CHAPTER 1

INTRODUCTION

1.1 Motivation

The electricity utility industry, the last major regulated monopoly to undergo restructuring, is in the middle of the most turbulent period in its history. A number of driving forces, including the environment, technology advances, legislative/regulatory initiatives, and market pressures, are bringing major changes to the industry. The rapid disintegration of the vertically integrated electric power industry, the functional unbundling of transmission and generation services and the unbundling of *ancillary services* from transmission services are among the most important ones occurring [1]. There are, in addition, major developments underway to bring about full competition in many sectors of the electricity business. From the very beginning it was realized that transmission is at the heart of the effective development of competitive electricity markets. The functional unbundling is the basis for the implementation of nondiscriminatory open access transmission. It serves to spur competition and results in the entry of new market players and the proliferation in the number and the volumes of transactions. It is the unbundled services and the proliferation of transactions in the open access regime that provides the motivation for the work in this thesis. This thesis focuses on the management and allocation of unbundled services in multiple-transaction networks. The three services addressed in the thesis are real transmission losses, generator-provided reactive support and the transmission congestion management.

1.1.1 The beginning of the breakup of the vertically integrated utility structure

The generation, transmission, and distribution of electric power to end users have been historically viewed as the functions of a natural monopoly. Utilities typically were granted exclusive franchise/service territories with protected captive markets. In return for these grants, the utilities were obligated to serve all customers within this franchise territory on a nondiscriminatory basis at *tariff rates*. The rates of the regulated monopoly were set by the regulatory agencies and were cost based, resulting in a utility being considered as a cost-plus business. The traditional structure of the electric utility industry resulted in a number of distinctive characteristics including low efficiency and lack of customer choice.

In this vertically integrated utility (VIU) structure, the transmission system is built and operated very much in a supportive role to ensure that the utility's generation output could be delivered to serve the utility's *native load customers*. Transmission systems were interconnected to ensure reliability and to construct ties to support interutility transactions. Under the industry organization in place, all the facilities and the loads served are owned/controlled by the utility. All the utility's services were bundled, and all the costing was performed on a bundled basis.

The 1950s and 1960s constituted the golden era for electric utilities. The industry went through an incredible expansion, with electricity demand growing at rates of approximately 7% each year. Economies of scale marked this time period as ever larger plants were built at lower costs per megawatt of capacity. During this time the price of electricity continued to drop even as the demand increased.

The 1970s, however, brought about a decade with many changes. Oil prices increased dramatically during and after the 1973-1974 oil embargo. This, with high inflation and interest rates, resulted in increased energy costs. As a result of these events, the United States began to strive for energy self-sufficiency. Energy conservation programs increased in number, and the development of renewable energy sources was begun in earnest. Under these circumstances, the *regulatory compact* began to unravel and a new era for the utilities began.

The Public Utility Regulatory Policies Act (PURPA) of 1978 [2] put an end to the electricity generation monopoly that the utilities enjoyed up to that time. PURPA introduced new electricity generation entities known as qualifying facilities (QF) into the wholesale electricity markets. Utilities were obliged to purchase power from a QF at *avoided cost*. The advent of new generating entities such as independent power producers (IPPs) and QFs put new pressure on the transmission owning utilities (TOUs) for access and service. These players were particularly interested in tapping into the higher-price electricity markets if they could find a way to *transport* their outputs from the generation site to other regions. However, the structure of the VIU despite the advent of new players did not change, as seen in Figure 1.1. The ability of these nonutility generators to obtain transmission services from the TOUs was very limited.

There were several major developments on the legislative and regulatory fronts aimed at addressing the issue of opening up the transmission system to provide nondiscriminatory transmission services to interested entities. A very important piece of legislation, the National Energy Policy Act (EPAct) was enacted in 1992 [3]. EPAct transmission requirements allow any electric utility, federal marketing agency, or person generating electric energy for sale at wholesale to request transmission service from a TOU. By broadening the power of FERC to mandate wheeling by TOUs, EPAct made possible the start of the transmission open access regime in North America. Using its newly enlarged authority, FERC undertook a series of highly important rulings that brought about fundamental changes in the electricity business.

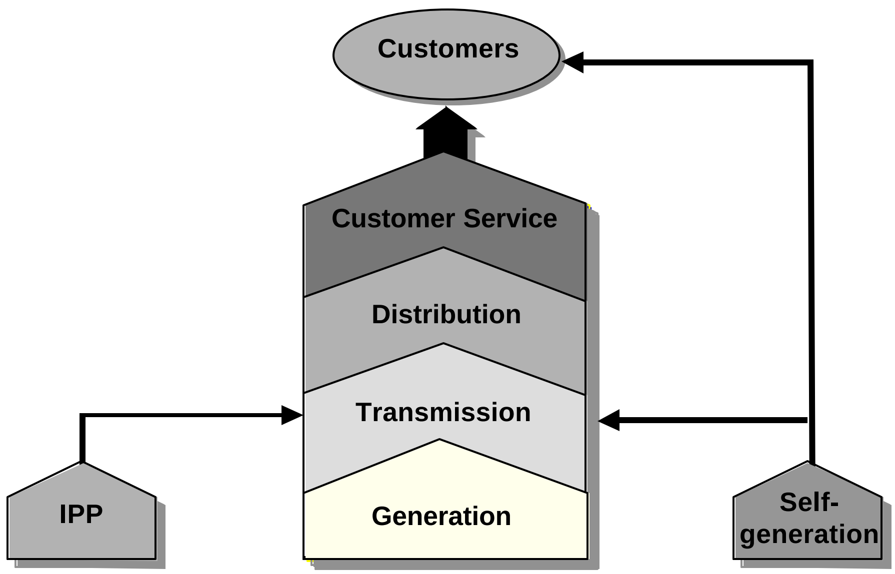

Figure 1.1. The structure of the VIU industry: all the generating entities depend on the transmission service provided by the transmission-owning entity.

On April 24, 1996, FERC issued Order No. 888 [4] and Order No. 889 [5] that defined the regulatory structure for the establishment of an open access transmission regime. The Orders constitute a generic remedy for the undue discrimination in the industry' past practices in providing transmission services. They serve to aggressively promote robust competition in wholesale markets and to establish standards for recovering stranded costs. Since the issuance of these Orders, a number of competitive electricity markets have been created. They include California [6], the Pennsylvania-New Jersey-Maryland (PJM) Interconnection [7], New England [8], and New York [9].

1.1.2 Open access transmission regime

The FERC Orders [4] [5] laid out the regulatory structure of the open access transmission regime. The major thrusts of the Orders were to require transmission owners to provide nondiscriminatory open access through tariffs of general applicability, to functionally unbundle transmission and generation, and *ancillary services* from transmission services, and to establish a *Chinese wall* between the transmission and other parts of the utility. The requirements in these Orders resulted in fundamental changes in the functions and operations of electric utilities.

The FERC Orders together with subsequent decisions serve to transform transmission into adopting a *common carrier* role. Figure 1.2 depicts the use of the transmission system in such a mode. A key impact of the *common carrier* transmission network is the utilization of the transmission grid in very different ways than those for which it was planned. This is due in large part to the proliferation in the number of transactions and the increasing number of new players who are transmission customers. The increasing number of users of the system, the greater volume and variety of transactions involving transmission, and the increasing volatility in generation patterns lead to more frequent encounters with the grid constraints. An indication that the increased and different use of the transmission system is stressing the grid is the increased invocation of the NERC developed transmission loading relief (TLR) procedures [10].

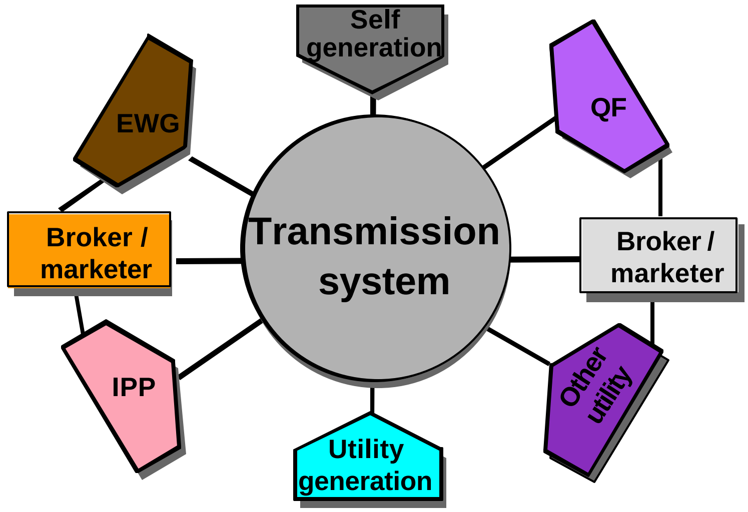

Figure 1.2. The use of the transmission system in the *common carrier* mode

It is important to note that the principal technical considerations under open access are the same as in the VIU environment. The physical characteristics of the electric transmission system remain unchanged under open access. The system must be protected against violations of its physical, operational, and technical/engineering limits. Under open access, the system security monitoring, analysis, and control functions remain unchanged but may be placed in hands different from those in the VIU structure. The protection of the system from overstress due to the proliferation of transactions, the large number of players, and the new *rules of the road* remains a basic requirement for reliable electricity.

A second and equally important development is the breakup of the VIU structure into various separate components. Developments both on the regulatory front and in the evolving markets are resulting in the unbundling of services with energy being completely separated from transmission, the provision of basic transmission service to all eligible entities, and the provision of all ancillary services as individual services.

Ancillary services are system support services that are essential for physical delivery of energy from a source point to a load point. Such services are fundamental and indispensable system services required for the provision of transmission service, and in their absence instantaneous system collapse would result. FERC specified in [5] a list of six mandated ancillary services that are required to be provided/acquired on an unbundled basis. The list consists of: scheduling, system control, and dispatch; reactive power and voltage control from generating sources; regulation and frequency response; energy imbalance; spinning reserves; and supplemental reserves. These six services are provided mostly by generation sources. A transmission customer must purchase from the transmission provider or self-provide these services. Note that the FERC list of ancillary services is by no means exhaustive. For example, NERC has developed a set of so-called *interconnected operations services* (IOSs), which include the six FERC services as a subset [11], [12]. The real power transmission losses service, which is not included in FERC's list of ancillary services, is listed as one of the IOSs.

1.1.3 The independent grid operator (IGO) concept

The unbundling brought about by the FERC Orders serves to spur competition, resulting in the entry of many new market players and the proliferation of financial and physical flow transactions. These changes are leading to the restructuring of the organizational structure of the industry. A major development is the introduction of the independent system operator (ISO) concept and the setting up of such entities in various regions of the nation including California [6], PJM [7], New England [8] and New York [9]. The motivation for the ISO concept stems from the FERC policies that make it clear to transmission utilities that the “transmission and …” business would be difficult, problematic, and possibly of limited strategic value. In light of the increasing volume of transactions in each region, the need to solve transmission problems on a regional basis became critically important. In addition, the facilitation of the commercial market by an independent entity can remove impediments to grid access and can provide transmission service.

In [4], FERC set out a number of principles with which a properly constituted ISO must comply. The basic requirement is compliance with FERC’s nondiscriminatory transmission service and tariff provision. However, different versions of the ISO concept are evident from the existing and planned implementations.

There are major issues in open access that have frustrated the attainment of universal nondiscriminatory transmission service for all eligible players. The functional unbundling adopted by FERC has not resulted in the desired separation of transmission and merchant functions. Transmission providers employ subtle means to frustrate competition. To address these issues, FERC issued its Order 2000 [13] on December 20, 1999, to evolve the ISO concept into a broader regional transmission organization (RTO) notion. RTO is a generic term for a new *independent* transmission management structure that will control transmission operations and planning uniformly in large regions. An RTO is an independent entity with responsibility for the reliable operation, maintenance, and expansion of a geographically widespread grid. In [13], FERC established four minimum characteristics and eight basic functions for an RTO.

For the purposes of this thesis, we adopt the notion of a *generic* independent grid operator (IGO) which embodies the ISO and/or RTO roles and responsibilities. The principal role for the IGO is to facilitate markets, i.e., to attempt to enable the undertaking of as many transactions as possible by the various market players. This role is discharged under the constraint of maintaining the reliability and security of the interconnected system. One of the key characteristics for the IGO is that it is independent of all entities under its control and that it has no ownership/financial interests in any of these entities. The purpose of the independence principle is to ensure that the IGO will provide transmission service and operate the grid in a nondiscriminatory manner.

1.1.4 Unbundled service management and allocation

Two of the key functions of the IGO are the management of ancillary services and transmission congestion. The IGO's ancillary service management requires the acquisition/provision of the ancillary services in conformance with FERC regulations. Since the ancillary services need to be procured by the IGO from the generators and/or loads connected to the grid, the appropriate cost/price structure is a major issue. In addition, the entry of a large number of new players and the proliferation of transactions have resulted in the need for the IGO to determine the allocation of the ancillary service requirements and the corresponding costs/prices to each individual transaction. In this way, no transaction has to bear some other transaction's charges. Also for each transacting entity it would be desirable to have *a priori* information to evaluate the impacts of various contemplated transactions. The two ancillary services whose allocation and management issues are addressed in the thesis are transmission real power losses and reactive support service from generation sources.

While real power loss compensation is a service that is relatively straightforward to understand at least conceptually, the reactive support service is a rather complex phenomenon. The maintenance of an acceptable voltage profile is a key requirement for system integrity; this, in turn, sets up the need for reactive power injections at various buses of the system. This need for reactive power support is a *system requirement* and its provision is an intrinsic part of transmission service. Reactive power requirements may vary with time, location, and control response in addition to the magnitude and nature of transactions in place. Moreover, transmission users connecting to the network may "consume" reactive power in addition to real power, and this sets up a need for reactive power due to the nature of the load and is a *local* reactive support requirement. In addition, reactive reserves are required for maintaining voltages at appropriate levels during contingencies. Under open access, *reactive support and voltage control from generation sources* becomes one of the six ancillary services specified in [5] that the IGO is responsible for acquiring from various generators that are *independent* of the IGO. The reactive power and voltage control service must be provided to all transactions and must be purchased by all transactions. A transparent allocation scheme of the reactive support requirements can provide useful *a priori* information to the market participants who consider possible transactions. Also, once the amount of reactive support requirement provided by various generators for each transaction is determined, the generators can be appropriately compensated.

When the limited transfer capability of the transmission network is unable to accommodate all the desired transactions, we say transmission congestion occurs. The task of transmission congestion management requires the IGO to identify and relieve such situations. The terminology of transmission congestion does not exist under the VIU structure. The utility company, which is the central decision-maker, explicitly takes transmission constraints into consideration in its determination of the operating schedules so that the transmission is used in such a way that all the constraints taken into consideration are satisfied. In the new environment, however, the open access transmission regime results in the more intensive use of the transmission system, which, in turn, leads to more frequent congestion. Moreover, the IGO's congestion management essentially determinates the actual transmission usage for the individual transactions and consequently has direct and significant financial impacts on each market participant. Thus, congestion management is a critically important function for the IGO. In [13], FERC listed congestion management as one of the eight minimum functions of the RTO.

In actual operations, the congestion may be removed by the IGO through the acquisition of relief services from interested players connected to the network. The scheme for relieving congestion for multiple transaction networks must be nondiscriminatory and transparent to ensure comparable transmission services for each transaction. A desirable characteristic for the congestion management scheme is efficiency so as to minimize the costs of removing congestion. In particular, since the various transactions contribute to congestion and value the transmission usage differently, the ability of a congestion management scheme to determine each transaction's contribution to the congestion can then be explicitly taken into account in the congestion relief process. In addition, the determination of the transmission usage charges provides important information for market participants to allow them to evaluate possible transactions under consideration.

1.2 Review of the State of the Art

The introduction of the open access transmission regime has led to new challenges in the area of management and allocation of the unbundled services in multiple-transaction networks. In the previous VIU structure with generation, transmission, and distribution being typically owned and controlled by a single entity and the number of third party transactions being limited, these issues were either nonexistent or arose no major concerns. As the industry is moving towards a transaction-based paradigm in the competitive environment, management and allocation of the unbundled services are critical since transacting entities require *a priori* information to evaluate impacts of various transactions under consideration. Hence, the need to manage and allocate effectively these services is critical in order to facilitate a smoothly operating competitive electricity marketplace. It is the nonlinear and largely uncontrollable nature of power flows in transmission systems that make allocation and management of unbundled services in multiple transaction networks very difficult.

1.2.1 Real loss allocation and compensation

Real transmission losses represent a nontrivial cost element. One industry study's estimate of losses was that they represent about 4% of the total megawatt-hours generated [14]. Typically, losses were treated as an additional load in the system. Various approaches to evaluate and compensate for losses have been developed. A good survey of the schemes proposed can be found in [15].

While the total losses in the system may be evaluated with desired precision once the system state is known, the allocation of losses to each transaction on the system is far from trivial. In principle, the line flows, in the presence of multiple transactions, are measurable; however, the association of flow with each particular transaction involves a good degree of arbitrariness taking into account notions of marginality and the incremental nature of flows. Moreover, in the mathematical expression for the $|I|^2 r$ losses, the total system losses are a nonseparable function of all the transactions. As such, there is not a physically meaningful measurement scheme or a theoretically based evaluation methodology to determine the losses caused by each particular transaction.

Under various assumptions and approximations, several allocation schemes have been proposed. Kirschen et al. [16] introduced a basic assumption of proportionality which they used in a proposed scheme to determine the proportion of the active power flow in a transmission line contributed by each generator. They used this proportion of line use to evaluate the losses allocated to each generator. By making a similar proportionality assumption, another topology-based allocation scheme was developed by Bialek [17]. Both methods determine the share rather than the impact of a particular generator on each line flow, using assumptions that "can be neither proved nor disproved" [16]. A comparison of topology- and circuit-theory-based methods was given in [18]. These loss allocation schemes are not developed for a system with transactions since the objective is to allocate the losses to each generator. In a similar vein, the model and methodology proposed by the California ISO [19] uses a *generator meter multiplier* based on a penalty factor calculation for each generation bus. Wu and Varaiya in [20] developed a quadratic Taylor expansion of losses in terms of transactions at a given operating point. A novel allocation approach based on the Aumann-Shapley cost allocation [21] is proposed in [22]. None of the schemes cited above considers the possibility of negative loss allocation to a transaction arising in the presence of the so-called counter flows. On the other hand, using the argument that "it is always possible to compute the exact loss allocation corresponding to an infinitesimal bilateral transaction", Galiana and Phelan in [23] proposed a method that uses a set of governing differential equations to determine the allocation of losses among transactions. The method is dependent on the path of integration and may indeed produce negative loss allocation results.

Loss compensation at multiple buses using fixed, prespecified factors has been proposed in [24] and is used by the California ISO [19]. In the former, the so-called participation factors at selected locations are computed taking into consideration economic and reliability criteria. The factors in the latter are the *generation meter multipliers*. The objective of these schemes is to ensure that the total system losses are covered through the fixed pre-specified factors. The schemes do not focus on the amount of compensation to be provided by each individual transaction.

1.2.2 Allocation of reactive support requirements

Under the VIU structure, the provision of reactive power and voltage support was bundled with other services in supplying electricity to the end users. There was no need for separate costing/pricing of reactive support since the utility was virtually assured that it could recover the costs of each service through the rates charged for the bundled electricity. Reactive support requirement allocation was consequently not an issue. Under open access, however, reactive support requirement allocations among the transactions and the corresponding costing/pricing of the service constitute a key concern. Since reactive power cannot be transmitted efficiently over distances, any “market” for reactive power must be local. However, in reality there is very limited supply since production of reactive power by itself is unattractive to generators and the establishment of competitive markets in reactive support is questionable. An overview of the reactive support service’s key physical characteristics and dominant cost component can be found in [25]. While there are extensive studies that address a number of important engineering and economic issues of the reactive support service [26]-[36], the issue of reactive support allocation in a multiple-transaction system has received scant attention.

Analogous to the real losses, reactive support service constitutes an important component of the operating costs to the transaction participants. The complexities of the reactive support requirement allocation issue are due to the inability to associate the line flows with each particular transaction. Thus, there is no physical measurement nor a theoretical evaluation scheme to determine the amount of reactive support provided for each transaction. The mathematical expression for the reactive support requirements from generators is a nonseparable, nonlinear function of all the transactions in the system. What makes the allocation of reactive support requirements more complicated than the real loss allocation is the *local* and *heterogeneous* nature of the reactive support service. Reactive support needs to be provided by various generators throughout the system, and the system impacts and the costs of reactive support at various locations are different. Thus, the goal of the reactive support allocation is to determine the amount of reactive support requirements provided by each of the various generators to each transaction.

On a basis similar to the proportionality principle of [16], Kirschen and Strbac proposed a method to trace real and reactive power between generators and loads using real and imaginary currents [37]. The Aumann-Shapley methodology [21] was also used to determine the reactive support allocation [22]. This application does not exploit the physical characteristics of reactive support and the structure of the allocation problem.

1.2.3 Congestion management allocation

A number of congestion management mechanisms has appeared in the literature for different restructuring paradigms. Hogan proposed the contract network and nodal pricing approach using the spot pricing theory [38] for the so-called Poolco paradigm [39]. In the nodal pricing approach, congestion management is performed through a *centralized* optimal dispatch, while transmission charges are determined *ex post* and set to the nodal spot price differences. This scheme has been implemented in the PJM interconnection [7]. An excellent tutorial paper about Hogan's work can be found in [40]. It has been argued by Wu et al.in [41], however, that the claimed efficiency of the nodal pricing approach is based on unrealistic assumptions, that the implementation of the idealized nodal pricing paradigm is overly complex, and that it relies on a highly centralized market structure that inhibits competition and customer choice. Furthermore, [41] argued that the *ex post* determination of the transmission prices is a severe obstacle to efficient bilateral transactions. Chao and Peck proposed in [42] an alternative to nodal pricing, which they claimed to be able to achieve in equilibrium the same outcome as that in [39]. It is based on parallel markets for link-based transmission capacity rights and energy trading under a set of trading rules imposed by the IGO. The trading rules specify the transmission capacity rights required to support bilateral transactions between any two buses and are adjusted continuously to reflect changing system conditions. On the basis of the so-called *coordinated multilateral trade* framework, Wu and Varaiya developed an operating paradigm in which the decision mechanisms regarding economics and reliability (security) of system operation are separate [20]. Economic decisions are carried out by private multilateral trades among generators and consumers. The function of reliability is coordinated through the IGO who provides publicly accessible data upon which generators and consumers determine profitable trades that meet the secure transmission loading limits. They proved that any sequence of such coordinated private multilateral trades leads to efficient operations, i.e., maximizes social welfare. The decentralization in these two approaches and their reliance on market forces rather than on a central planning paradigm is attractive [20] [42]. However, their implementation would require the availability of a highly sophisticated market making use of advanced information technology.

A number of congestion management schemes based on optimal power flow (OPF) in a multiple-transaction system have been proposed. An approach to relieving congestion using the minimum total modification to the desired transactions was presented in [43]. A variant of this least modification approach [44] used a weighting scheme with the weights being the surcharges paid by the transactions for transmission usage in the congestion-relieved network. The higher surcharge a transaction is willing to pay, the smaller the change that is made to it. In both [43] and [44], the decision variables of the IGO are the MW modifications to the transactions. The congestion management scheme for the California ISO developed in [45] aims to relieve the network of interzonal congestion using the adjustment offers of the schedule coordinators. The so-called scheduling coordinators are bilateral transaction managers who have a portfolio of loads and resources which are kept in balance for each period [6]. The congestion management relief objective is to maximize the value of the limited transfer capability measured by the offers. Every entity scheduling flow on a congested path is charged at the marginal price of the transfer capacity of the path which is determined by the congestion relief scheme. An important feature of this congestion management scheme is the enforcement of the *separation of markets* constraint to ensure that the IGO does not create new transactions that the schedule coordinators did not initiate on their own. A similar adjustment-auction-based scheme proposed in [46] differs from [45] in that the *separation of the markets* constraint on each schedule coordinator is not introduced. A further difference is that while transactions are charged a uniform price for their actual usage in [45], the scheme in [46] proposed to compute charges to recover the total congestion costs incurred by the IGO using so-called *constraint allocation factors* and *load allocation factors* for each schedule coordinator. Other congestion management schemes have been implemented for the various new market structures throughout the world. A unified framework for the different schemes in use, including the California ISO [6], the PJM ISO [7], the NordPool [47], and the England and Wales Power Pool [48], was constructed in [49] and used to perform a side-by-side comparison.

All the references cited above have addressed the issue of congestion management in the forward markets. For the real time congestion management, NERC has developed a specific transmission loading relief (TLR) protocol [10] for the Eastern Interconnection for curtailing transactions to maintain system reliability/security. While it has been used successfully to mitigate overloads on many occasions over the past few years, it is a purely physical load-relief method in which the economic issues associated with congestion management are completely ignored. The shortcomings of the procedure were discussed in [50] and FERC also recognized that such administrative curtailment procedures may be inappropriate in the competitive environment [13]

1.3 Thesis Scope and Contributions

In this section, we describe the scope of the thesis and briefly summarize the key contributions of the thesis.

The objective of the work reported in the thesis is to develop allocation and management mechanisms for unbundled services in multiple-transaction networks that are physically appropriate and provide meaningful and reasonable results. The three unbundled services treated in the thesis are transmission real power losses, reactive support requirements, and congestion management.

A common feature of all the allocation mechanisms developed in the thesis is that they are physical-flow-based and explicitly take into account the interaction with the networks; they are not economically based allocations since the economic efficiency goals are not incorporated in the determination of the allocation. We bring in economic efficiency considerations in the subsequent stage where we address the least price strategies for such tasks as the loss compensation procedures and the least-cost congestion relief scheme. The treatment of the pricing of the reactive support requirement allocations is not addressed in the thesis and is left as a future research topic.

In Chapter 2, we develop a general multiple-transaction network framework. In this framework, multiple transactions using the transmission network simultaneously are given and explicitly represented. The framework serves as the basis for formulating the three services. In Chapters 3, 4, and 5, we use the framework constructed in the previous chapter to develop physical-flow-based schemes to determine for individual transactions

- real power loss allocation and compensation,
- reactive support requirement allocation, and
- congestion management

Chapter 6 summarizes the key results and presents some directions for future research.

We use the multiple-transaction network framework described in Chapter 2 to formulate the power flows explicitly in terms of the amounts of transactions in the system. Under the conventional DC power flow assumptions, we develop a physical-flow-based allocation expression of the total system losses. Using sensitivity information, we develop a scheme that allocates the losses in an appropriate way that is physically reasonable. The scheme deals effectively with counter flows resulting when certain transactions are present in the network.

We make use of this allocation scheme to develop flexible and efficient loss compensation procedures in a multiple transaction network. We develop the equivalent loss compensation concept and apply it to such a network to develop the basis for compensating losses at any bus in the system. In our work, we construct a loss compensation procedure that provides each transaction with the choice of the compensation buses and the respective amounts of compensation. The compensation scheme allows transactions more choices for covering the losses than the scheme proposed in [13], in which each transaction in a multilateral trade framework can choose either the injection or the withdrawal bus for compensation. We also develop a procedure to allow transactions to have their loss allocation covered by the IGO. The IGO may provide its loss compensation as a value-added service to transmission customers so as to take advantage of the information the IGO has available and to take into consideration grid constraints. The IGO may acquire such loss compensation by determining the least-price solution for the acquisition of the required energy. The IGO's least-price loss compensation is formulated as a linear program. The two compensation mechanisms may coexist and any physically feasible combination of them is possible.

In Chapter 4, we present a new physical-flow-based mechanism for allocating the reactive power support requirements provided by generators in multiple-transaction networks. The allocatable reactive support requirements are defined with respect to the support required for the network with no transactions in place. The requirements in the presence of the proposed transactions are formulated as the sum of two specific components - the voltage magnitude variation component and the voltage angle variation component. The formulation utilizes the multiple-transaction framework and makes use of certain simplifying approximations. The formulation leads to a natural allocation as a function of the amount of each transaction. The physical interpretation of each allocation as a sensitivity of the reactive output of a generator is discussed.

In Chapter 5, we develop a congestion management allocation scheme. This scheme provides the IGO with a physical-flow-based allocation mechanism to determine the contribution to the overload congestion made by each transaction. It also provides the IGO with a useful congestion relief tool in which the IGO acquires the congestion relief services to remove each transaction's congestion contribution in the most economic manner. The proposed scheme is general and can accommodate different market rule specifications. The scheme permits each transaction to make its own transmission usage decisions and provides the transaction with efficient price signals for this task.

The characteristics and capabilities of the various schemes developed in this thesis have been extensively tested, and representative results on a number of test systems, including the widely-used IEEE systems, are given for each scheme. The numerical results indicate that the proposed scheme behaves in a physically reasonable and intuitive way and provide good insights into the capability of these schemes to appropriately address allocation and management issues for the three unbundled services considered in this thesis.