MW and 364.324 MW respectively. Since these totals exceed the available generation for generators 2 and 3 the matrix is scaled to provide a match for the most overloaded generator. In this case the maximum output of generator 2 is 292.35 (following adjustment for losses) so that the requirement is a factor of 2.038 above its available output. Consequently the whole of the above matrix is scaled by this factor to yield the following matrix.

$$\begin{bmatrix} 145.116 & 123.764 & 74.6312 \\ 37.530 & 68.835 & 16.318 \\ 41.032 & 56.668 & 24.982 \\ 41.282 & 43.084 & 62.854 \end{bmatrix}$$

The complete output of 292.35 for generator 2 is allocated while 264.960 MW is allocated for generator 1 and 178.785 MW is allocated for generator 3. The loads allocated by this pass are 343.511 MW, 122.682, 122.682 and 147.219 MW respectively.

The allocation made in this pass is taken from the process and the residuals are allocated in the next pass.

Step 2 Pass 2 is carried out by removing the fully allocated generator from the base fault allocation matrix.

The basic fault allocation matrix is modified by inserting zero's in the column for generator 2. Each row is then scaled so that it totals 1.0000 as follows:

The column for generator 2 is zeroed.

$$\begin{bmatrix} 0.4225 & 0.0 & 0.2173 \\ 0.3059 & 0.0 & 0.1330 \\ 0.3345 & 0.0 & 0.2036 \\ 0.2804 & 0.0 & 0.4269 \end{bmatrix}$$

The rows are scaled so that each one totals 1.0000

$$\begin{bmatrix} 0.6603 & 0.0 & 0.3396 \\ 0.6970 & 0.0 & 0.3030 \\ 0.6216 & 0.0 & 0.3784 \\ 0.3964 & 0.0 & 0.6036 \end{bmatrix}$$

From the first pass the remaining load to be allocated is

Load 1	*356.4892 MW*
Load 2	*127.3176 MW*
Load 3	*127.3176 MW*
Load 4	*152.7811 MW*

Generation remaining to be allocated is:

Generator 1 747.7401 MW

Generator 3 16.1154 MW

The allocation of the above residuals proceeds as before with each row of the modified fault allocation matrix multiplied by the residual loading to give the following matrix.

$$\begin{bmatrix} 235.4174 & 0.0 & 121.0718 \\ 88.7354 & 0.0 & 38.5822 \\ 79.1367 & 0.0 & 48.1810 \\ 60.5660 & 0.0 & 92.2151 \end{bmatrix}$$

This results in a total generation requirement of 463.8554 MW from generator 1 and 300.0501 MW from generator 3. Since generator 3 has only 16.1154 MW remaining to be allocated the matrix is scaled by 16.1154/300.0501 or 0.0537 to fully allocate the remaining output from generator 3. This results in the following:

$$\begin{bmatrix} 12.6440 & 0.0 & 6.50270 \\ 4.7659 & 0.0 & 2.0722 \\ 4.2504 & 0.0 & 2.5878 \\ 3.2529 & 0.0 & 4.9528 \end{bmatrix}$$

This provides a further allocation of generation to load and now the output of generator 3 is fully allocated; 178.78 MW in the first pass and 16.12 MW in the second. An additional 24.9132 MW of generator 1 output has been allocated while additional loads of 19.1467 MW, 6.8381 MW, 6.8381 MW and 8.2057 MW have been allocated for Loads 1 to 4 respectively. As before the load and generation remaining to be allocated can be calculated by subtracting those allocated in this step from those remaining to be allocated at the start of the step, i.e.:

Load 1	356.4892 - 19.14669 = 337.3425 MW
Load 2	127.3176 - 6.83810 = 120.4795 MW
Load 3	127.3176 - 6.83810 = 120.4795 MW
Load 4	152.7811 - 8.20572 = 144.5754 MW

Step 3 Allocation of Remaining Generation

The only remaining generation to be allocated is 722.8269 MW which by definition must match the total load remaining to be allocated. Consequently the remaining allocation in matrix form is simply:

$$\begin{bmatrix} 337.3425 & 0.0 & 0.0 \\ 120.4795 & 0.0 & 0.0 \\ 120.4795 & 0.0 & 0.0 \\ 144.5754 & 0.0 & 0.0 \end{bmatrix}$$

Step 4 Total Generation to Load Allocation

The total generation to load allocation is now calculated by adding together the allocations made at each of the above passes. This can be done in matrix form to provide the following result.

$$\begin{bmatrix} 495.1027 & 123.7635 & 81.1338 \\ 162.7751 & 68.8347 & 18.3902 \\ 165.7622 & 56.6682 & 27.5696 \\ 189.1100 & 43.0836 & 67.8064 \end{bmatrix}$$

A check reveals that the total allocated load and generation achieved by adding rows and columns respectively matches the requirements excluding the losses.

This generation to load allocation matrix is used for the allocation of costs for the particular operating scenario (as shown in this chapter). The calculation of a new constrained generation to load allocation matrix is necessary for each operating condition being considered in the cost allocation.

4.3.3 Line Flow contributions of each load

Sensitivity Matrix

The Sensitivity Matrix is determined for the system from loadflow analysis, and can be formed from the Jacobian. Note that in the formation of the sensitivity matrix the line to and from bus is defined so that the standing line flow is in the positive direction.

$$[A] = \begin{bmatrix} 0.000 & 0.810 & 0.295 & 0.505 & 0.695 \\ 0.000 & 0.213 & 0.708 & 0.524 & 0.350 \\ 0.000 & 0.200 & -0.284 & 0.492 & 0.329 \\ 0.000 & -0.039 & 0.056 & 0.096 & 0.463 \\ 0.000 & 0.054 & -0.077 & -0.132 & -0.024 \\ 0.000 & 0.047 & -0.067 & -0.115 & 0.363 \end{bmatrix}$$

The quantities are ordered as lines 1 to 6 as the rows with busbars 10 to 50 as the columns with bus 10 as the swing. The physical interpretation of the matrix is that each element is the change in flow that would occur for the particular network element for an increment of additional load or generation at each point supplied from the swing bus. For example A(3,3) = A(line 30-40, bus 30) = -0.284 which is the change in flow that would occur on line #3 if a small increment of load (say 1 MW) was supplied from generator 1 (on bus 10) to the load on bus 30 (i.e. distributor 4). The negative sign indicates that the change in flow is in the opposite direction to the standing flow on the line.
This calculation is carried out for real power only.

4.3.4 Relative utilisation by each load of each network element

The sensitivity matrix shows the increment of loading that will occur on each line as a result of a load change and a corresponding generation change. The load allocation or participation matrix can be formed for each load point by multiplying the sensitivity matrix by the constrained generation to load allocation matrix, where this matrix includes the load change for the specified busbar and the generation change as determined from the generation to load allocation.
The physical interpretation of this procedure is that a load increment is made at the specified load bus. The output of each generator is incremented in accordance with the generator to load allocation determined above to supply the load increase. The flow on each line is calculated to determine the increment of flow which results from this additional loading.

This is inherently weighted by the total load to form a flow component attributed to each line to supply the particular load.

The System Loading Matrix

The information required is the sensitivity matrix, and a matrix which includes the loading to be imposed on the network and its generation source. This latter matrix is formed from the generation to load allocation matrix and the system load information.

It is important to recognise that the generation to load allocation determined above specifically excluded losses from the allocation. The physical interpretation of the generation to load allocation is that it provides the change in generation for each generator required to meet the load change referred to the load point. In order to determine the change in line flows it is necessary to determine the actual generation change at the generator busbar, which is necessary to match the specified generation component at the load bus.

This will be different to the extent that the additional flow will result in additional network losses. The generator will be required to provide sufficient additional output to meet the specified load increase plus a small component to cover the additional network losses[14].

The system equation allows the loading increase at a load bus to be referred to any generator bus. The system equation is:

$$P_{10} + 1.0750P_{20} + 1.0405P_{30} + 1.0725P_{40} + 1.0939P_{50} = 0.0$$

Taking supply to Load 3 on Bus 40 as an example the constrained generation to load allocation matrix indicates that of the 250 MW of load, 27.57 MW is attributed to Generator 3 at Bus 50. The system equation can be expressed as:

$$1.0725P_{40} = -1.0939P_{50}$$

$$P_{50} = \frac{-1.0725P_{40}}{1.0939}$$

Consequently the Generator 3 output is increased by

$$\text{Generator3} = P_{50} = \frac{-1.0725 \times -27.57}{1.0939} = 27.0303$$

and this would provide the appropriate term for inclusion in the load sensitivity matrix.

[14]There may be a decrease in network losses in which case the generator would be required to provide less than the specified load increase, however all the concepts described here are the same in this case.

This modified matrix is as follows:

$$\begin{bmatrix} 532.2354 & 127.8671 & 79.7320 \\ 169.3675 & 68.8347 & 17.4925 \\ 177.7799 & 58.4110 & 27.0302 \\ 206.8674 & 45.2947 & 67.8064 \end{bmatrix}$$

The flow on each network element can now be determined for each load by multiplying the sensitivity matrix (which has dimension no. of network elements by the no. of busbars) by the system loading matrix. Consequently the full system loading matrix is a square matrix dimensioned to the number of busbars and is created by filling out the above matrix to include busbars where there is no load and generation and including the loads to be included in the analysis at the relevant busbar.

$$[L]=\begin{bmatrix} -5.3224 & -1.6937 & -1.7778 & -2.0687 \\ 7.0000 & 0.0000 & 0.0000 & 0.0000 \\ -1.2787 & 2.5000-0.6883 & -0.5841 & -0.4529 \\ 0.0000 & 0.0000 & 2.5000 & 0.0000 \\ -0.7973 & -0.1749 & -0.2703 & 3.0000-0.6781 \end{bmatrix}$$

The component of flow on each network element resulting from the loading at each bus can be determined by multiplying the sensitivity matrix [A] by the above system loading matrix [L] to form the participation matrix [P].

Then the participation matrix is formed as:

$$[P]=[A][L]$$

where [A] was defined above.

$$[P]=\begin{bmatrix} 4.737 & 0.413 & 0.903 & 1.479 \\ 0.308 & 1.222 & 0.801 & 0.492 \\ 1.502 & -0.572 & 1.306 & 0.891 \\ -0.717 & 0.020 & 0.082 & 1.049 \\ 0.498 & -0.135 & -0.278 & -0.022 \\ 0.126 & -0.185 & -0.346 & 0.873 \end{bmatrix}$$

The last step in the formation of the participation matrix for the particular operating condition is to set any of the line flow components which are in the opposite direction to the standing flow on the network element to zero. This ensures that only the flow components that increase the flow on the network element are included in the sharing of costs. This is justified since flow components which act to off-load network elements will not contribute to the need for their augmentation.[15]

$$[P]=\begin{bmatrix} 4.737 & 0.413 & 0.903 & 1.479 \\ 0.308 & 1.222 & 0.801 & 0.492 \\ 1.502 & 0.000 & 1.306 & 0.891 \\ 0.000 & 0.020 & 0.082 & 1.049 \\ 0.498 & 0.000 & 0.000 & 0.000 \\ 0.126 & 0.000 & 0.000 & 0.873 \end{bmatrix}$$

The cost allocation for the shared EHV network requires that a number of scenarios be considered to ensure that all critical operating modes of the system are considered. This results in a different participation matrix for each operating condition. These are accumulated over the operating conditions considered, for example the flow components are summed for all operating conditions[16].

The final participation matrix obtained after accumulation of all operating conditions is then normalised so that the total for each line is unity therefore ensuring allocation of all the costs (i.e. each row of the normalised matrix sums to 1.0000). Considering only the single operating condition for this example the normalised participation matrix may be written.

---

[15]An alternative is that a credit could be applied for flow in the opposite direction to the line flow. While this would seem justifiable it can result in inequitable allocation of fixed costs for lines which have close to zero flow, or for elements in which bi-directional flows are common, particularly the interconnectors.

[16]The accumulation takes place after the flow components counter to the standing flow for the particular operating condition have been removed. Some network elements may be subject to flows in either direction depending on the particular operating condition. In these cases the positive flow components retained for one operating condition may be in the opposite direction in the physical sense to those retained from another. However this physical direction is immaterial in the analysis with positive values (based on standing flow) being accumulated over all operating conditions.

$$[P] = \begin{bmatrix} 0.629 & 0.055 & 0.120 & 0.196 \\ 0.109 & 0.433 & 0.284 & 0.174 \\ 0.406 & 0.000 & 0.353 & 0.241 \\ 0.000 & 0.018 & 0.071 & 0.911 \\ 1.000 & 0.000 & 0.000 & 0.000 \\ 0.126 & 0.000 & 0.000 & 0.874 \end{bmatrix}$$

4.4 The UMIST Approach

The algorithm presented in [3], referred to as the *UMIST algorithm* in this section, also uses the proportionality assumption but differs in one significant point from the algorithm presented here. In order to explain the difference, we will briefly review the UMIST algorithm.

In the UMIST approach, all buses are grouped into disjoint sets called *commons*. A common is a set of contiguous buses supplied by the same generators. Unconnected sets of buses supplied by the same generators are treated as separate commons. A bus, therefore, belongs to one and only one common.

For example, the system in Figure 4.4 is composed of two commons. Common one is composed of buses 2 and 4 that are supplied by generator G_2 whereas common 2 includes buses 1, 3, 5 and 6 that are supplied by both generators.

After the buses are grouped into commons, the links are identified between the commons. In our example, there is one link between the two commons. This link is composed of lines 3, 4 and 8. The flows in these lines are taken at the receiving end and are, therefore, equal to 0.277, 0.06 and 0.229 p.u., respectively.

Now the contribution of each generator to the load and the flow into a common can be established as a proportion of the generator output flowing in the links. Thus, the contribution of generator G_2 to the load in common 2 is equal to $(0.277+0.06+0.229)/1.2=0.472$. The load in common 2 is composed of three components *L3*, *L5* and *L6* and is equal to 1.25 p.u. Therefore, G_2 supplies 0.59 p.u. of the load in these buses.

A crucial assumption in the UMIST method states that the proportionality principle applies not only to the common taken as a whole, but also to each bus load and to each branch flow taken independently within the common.

Taking again example in Figure 4.4 , generator G_2 supplies 47.2% of the load at bus 3 and the same proportion of the load at buses 5 and 6. Therefore, G_2 supplies $0.472 \cdot 0.85 = 0.40$ p.u. at bus 3 and 0.094 p.u. of the load at buses 5 and 6.

On the other hand, in the USTA approach generator G_2 would supply 0.24 p.u. of load at bus 3 and 0.14 p.u. of load at buses 5 and 6. To explain this difference let us consider the load at bus 3. Generator G_2 would contribute only the part of its output flowing in lines 3 and 4 to the supply of load 3. These flows constitute $(0.06+0.277)/1.2 = 0.281$, or 28.1% of its output. Therefore, the contribution of G_2 to load *L3* is equal to $0.281 \cdot 0.85 = 0.239$ p.u. Similarly, generator G_2 contributes 47.2% of its output to supply loads 5 and 6; that is, it supplies 0.094 p.u. of the load at these buses.

The difference in both approaches is now apparent. In the UMIST algorithm, all three lines out of common 1; that is, lines 3, 4 and 8 are deemed to supply *L3*. Whereas in the USTA algorithm, only lines 3 and 4 from common 1 would supply this load. Considering the particular load flow scenario studied in this example, it seems that the USTA results are more reasonable.

5 ALLOCATION OF COSTS TO NETWORK COST CATEGORIES

5.1 Introduction

The general process to allocate total cost to network assets was described in Chapter 3. This chapter focuses on details of the computations and illustrates them using the sample test system shown in Figure 5.1 with the cost data taken from [1]. Finally, a comparison of the two allocation methods, Image Domain algorithm and VPX method, described in Chapter 4 is made.

5.2 Determination of Individual Asset Costs

Initially it is necessary to distribute assets in cost categories to determine the costs which apply in each of the categories, and to determine the annual costs for individual assets in the transmission network.

In order to illustrate the concepts Bus 10 and Bus 20 of the sample test system in Figure 4.5 is considered in more detail. The single line diagram for each station is shown in Figure 5.1 below.

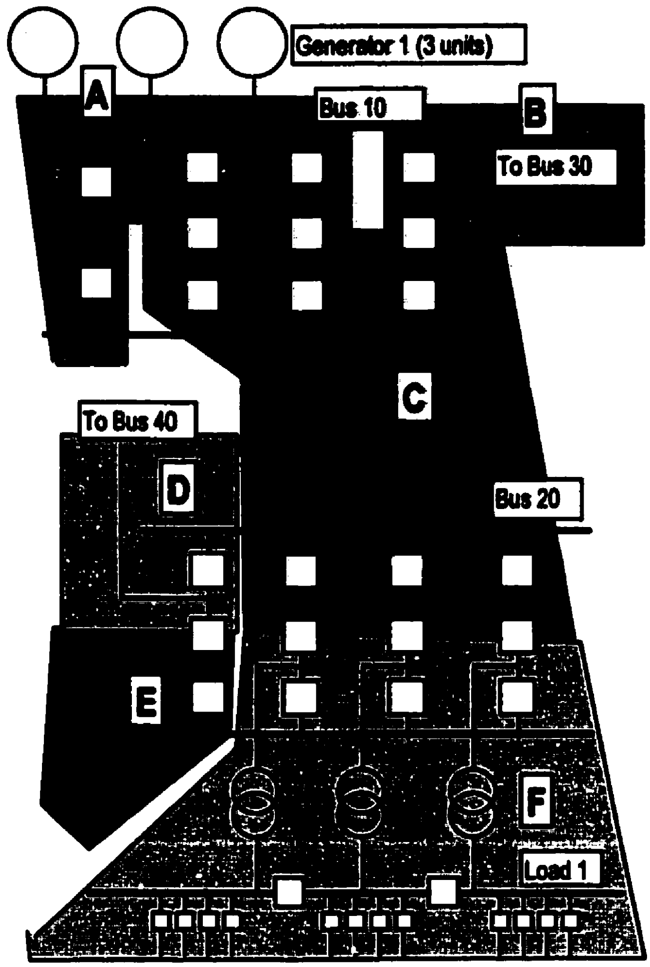

Figure 5.1. Categorization of Network Assets

This figure illustrates the manner in which network assets are grouped into appropriate cost categories. This diagram of two of the stations in the network fully describes the concepts for most situations.

The following describes each of the asset categories and shows how the network costs are derived in each case. The letters refer to those in the shaded sections of Figure 5.1.

A Connection Assets for Generator 1 (Entry)

The generator entry charges for Bus 10 include only the dedicated EHV circuit breakers required to connect the generator into the power station switchyard. The generator transformers are assumed to be owned by the power station owner. Entry charges are not considered further in this example since they are not part of the scope of this chapter.

B Transmission Line from Bus 10 to Bus 30

This line is part of the shared EHV network. As previously noted the allocation of the shared network costs involves determining the flow imposed on each element by users of the network and sharing the costs accordingly.

This approach means that the costs of all shared network assets have to be represented between nodes. Therefore, all relevant station costs have to be allocated to lines.

This is achieved by including those station assets involved in terminating and switching the line at each end in such a way that all station costs are covered. In this case the cost of the line from Bus 10 to Bus 30 includes one and a half circuit breakers (from the standard breaker and a half arrangement) at Bus 10 and assuming similar termination at Bus 30 would also be allocated another one and a half circuit breakers at the other end. Assuming an individual cost of $1.5 million per breaker, this provides a total switchgear cost of $4.5 million.

Transmission lines are often valued based on standard asset values. Assuming the line from Bus 10 to Bus 30 is 75 km long with a standard price of $720 000 per km, the total value of this line is:

$$\text{ReplacementValue(Bus10} - \text{Bus30)} = 75 \times 720{,}000 + 4{,}500{,}000 = \$58.5\text{million}$$

Assuming the annual cost fraction of 10%, this line would be included in the cost allocation with an annual cost of $5,850,000.

C Transmission Lines From Bus 10 to Bus 20

The assets in the shaded area C are also attributed to transmission lines. In this case there are the equivalent of 9 EHV circuit breakers with a total replacement cost of $13.500,000. Assuming the lines are each 50 km in length with a standard replacement value of $720,000 per km, the total replacement value of these assets is $121.5 million corresponding to an annual cost of $12.15 million.

D Transmission Line From Bus 20 to Bus 40

As for the above lines the replacement value used in the cost allocation for this line includes 3 EHV circuit breakers (breaker and a half arrangement at each end). The line is 100 km long so that the replacement cost is $76.5 million for an annual charge of $7.65 million.

E Common Service (Reactive Plant)

The capacitor bank is charged against common service. The total cost for the assets here is $4.0 million for the capacitor bank and $2.25 million for the one and a half circuit breakers associated with switching. This gives a total replacement cost of $6.25 million for an annual charge of $625,000.

F Exit Assets

Category F shows all the connection assets for supply to Load 1. The total assets shown here are 4½ EHV circuit breakers, 14 LV circuit breakers and 3 transformers.
No further consideration is given in this thesis.

5.3 Determination of Annual Network Costs

The total replacement values of the assets included in the optimised network can be determined by adding the individual replacement asset values as shown in Table 5.1. The total is $574.9 million.

Table 5.1. Network Element Costs[17]

Line Number	From Bus	To Bus	Replacement Cost ($'000,000)
1	Bus10	Bus20	121.5
2	Bus10	Bus30	58.5
3	Bus30	Bus40	44.8
4	Bus20	Bus50	100.0
5	Bus20	Bus40	76.5
6	Bus40	Bus50	173.6

5.4 Transmission Use of System Charges

For this example the following annual charges and costs are considered:

Locational Component of the Network Charge: $57.49 million pa;

[17]For simplicity in the example the costs of circuit breakers for line terminations are included in the network owners territory which has ownership of the line. In practice it is likely that ownership of this switchgear

Common Service Component of the Network Charge: **$10.00 million pa;**

Operating Company Network Related Costs: **$ 5.00 million pa;**

The total Locational Component of the Network Charge is to be recovered from both loads and generators. Ultimately each generator will pay for firm access to the system through Use of System charges. The revenue obtained from the sale of firm access will be subtracted from the Locational Component of the Network Charge in setting the total Locational Component of the Network Charge to be recovered from load points.

In this example it is assumed that half of the Locational Component of the Network Charge is recovered from generators leaving the other half, or $28 745 000 to be recovered from loads[18]. This is allocated on a pro-rata basis between all network elements to give the annual revenue required to be recovered from each individual element. The result of this allocation is shown in Table 5.2.

Table 5.2. Meshed network element annual costs for allocation to loads

Line Number	From Bus	To Bus	Annual Cost ($'000,000)
1	Bus10	Bus20	6.075
2	Bus10	Bus30	2.925
3	Bus30	Bus40	2.240
4	Bus20	Bus50	5.000
5	Bus20	Bus40	3.825
6	Bus40	Bus50	8.680

5.5 Share of each network element required by each load

The cost of the individual network element to be met by loads is shared on a pro-rata basis with the average flow component that each load has imposed on the element for the operating conditions considered.

would lie with ownership of the substation. This is likely to be different in which case ownership of the costs of some network elements may be split between two owners. This aspect is avoided in this example.

[18]In practice given current stage of development of the network it is extremely unlikely that generators will contribute such a high proportion using the firm access approch.

To determine the allocated network costs for each load point of the sample test using VPX method, the transpose of the participation matrix, defined in section 4.3.4. is multiplied by the cost vector as follows:

$$[Cost]=\begin{bmatrix} 0.629 & 0.109 & 0.406 & 0.000 & 1.000 & 0.126 \\ 0.055 & 0.433 & 0.000 & 0.018 & 0.000 & 0.000 \\ 0.120 & 0.284 & 0.353 & 0.071 & 0.000 & 0.000 \\ 0.196 & 0.174 & 0.241 & 0.911 & 0.000 & 0.874 \end{bmatrix}\begin{bmatrix} 6.075 \\ 2.925 \\ 2.240 \\ 5.000 \\ 3.825 \\ 8.680 \end{bmatrix}$$

When multiplied this yields the following charges:

$$\begin{bmatrix} Load_1 \\ Load_2 \\ Load_3 \\ Load_4 \end{bmatrix}=\begin{bmatrix} 9.971 \\ 1.689 \\ 2.705 \\ 14.381 \end{bmatrix}$$

Similarly, the allocated network costs using the image domain algorithm are computed as follows:

$$[Cost]=\begin{bmatrix} 0.929 & 0.041 & 0.073 & 0.000 & 0.929 & 0.000 \\ 0.000 & 0.438 & 0.000 & 0.000 & 0.000 & 0.000 \\ 0.000 & 0.434 & 0.771 & 0.000 & 0.000 & 0.000 \\ 0.070 & 0.087 & 0.155 & 1.000 & 0.070 & 1.000 \end{bmatrix}\begin{bmatrix} 6.075 \\ 2.925 \\ 2.240 \\ 5.000 \\ 3.825 \\ 8.680 \end{bmatrix}$$

Which yields the following results.

$$\begin{bmatrix} Load_1 \\ Load_2 \\ Load_3 \\ Load_4 \end{bmatrix}=\begin{bmatrix} 9.486 \\ 1.280 \\ 2.996 \\ 14.982 \end{bmatrix}$$

5.6 Comparison of Image Domain and VPX methods for evaluation of transmission use by loads and generators

The system example shown in Figure 4.5, is used to compare the two main methodologies addressed in this thesis: Image Domain Algorithm and VPX method.

5.6.1 Contribution of loads to line flows

Contributions obtained applying VPX method are those that correspond to the matrix [P] in section 4.3.4 and are presented in the following table. The contributions obtained applying image domain algorithm are also shown in this table.

Table 5.3. Contributions of loads to flow in lines

	Load							
Line	1		2		3		4	
	Image	VPX	Image	VPX	Image	VPX	Image	VPX
1	0.929	0.629	0.000	0.055	0.000	0.120	0.070	0.196
2	0.041	0.109	0.438	0.433	0.434	0.284	0.087	0.174
3	0.073	0.406	0.000	0.000	0.771	0.353	0.155	0.241
4	0.000	0.000	0.000	0.018	0.000	0.071	1.000	0.911
5	0.929	1.000	0.000	0.000	0.000	0.000	0.070	0.000
6	0.000	0.126	0.000	0.000	0.000	0.000	1.000	0.874

The differences in the results are due to the fact that the VPX method uses fault analysis to determine the impedance between generators and loads and eventually to compute contributions. This fault analysis is carried out independently for each load point which makes all generators contribute to the "fault" according to their electrical distance to that specific load, neglecting the other loads. In the Image Domain algorithm, on the other hand, only those generators contribute to the flow in a given line that have a positive flow path from the generator bus towards the line.

This situation can be explained in Figures 5.2 and 5.3 by analyzing contributions made by load 2 to the flows in various lines.

Let us consider bus 30 to which load 2 is connected. In the Image Domain algorithm only the flow in line 2 contributes to the load at this bus because the flow in line 3 (the other line connected to bus 30) is away from this bus.

In the VPX algorithm, on the other hand, not only line 2 but also lines 1 and 4 would supply the load at bus 30. This is because the electrical distance calculations recognize that there are relatively low impedance paths to bus 30 through lines 1, 5 and 3 and trough lines 1, 4, 6 and 3. However, lines 3, 5 and 6 are neglected as lines that contribute to the flow to load 2 due to its flow is negative. Therefore, for the purpose of allocating transmission costs, the load 2 is not be charged for the use of those lines because this load is decreasing their flow.

In my opinion, the VPX approach is much more difficult to justify compared with the Image Domain algorithm.

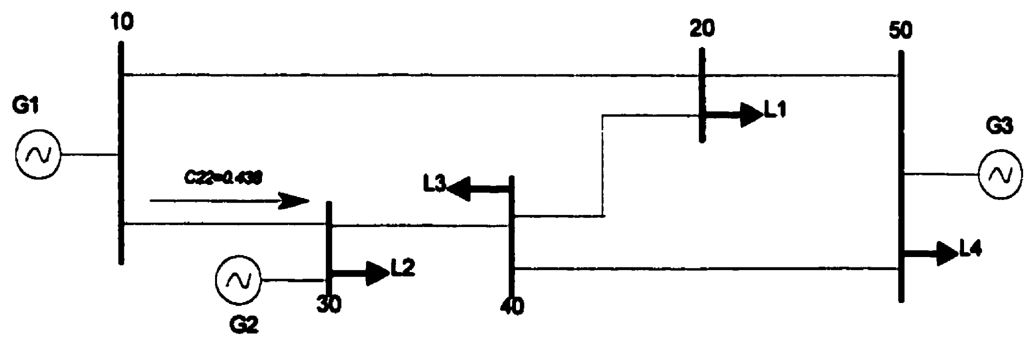

Figure 5.2. Contributions to load 2 with image domain algorithm

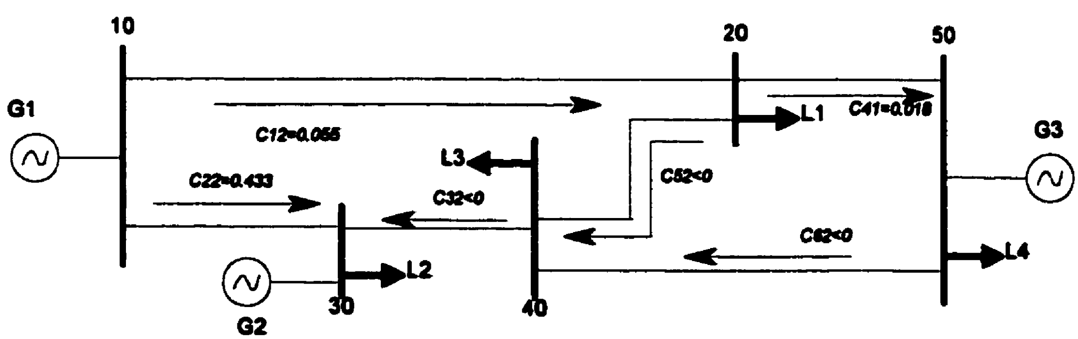

Figure 5.3. Contributions to load 2 with VPX method

5.6.2 Allocated Network Costs

The allocated network costs for each load point are summarized in Table 5.4, assuming one unique methodology for computing individual asset costs for both algorithms.

Table 5.4. Allocated Costs

Load	Image Algorithm	VPX Method	Difference (%)
1	9.486	9.971	5.11
2	1.280	1.689	31.95
3	2.996	2.705	-9.71
4	14.982	14.381	-4.01

As can be observed from table 5.4, the costs allocated to loads 1 and 2 with the image domain algorithm are higher than those obtained with VPX method, and the costs allocated to loads 3 and 4 are lower.

In general, costs allocated to a given load increase when more lines feed this load. This is generally the case with the VPX algorithm as can be observed from Table 5.4.

The biggest difference is seen in the allocated costs for load 2. This is because when image domain is applied only line 2 is contributing to the load. Instead, when VPX method is used all lines contribute to the "fault" in the load point 2 and those with positive flows towards bus 30 are assumed to contribute to this load (lines 1, 2 and 4). In this example, the additional two lines, line 1 and 4 have very substantial asset values ($6M and $5M, respectively) as compared with the asset value of line 2 ($2.9M).

Such a large difference of 31.95% could cause important economical effects when considering as big electrical system as Ontario's.

By contrast, load 3 allocation cost is 9.71% lower using VPX method. This is mainly because of smaller contributions (0.284 pu and 0.353 pu) lines 2 and 3 make to load 3, respectively when VPX is applied instead of 0.4336 and 0.7714 pu when image algorithm is used. Those lower contributions of lines 2 and 3 to load 3 with the VPX method are due to the fact that lines 1 and 4 are also feeding load 3. The contributions of lines 2 and 3 are large enough to negate contributions of lines 1 and 4 in the VPX approach that are not present in the Image Domain algorithm.

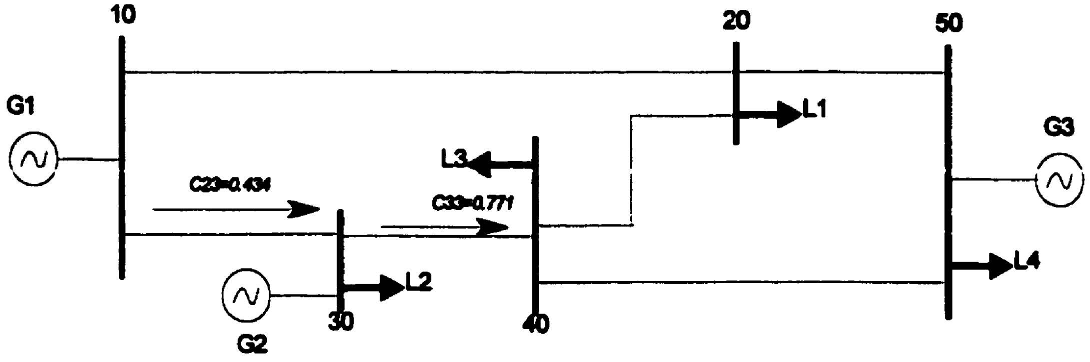

Figure 5.4. Contributions to load 3 with image domain algorithm

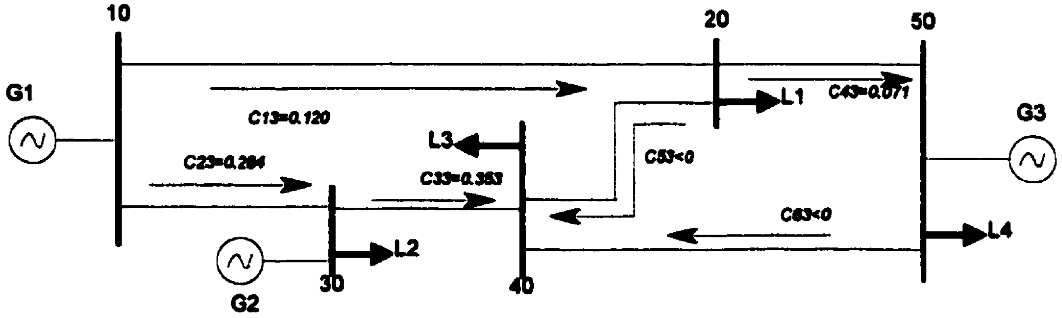

Figure 5.5. Contributions to load 3 with VPX method

Besides, the VPX method considers the effect of incremental changes in bus power injections and their incremental effect on network flows.

The image domain approach, on the other hand, is not an incremental method; that is, it does not say anything about what would change if a small change were introduced in one of the variables. Instead, it provides a rigorous and accurate characterization of the flows and injections for a specific system condition. There is, therefore another cause of difference among the results.

That is why there is no contradiction when the image domain method shows that a particular injection does not contribute to the flow in some lines while sensitivities indicate that a change in this injection would have an effect on *all* line flows. Besides its simplicity and transparency, the proposed method has therefore the added advantage that its results are independent of the arbitrary choice of a slack bus.

Both methods relay on certain assumptions and the validity of these assumptions can be forcefully defended by the proponents of both approaches. We cannot say that one method is better than the other. Our choice will depend on the acceptance criteria of the assumptions and the ease of implementation of the method selected. However, it is expected that both methods would give similar results for a large system with possible significant differences in small pockets of the network.

However, the charges obtained with any of these methods should not be used as the sole signal for taking investment decisions for generation or transmission expansion because they do not reflect the level of spare capacity in the existing system. It is appropriate to use locational marginal cost as a complementary method to give these signals and to charge for losses and congestion in the transmission system.

6 SAMPLE CALCULATIONS AND SOFTWARE DESCRIPTION

6.1 Introduction

Based on the discussion in Chapter 5, the Image Domain algorithm was found more transparent and more easily applied. Therefore, it was selected for the studies of the Ontario transmission system.

This chapter presents the necessary information for carrying out the allocations of transmission costs based on usage for the OHSC system. At the end, the main features of the computer program developed for this purpose are discussed.

6.2 System Data

The following is the input data required for carrying out the contribution computations.

- Load flow raw data file.
- Load flow results table for each scenario.
- List of all load buses with nonzero loads in the load flow.
- List of branches in the load flow file with nonzero flows in at least one direction.
- Table with operating designations and ownership information for all assets.

Besides, there is other data which must be considered to compute allocation costs of asset categories according to the regulation.

- Translation table from load flow raw data bus numbers to delivery point names.
- Table with asset id numbers.
- Translation table of asset id information to load flow branch designation table.

6.2.1 List of all load buses with nonzero loads in the load flow

The input data for this table is the load flow raw data file. A sample of this list is shown in the table 6.1.

Table 6.1. Sample table of loads

1	600	45.185	21.883
2	601	52.368	25.368
3	608	16.372	5.076
4	609	31.812	11.033
5	616	50.889	18.378
6	622	80.705	38.174
7	623	41.406	20.05
8	624	46.573	22.552
9	630	18.094	15.339
10	631	1.74	0.21
11	632	2.41	0.39
12	634	2.41	0.39
13	650	2.604	1.256
14	652	6.565	3.181

In the load flow case studied, there are 705 load points.

6.2.2 List of branches in the load flow file with nonzero flows in at least one direction

The data in this table is taken from load flow raw data file and load flow result file. A sample of this list is shown in the table 6.2.

For the purpose of the image domain algorithm, the asset rating, resistance and reactance columns are not necessary, because those parameters are taken into account in the load flow computation. Those columns are considered for offering a complete information of the system.

Table 6.2. Sample table of branches

1	103	T1	Hawthorne TS	Hawthorne TS	TNAM		0	315	-314.4	0.00022	0.02188	0
1	103	T2	Hawthorne TS	Hawthorne TS	TNAM		0	350.7	-350.3	0.00026	0.01965	0
1	103	T3	Hawthorne TS	Hawthorne TS	TNAM		0	351.6	-351.2	0.00026	0.0196	0
1	685	T2	Hawthorne TS	Hawthorne TS	TNAM		0	-19.7	19.7	-0.03285	-0.3416	0
1	686	T3	Hawthorne TS	Hawthorne TS	TNAM		0	-19.9	19.9	-0.03266	-0.339	0
100	146	1	Chats Falls TS	South March	TNAM		733.9	138.9	-138.2	0.00303	0.02941	29
100	907	20	Chats Falls GS	Chats Falls GS	GENCO		0	-46.2	46.5	0.01066	0.22777	0
100	908	30	Chats Falls GS	Chats Falls GS	GENCO		0	-8.4	8.4	0.01205	0.27297	0
100	909	30	Chats Falls GS	Chats Falls GS	GENCO		0	-31.4	31.6	0.01195	0.2702	0
100	1149	1	Chats Falls TS	Havelock TS	TNAM		346.6	-8.2	8.2	0.03006	0.17963	171.8
100	1161	1	Chats Falls TS	Marine JCT	TNAM		346.6	1.7	-1.7	0.03412	0.22403	215.2
101	302	T4	Chenaux TS	Chenaux TS	TNAM		0	37	-36.4	0.0024	0.07881	0
101	303	T3	Chenaux TS	Chenaux TS	TNAM		0	58.9	-58.6	0.00373	0.12118	0
101	910	T1	Chenaux GS	Chenaux GS	GENCO		0	-28.3	28.4	0.00388	0.20724	0
101	911	T1	Chenaux GS	Chenaux GS	GENCO		0	-28.2	28.3	0.00392	0.21148	0
101	912	T2	Chenaux GS	Chenaux GS	GENCO		0	-28.3	28.4	0.00388	0.20724	0
101	913	T2	Chenaux GS	Chenaux GS	GENCO		0	-28.1	28.1	0.00392	0.21148	0
102	144	1	Des Joachims	Otter Creek	TNAM		305.8	127.7	-125.7	0.01481	0.09171	89.5

6.2.3 Table with operating designations and ownership information for all assets

The list of input data contained in table 6.3 was used for getting operating designations and owners for all the branches.

Table 6.3. Sample table of other input data

Trans	1137	1954	01	Kingston Co-gen CGS		MT_001	DESTEC ENGINEERING
Trans	5004	5132	01	Beck #2 TS		T301	TNAM
Trans	1139	1953	02	Kingston Co-gen CGS		MT_002	DESTEC ENGINEERING
Trans	5005	5133	02	Beck #2 TS		T302	TNAM
Trans	6105	5555	10	Kitchener MTS#5		T10	KITCHENER WILMOT
Trans	6106	5555	10	Kitchener MTS#5		T10	KITCHENER WILMOT
Trans	5402	6306	10	Beck GS #1		T10	GENCO
Trans	9356	9625	10	AvenorThundr Bay		T10	AVENOR
Trans	344	906	10	Chats Falls GS		T10	GENCO
Trans	2933	2945	11	Pickering NGS A		44SS11	GENCO
Trans	2945	2946	11	Pickering NGS A		44SS11	GENCO
Trans	2933	2946	11	Pickering NGS A		44SS11	GENCO
Trans	6919	6920	11	Bruce NGS A		SS11	GENCO
Trans	6900	6919	11	Bruce NGS A		SS11	GENCO
Trans	6900	6920	11	Bruce NGS A		SS11	GENCO

6.2.4 Delivery points table

According to one of the possible policies to recover transmission costs proposed for the Ontario electricity market , OHSC would charge each delivery point, which is the point of supply to the customer, or group of customers from the transmission system, in proportion to their use of the transmission assets.

The input data described in the sections above is used to compute the contribution of each load point to flow in lines, as described in Chapter 4.

Once these contributions are computed, a separate table (sample Table 6.4) is required to translate the load point number to the delivery point name.

Table 6.4. Sample translation table from the load point number to the delivery point name

390	6103	Kitchener MTS#4	197
391	6104	Kitchener MTS#4	197
394	6107	Kitchener MTS#6	199
426	6221	Niagara-on-the-lk DS	276
425	6220	Niagara-on-the-lk DS	276
664	9714	Noranda Hemlo CTS	277
55	766	Overbrook TS	294
410	6175	Palermo TS	296
56	771	Pembrooke TS	299
618	8830	Whitefish Falls DS	404
305	4770	Woodbridge TS	410
306	4772	Woodbridge TS	410

6.2.5 Table with asset id numbers

As was mentioned in Chapter 2, the most likely policy to share transmission costs among customers in Ontario would be through three types of pools: network assets, transformation connection and line connection.

Two different types of asset identification tables were used to assign each asset to one of these pools. One table contained asset ids for the transmission lines and the other identification of branches at substations.

In about 80% of the cases, each branch has a unique asset id number. In the remaining 20% of the cases there are more than one asset id.

6.2.5.1 Line branches

For some transmission line assets, up to four different asset id numbers are assigned to the branches. In those cases, all asset id numbers were entered in the final table.

Table 6.5. Sample table of Line Asset IDs

6	Chats Falls TS	South March TS	59793
7	Chats Falls TS	Havelock TS	76065
8	Chats Falls TS	Marine JCT	54933
11	Des Joachims TS	Otter Creek JCT	64491
13	Des Joachims TS	Minden TS	53806
13	Des Joachims TS	Minden TS	58692
13	Des Joachims TS	Minden TS	64491
14	Des Joachims TS	Minden TS	53806
14	Des Joachims TS	Minden TS	58692
14	Des Joachims TS	Minden TS	64491
15	Des Joachims TS	Minden TS	53806
15	Des Joachims TS	Minden TS	58692
15	Des Joachims TS	Minden TS	64491

6.2.5.2 Station branches

For station assets, up to three different asset id numbers, one for each type of pool, could be associated with this branch because these stations are serving a dual or triple role. For example, Manby TS has part of the station as "Network" with one asset number, one part is "Line Connection" (it just transforms voltage for sub-transmission distribution to other load serving stations) with an asset number for that part, and one part is "Station Connection" (it serves the load right off Manby) with an asset number for that part.

Table 6.6. Sample table of Station Asset IDs

646	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
647	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
648	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
649	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
650	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
651	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
654	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
655	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
656	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
657	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
658	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
659	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
660	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
661	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
662	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
673	Leaside TS	Leaside TS	N,SC	05418		00223
682	Manby TS	Manby TS	N,LC,SC	04401	00175	00169
686	Manby TS	Manby TS	N,LC,SC	04401	00175	00169

N = Network asset
LC = Line connection asset
SC = Station connection asset

6.3 Transmission usage by loads

The aim was to produce a table showing the relative Utilization Share of (Individual) Transmission Assets (USTA) for each delivery point of the transmission system owned by OHSC. The algorithm used for the computation of USTA coefficients was the Image Domain, discussed in detail in the Chapter 4.

Four load flow scenarios for the year 2000 were used in this study: Winter, Spring, Summer and Fall and the corresponding four USTA tables were produced. The transmission network was the same for all the cases and only loads and dispatched generation were different. There are 413 delivery points off the transmission system, which comprises 2838 TNAM assets used for the delivery of electricity.

The USTA tables are composed of two parts. The first part contains asset information and the second the usage coefficients. Only some of the columns with USTA coefficients are shown for demonstration purposes.

The table below shows sample entries in the USTA table. Three different cases were selected for illustration.

The first five lines represent Hawthorne TS branches with three transformers. All the branches have two identical asset ids.

Branch number 6 has a unique asset id. Branches 7 to 9 represent four lines. All four have the same asset id No.1. The middle three lines have a second asset id.

The percentage split columns are based on flows for branches 1 to 5 and based on lengths for branches 7 to 10.

Table 6.7. Sample of a USTA table with asset information

[redacted]

1	1	103	Hawthorne TS	Hawthorne TS	T1	T1	TNAM	0	315	0
2	1	103	Hawthorne TS	Hawthorne TS	T2	T2	TNAM	0	350.7	0
3	1	103	Hawthorne TS	Hawthorne TS	T3	T3	TNAM	0	351.6	0
4	1	685	Hawthorne TS	Hawthorne TS	T2	T2	TNAM	0	-19.7	0
5	1	686	Hawthorne TS	Hawthorne TS	T3	T3	TNAM	0	-19.9	0
6	100	146	Chats Falls TS	South March TS	1	C3S	TNAM	733.9	138.9	29
1491	5560	5606	Kitchener MTS #6	Siebert JCT	1	D9G	TNAM	288.8	105.2	4.2
1519	5606	5497	Siebert JCT	Freeport JCT	1	D9G	TNAM	288.8	70.7	2.3
1517	5605	5496	Siebert JCT	Freeport JCT	1	D7G	TNAM	288.8	72.3	2.3
1490	5559	5605	Kitchener MTS #6	Siebert JCT	1	D7G	TNAM	288.8	105.2	4.2

[redacted]

1	07046	NA	00199	NA	1		1		0.2980		0.2980	
2	07046	NA	00199	NA	2		2		0.3318		0.3318	
3	07046	NA	00199	NA	3		3		0.3327		0.3327	
4	07046	NA	00199	NA	4		4		0.0186		0.0186	
5	07046	NA	00199	NA	5		5		0.0188		0.0188	
6	59793	NA	NA	NA								
7	11997	NA	NA	NA	1				0.3231			
8	11997	98166	NA	NA	2	1			0.1769	0.5		
9	11997	98166	NA	NA	3	2			0.1769	0.5		
10	11997	NA	NA	NA	4				0.3231			

1	0	0	6.553922E-03	0.1141793	3.720175E-03	6.317575E-02	5.132283E-03	3.343668E-02		0.999995
2	0	0	6.553922E-03	0.1141793	3.720175E-03	6.317575E-02	5.132283E-03	3.343668E-02		0.999995
3	0	0	6.553922E-03	0.1141793	3.720175E-03	6.317575E-02	5.132283E-03	3.343668E-02		0.999995
4	0	0	6.553921E-03	0.1141793	3.720174E-03	6.317575E-02	5.132282E-03	3.343668E-02		0.999995
5	0	0	6.553921E-03	0.1141793	3.720174E-03	6.317575E-02	5.132282E-03	3.343668E-02		0.999995
6	0	0	0	0	0	0	0	0		1
7	0.2478551	0.1651526	0	0	0	0	0	0		0.999995
8	0	0.2450425	0	0	0	0	0	0		0.999995
9	0	0.2461964	0	0	0	0	0	0		0.999995
10	0.2345091	0.1696854	0	0	0	0	0	0		0.999995

There are two possible approaches to assigning the asset identification to the components in the second category of station assets.

In one case, the multiple asset id numbers could be treated the same way as multiple asset ids assigned to lines (this approach is reflected in table 5.7).

In another approach, a single asset id number could be assigned to each station branch. In order to assign a unique asset number for each branch at a substation, an analysis of each case should be conducted by drawing a diagram based on the load flow connectivity information. The aim of the analysis would be to determine whether the asset can be classified as a part of the network, station connection or a line connection. In general, one could assume that the EHV kV branches that are portions of a substation are part of the "Network" and the associated branches would be assigned the Asset Number that is classified as "N". The 230/115 kV step-down transformers would be classified as "Line Connections" and the associated branches would be assigned the Asset Number that is classified as "LC". Finally, the part of the station that supplies load (for example 230/44 kV or 115 / 44 kV) or to those branches that step down to the lowest voltage in the station (i.e. from 115 kV or 230 kV to 44 kV, for example), would be assigned the Asset Number that is classified as "SC".

At this stage of the project a decision was made to produce the USTA tables with four asset id columns reflecting all the information obtained from OHSC.

Once the asset id column has been filled in, the subasset id and the percentage of asset columns were filled in as follows.

- If two or more branches representing transmission lines have the same asset id (or, in the case of multiple asset id designations, all the ids are the same), the subasset id designations were assigned as consecutive numbers. The percentage of use is based on the length of the corresponding lines.

- If two or more branches belonging to a substation (e.g., transformers) have the same asset id, the subasset id designations were assigned as consecutive numbers and the percentage of subasset is based on the percentage of the loading. Note that since these percentages are dependent on the load flow case studied, the percentages can be somewhat different for different load flow scenarios.

6.4 Cost Allocation

The following table illustrates how the cost allocation could be computed in a general case with multiple asset id numbers.

Table 6.8. Example of computation of cost allocation with multiple asset id numbers

Sample Calculation for Many-To-Many Line and Station components Assets

	Asset ID					Sub_asset ID				% of subasset				
	Id_1	Id_2	Id_3	Id_4		Sub_Id 1	Sub_Id 2	Sub_Id 3	Sub_Id 4	%1	%2	%3	%4	
Line					**Length**									**Allocation**
A	11111	22222			7	1	1			0.4375	0.466667			4.083333
B		22222	33333		8		2	1			0.533333	0.470588		5.490196
C	11111		33333		9	2		2		0.5625		0.529412		5.426471
Asset $	4	5	6											15
Station branch					**Flow**									
X	44444	55555	66666		100	1	1	1		0.333333	0.25	0.25		9.083333
Y	44444				200	2				0.666667				6.666667
Z		55555	55555		300		2	2			0.75	0.75		17.25
Asset $	10	11	12											33

For example, the cost allocation for line A is obtained as follows.

The first percentage values of subassets are equal to:

$$\%1 = \frac{7}{7+9} = 0.4375; \qquad \%2 = \frac{7}{7+8} = 0.466667$$

The cost allocation is then obtained as:

$$Allocation(A) = 4 \times 0.437 + 5 \times 0.46667 = 4.08333$$

Similar computations are performed for station branches with the length replaced by flows.

The final step is to allocate those costs in the last column of the table 6.8, among the delivery points according to the contributions factors.

6.5 Software description

The software developed for implementing image domain algorithm is described in the Figure 6.1 below.

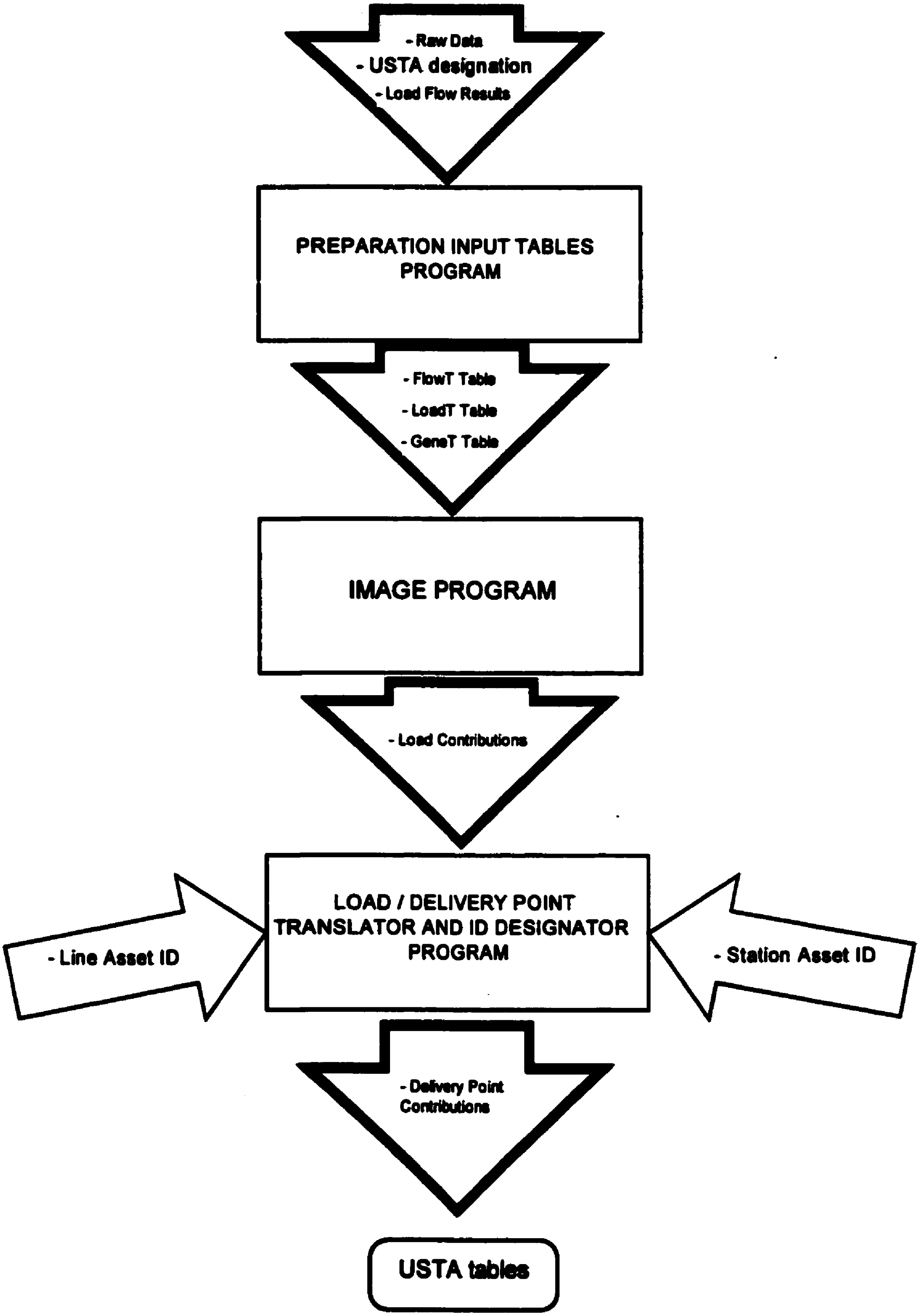

Figure 6.1. Image Domain Scheme

7 CONCLUSIONS

In this thesis, a presentation of the transmission pricing background was made, including the economical principles for charging for transmission services and a method for computing the individual costs of transmission assets.

The image domain and the VPX method were applied on an small test network, finding out that the choice of the method to be applied will depend on the acceptance criteria of the assumptions and the ease of implementation of the method selected.

The image domain method was selected because its justification is more transparent and easier to understand by the users that have to pay for the transmission service. Besides it has the added advantage that its results are independent of the arbitrary choice of a slack bus.

A computer program was written to implement the usage domain method. The algorithm can be modified to calculate the following additional quantities.

- Generator contributions to power flow.
- Contribution of generators to loads.
- Contribution of loads to power losses.
- Contribution of generators to power losses.

It was applied in the Ontario system to define the contribution of loads to the flow in the lines during the transition period of the new market structure. A brief description of the input and output files and the procedure to obtain the contributions of the delivery points, or group of loads of the system, is also presented.

The charges obtained with this method should not be used as the only signal for taking investment decisions for generation or transmission expansion because they do not reflect the level of spare capacity in the existing system. It is appropriate to use locational marginal cost as a complementary method to give these signals and to charge for losses and congestion in the transmission system.

This algorithm can be applied to any electricity system and it can be used not only for allocating congestion and losses costs but also for planning future investments.

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APPENDIX A - Mathematical considerations for the image domain method

Proportionality Assumption

The calculation of the use of the network by each load requires the source of generation for each load to be identified. This requires an assumption to be made since in electrical networks is not possible to identify the source of generation that supplies a particular load.

The proportionality justification is that it appears more reasonable than any other possible assumption. These other possible assumptions would imply that at a given bus, the power traceable to other loads is disproportionately transmitted through this bus from other generators. Considering that the bus is reached by a fixed set of generators that have a flow path towards this bus, these assumptions do not seem to have any reasonable physical basis.

The proportionality assumption leads to the following fundamental results.

Theorem 1

The contribution of power flow in line K (carrying power to a node) to power flow in line L (carrying power out off the node) is equal to a ratio of power flow in line L to a sum of power flows out off this node. Thus, denoting this contribution by $C_L(K)$, we have

$$C_L(K) = \frac{P_K^{out}}{\sum_{j=1}^{N} P_J^{out}} \qquad \text{(A1)}$$

where N is the number of lines connected to this node with power flows out of the node.

Proof

Let flows into a node are $P_1^{in}, P_2^{in}, \ldots P_M^{in}$ and the flows out of this node are $P_1^{out}, P_2^{out}, \ldots P_N^{out}$. Let us denote the fraction of the flow contributed by line K towards the flow into the node, by $F_{in}(K)$. Thus,

$$F_{in}(K) = \frac{P_K^{in}}{\sum_{J=1}^{M} P_J^{in}} = \frac{P_K^{in}}{\sum_{J=1}^{N} P_J^{out}}$$

where the last equality follows from KCL.

From the assumption of proportionality, flow in line K contributes the same fraction to the outflow of the node. Thus, the flow in line L attributed to the flow in line K, denoted by $P_L(K)$, is equal to

$$P_L(K) = F_{in}(K).P_L^{out} = \frac{P_K^{in}.P_L^{out}}{\sum_{J=1}^{N} P_J^{out}} = P_K^{in}.\frac{P_L^{out}}{\sum_{J=1}^{N} P_J^{out}}$$

Hence,

$$C_L(K) = \frac{P_K^{out}}{\sum_{J=1}^{N} P_J^{out}}$$

Theorem 2

Contribution of line K carrying power to a node to power flow in all lines L (carrying power out off this node) is equal to 1.0 p.u.

Proof

$$\sum_{L=1}^{N} C_L(K) = \sum_{L=1}^{N} \frac{P_L^{out}}{\sum_{J=1}^{N} P_J^{out}} = \frac{\sum_{L=1}^{N} P_L^{out}}{\sum_{J=1}^{N} P_J^{out}} = 1.0$$

Definition 1

A domain of a load is a set of lines that have the flow contributing to this load. A subdomain of the load Li to the line L is a subset of the domain of load Li such that all paths in this subdomain terminate at line L.

A domain of a load contains all possible paths between buses in the system and this load so that a flow can be traced between a given bus and the load. A subdomain of load Li and line L contains all possible paths between this load and the receiving bus of line L that are a subset of the domain of load Li.

The concepts introduced so far can now be used to prove the following theorem fundamental to the proposed algorithm.

Theorem 3

Let paths 1, 2, ..., p, belong to the subdomain of load Li to line L (load Li is connected to bus I). Let lines $L_{n_1}, L_{n_2}, ..., L_{n_n}$ belong to a path n with numbering starting from bus i towards line L. The contribution of load Li to the flow in line L is obtained from the following expression.

$$C_L(Li) = \sum_{n=1}^{p} \left[\prod_{k=1}^{n-1} C_{Ln_k}\left(L_{n_{k+1}}\right) \sum_{K \subset NL} \left(1 - C_{L_{n1}}(K)\right) \right] \tag{A2}$$

where

$K \subset NL$ is a set of lines that have line L_{n_1} in their domains

$C_{L_{n_k}}\left(L_{n_{k+1}}\right)$ is a contribution to the flow in line L_{n_k} by line $L_{n_{k+1}}$

Proof

The procedure is built recursively. We will start with line L_{n_1} connected to bus i. From the definition of the image domain of this line, the contribution of load Li to the flow in this line is equal to

$$C_{L_{n1}}(Li)=\sum_{K\subset NL}\left(1-C_{L_{n1}}(K)\right)$$

Consider now line L_{n_2}. This line is the image domain of L_{n_1} and it contributes $C_{L_{n1}}\left(L_{n_2}\right)$ of its flow towards the flow in line L_{n_1}. Therefore, the contribution of load Li to the flow in L_{n_2} is equal to $C_{L_{n2}}(Li)=C_{L_{n1}}\left(C_{L_{n2}}\right)C_{L_{n1}}(Li)=C_{L_{n1}}\left(C_{L_{n2}}\right)\sum_{K\subset NL}\left(1-C_{L_{n1}}(K)\right)$

Through mathematical induction the contribution of load Li to the flow in L_{n_n} is obtained as

$$C_{L_{nn}}(Li)=C_{L_{nn-1}}\left(C_{L_{nn}}\right)\cdot\ldots\cdot C_{L_{n1}}\left(C_{L_{n2}}\right)\cdot C_{L_{n1}}(Li)$$

Summing now over all paths, the equation (A2) is obtained.