Combined Pool/Bilateral Operation in Electricity Markets

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Abstract

This thesis develops a general combined pool/bilateral electricity market model that allows for the simultaneous dispatch of both pool and bilateral trades. The latter are usually negotiated privately among the generators and loads and result in long-term agreements of the order of days to months. The bilateral contracts can be firm or non-firm but in all cases they stand for physical rather than financial obligations to generate a certain amount of power at some bus and to consume it at some other specified point in the power network. The power consumed by the loads that does not come from bilateral contracts is supplied by the pool generation, and is traded in the so-called spot markets whose time horizons can range from a day to as close as one hour.

In this combined market model, all ancillary services including transmission losses and congestion management are supplied by the pool. The market clearing process identifying the scheduled generation levels and the nodal electricity prices (also known as locational marginal prices) is defined by the solution of an optimal power flow which minimizes the total offered generation cost plus any curtailment or non-curtailment costs. This optimization, which is performed centrally by a system operator, simultaneously satisfies the power balance at all the network buses while respecting the power flow limits in all lines including transmission losses. In particular, the market clearing process takes into conisderation generation limits imposed by the bilateral contracts, a constraint which as this thesis demonstrates can have a profound impact on the market performance.

The performance of the combined pool/bilateral market is evaluated both technically and financially. The technical performance of a specific market is measured in terms of the pool and bilateral generation levels, by the degree of transmission congestion and by the transmission losses. The financial performance of individual market participants is based on the nodal prices, power transfer rates, as well as on the revenues and expenditures of both generators and loads.

Simulation results indicate that careful coordination of the pool and bilateral trades is essential as certain mixes can force out of merit generator operation, unnecessary

transmission congestion, lower generation revenues, and higher consumer payments. This is particularly so if the bilateral contracts are firm.

In order to lessen the consequences of inefficient pool/bilateral mixes, a variation of the combined pool/bilateral market is also examined under which the participants may submit curtailment offers for their firm contracts and non-curtailment bids for their non-firm contracts. The market clearing procedure in this case determines the levels of generation, the nodal prices, as well as the levels of contract curtailment.

Finally, the Aumann–Shapley unbundling procedure is applied to the combined pool/bilateral model with firm contracts. This enables the decomposition of the generation levels into three different service components, namely pool generation, bilateral generation, as well as a generation term supplying ancillary services attributed to the bilateral trades. The unbundling procedure also calculates the corresponding costs associated with these "unbundled" services and allocates them among the different market participants. This service and cost unbundling process is then implemented into a Pay-as-Bid pricing mechanism and compared with the conventional marginal pricing.

Résumé

Cette dissertation propose une structure pour un marché d'énergie électrique permettant l'ordonnancement simultané de transactions bilatérales et de transactions anonymes à travers d'un pool centralisé. Les contrats bilatéraux sont normalement transigés directement entre les producteurs et les consommateurs, et résultent en des accords à long terme allant de quelques jours à quelques mois. Ces contrats peuvent être fermes ou non. Toutefois, ils sont des obligations physiques de produire ou de consommer une quantité donnée d'énergie à un point donné du réseau plutôt que de simples obligations financières. L'énergie consommée ne provenant pas des contrats bilatéraux préétablis est fournie par la production mise en commun par le pool. L'horizon du processus d'ordonnancement du pool centralisé varie d'un jour à une heure.

À l'intérieur de ce modèle de marché mixte pool/bilatéral, tous les services auxiliaires incluant les pertes et la gestion de la congestion du réseau de transport sont fournis par le pool. Le mécanisme de résolution du marché utilise un algorithme d'écoulement de puissance optimal qui minimise le coût total de la production ordonnancée par le pool en plus des charges reliées au contingentement ou non-contingentement des contrats bilatéraux. Cet algorithme identifie l'ordonnancement optimal de la production en plus des prix de l'énergie électrique à chacune des barres du réseau. L'algorithme d'optimisation, exécuté de manière centralisée, se doit de satisfaire simultanément l'équilibre entre la puissance consommée et injectée à chacune des barres du réseau tout en respectant les limites de transit de toutes les lignes de transport. En particulier, l'algorithme prend en considération les restrictions de production imposées par les contrats bilatéraux. On démontre que ces restrictions peuvent avoir un impact significatif sur la performance du marché.

L'efficacité de ce modèle de marché mixte est évaluée sous un angle technique et financier. L'efficience technique d'un marché donné est mesurée selon les niveaux de production ordonnancés par le pool et par les contrats bilatéraux, par le degré de congestion du réseau et par le niveau des pertes sur le réseau. Le rendement financier des participants du marché se base sur les prix de l'énergie observés à chacune des barres du réseau, du taux

d'échanges de puissance, en plus des revenus et des dépenses des consommateurs et des producteurs.

On démontre, à l'aide des résultats de simulations numériques, que la coordination du pool et des échanges bilatéraux est essentielle car certains ordonnancements entraînent l'opération non économique des unités de production, un degré de congestion du réseau très élevé, des revenus moindres pour les producteurs, et de plus grandes dépenses pour les consommateurs. Ces phénomènes sont particulièrement accrus lorsque les contrats bilatéraux sont fermes.

Afin de diminuer les conséquences de l'inefficacité de certains ordonnancements, une variante du modèle de marché mixte bilatéral/pool est examinée. Cette variante permet aux participants de soumettre des offres de contingentement de leurs contrats fermes et des offres de non-contingentement pour leurs contrats non fermes. La procédure de résolution du marché dans ce cas détermine les niveaux de production, les prix à chacune des barres en plus des niveaux de contingentement des différents contrats.

Finalement, la procédure de décomposition d'Aumann-Shapley est utilisée pour le modèle de marché mixte pool/bilatéral avec des contrats fermes. Celle-ci permet la décomposition des niveaux de production en trois composantes de service différentes, c'est-à-dire la production associée au pool, la production associée aux contrats bilatéraux et la production associée aux pertes et à la gestion de la congestion sur le réseau. Cette procédure calcule en plus les coûts correspondants à chacun des services et les attribue aux participants du marché. Ce processus de décomposition des coûts et des services est ensuite appliqué à un marché utilisant un mécanisme de compensation *selon l'offre*. Celui-ci est comparé avec la même procédure appliquée lorsque la compensation se fait selon le coût marginal.

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$\mathbf{P}_d$ - vector of total bus demands

$\mathbf{P}_d^p$ - vector of pool demand components

$\mathbf{P}_d^b$ - vector of bilateral demand components

P_{dj} - demand at bus j

P_{dj}^p - pool demand component at bus j

P_{dj}^b - bilateral demand component at bus j

$\mathbf{P}_g$ - vector of total generation outputs

$\mathbf{P}_g^p$ - vector of pool generation components

$\mathbf{P}_g^b$ - vector of bilateral generation components

P_{gi} - generation output at bus i

P_{gi}^p - pool generation component at bus i

P_{gi}^{pcl} - generation component at bus i for the supply of pool demands and ancillary services associated with the pool demand

P_{gi}^{bcl} - generation component at bus i for the supply of ancillary services associated with the bilateral trades

P_{gi}^{b} - bilateral generation component at bus i

$\mathbf{P}_{g}^{\max}$ - vector of upper generation limits

$\mathbf{P}_{g}^{\min}$ - vector of lower generation limits

$\mathbf{GD}$ - matrix of bilateral contracts

GD_{ij} - bilateral contract between generator i and load j

$\mathbf{GDF}$ - matrix of firm bilateral contracts

GDF_{ij} - firm bilateral contract between generator i and load j

$\widetilde{GDF}_{ij}^{des}$ - desired value bilateral contract for which generator i and load j wish to acquire firm status

GDF_{ij}^{app} - pre-approved value of firm bilateral contract for which generator i and load j acquired firm status form the System Operator

$\mathbf{GDNF}$ - matrix of non-firm bilateral contracts

$GDNF_{ij}$ - non-firm bilateral contract between generator i and load j

$\mathbf{e}$ - vector of ones of dimension $1 \times n$

$\mathbf{P}_{f}$ - vector of line flows

$\mathbf{P}_{f}^{\max}$ - vector of line-flow limits

$\Theta_{gi}(P_{gi})$ - offer of generator i for trading in the pool market

$I\Theta_{i}$ - incremental cost based on the offer of generator i, Θ_{gi}

$C_{gi}(P_{gi})$ - true cost curve of generator i

$\Omega_{dj}(P_{dj})$ - bid of load j submitted to the pool

$B_{dj}(P_{dj})$ - benefit function of load j

bf_{ij}^{app} - rate paid by firm bilateral contract GDF_{ij} to the System Operator to acquire firm bilateral status

bf_{ij} - curtailment offer of firm bilateral contract GDF_{ij}

bf_{gij} - curtailment offer of firm bilateral contract GDF_{ij} submitted by generator i

bf_{dij} - curtailment offer of firm bilateral contract GDF_{ij} submitted by load j

bnf_{ij} - curtailment offer of firm bilateral contract $GDNF_{ij}$

bnf_{gij} - non-curtailment offer of non-firm bilateral contract $GDNF_{ij}$ submitted by generator i

bnf_{dij} - non-curtailment offer of non-firm bilateral contract $GDNF_{ij}$ submitted by load j

λ_i - nodal price or locational marginal price at bus i

π_{gi}^{p} - price charged by generator at bus i for pool generation

π_{dj}^{p} - price paid by load at bus j for pool demand

π_{ij}^{b} - pre-agreed bilateral price between generator i and load j for bilateral contract GD_{ij}

π_{ij}^{bf} - pre-agreed bilateral price between generator i and load j for firm bilateral contract GDF_{ij}

π_{ij}^{bnf} - pre-agreed bilateral price between generator i and load j for non-firm bilateral contract GD_{ij}

π_{ij}^{bcl} - power transfer price of bilateral contract GD_{ij}

$\hat{\pi}_{gij}^{b}$ - net bilateral price of bilateral contract GD_{ij} seen by generator i

$\hat{\pi}_{dij}^{b}$ - net bilateral price of bilateral contract GD_{ij} seen by load j

$\hat{\pi}^{f}_{gij}$ - net bilateral price of firm bilateral contract GDF_{ij} seen by generator i

$\hat{\pi}^{f}_{dij}$ - net bilateral price of firm bilateral contract GDF_{ij} seen by load j

$\hat{\pi}^{nf}_{gij}$ - net bilateral price of non-firm bilateral contract $GDNF_{ij}$ seen by generator i

$\hat{\pi}^{nf}_{dij}$ - net bilateral price of non-firm bilateral contract $GDNF_{ij}$ seen by load j

R_{gi} - total net revenue of generator i

R^{p}_{gi} - revenue of generator i for its total pool generation

R^{pcl}_{gi} - revenue of generator i for P^{pcl}_{gi} services that supply pool demand and the associated ancillary services

R^{pcl}_{gi} - revenue of generator i for P^{bcl}_{gi} services that supply ancillary services associated with bilateral trades

R^{b}_{gi} - revenue of generator i from its bilateral contracts

R^{f}_{gi} - revenue of generator i from the System Operator for the curtailment of its firm contracts

E^{bcl}_{gi} - power transfer payments of generator i for its bilateral contracts

E^{nf}_{gi} - payment of generator i for its scheduled non-firm contracts

$\tilde{E}^{b}_{dj}$ - net bilateral revenue of generator i

pr_{gi} - profit of generator i

E_{dj} - total net expenditure of load j

E^{p}_{dj} - expenditure of load j for its pool demand

E^{b}_{dj} - expenditure of load j from its bilateral contracts

R^f_{dj} - revenue of load j from the System Operator for the curtailment of its firm contracts

E^{bcl}_{dj} - power transfer payments of load j for its bilateral contracts

E^{nf}_{dj} - expenditure of load j for its scheduled non-firm contracts

$\tilde{E}^b_{dj}$ - net bilateral expenditure of load j

pr_{dj} - profit of load j

E^{bcl}_{ij} - power transfer payment of bilateral contract GD_{ij}

Ef^{bcl}_{ij} - power transfer payment of firm bilateral contract GDF_{ij}

Enf^{bcl}_{ij} - power transfer payment of non-firm bilateral contract $GDNF_{ij}$

MS - merchandising surplus of the System Operator

Θ^{pcl}_{gi} - unbundled cost of generator i associated with P^{pcl}_{gi} component

Θ^{bcl}_{gi} - unbundled cost of generator i associated with P^{bcl}_{gi} component

Θ^b_{gi} - unbundled cost of generator i associated with bilateral P^b_{gi} component

$\tilde{\Theta}^{bcl}_{ij}$ - unbundled cost component allocated to bilateral contract GD_{ij}, for the supply of its associated ancillary services

Θ^{bcl}_{ij} - unbundled cost component allocated to bilateral contract GD_{ij}, for the supply of its associated losses and congestion management

$\Theta^{\max}_{ij}$ - unbundled cost component allocated to bilateral contract GD_{ij}, due to effects of generator i operating at it maximum output level

Θ^b_{ij} - unbundled cost component allocated to the bilateral contract between generator i and load j for the supply of GD_{ij}

Θ_{dj}^{b} - unbundled cost component allocated to load j for its bilateral contracts

Θ_{dj}^{p} - unbundled cost component allocated to load j for the supply of its pool demand, P_{dj}^{p}, plus associated ancillary services

Chapter 1.

Introduction

1.1 Background

In the past, most electric utilities operated as vertically integrated systems, having complete control over power production, transmission and distribution in the geographic area they served, and were therefore considered as monopolies. A main goal of these utilities was to maintain reliable and economical operation of its network. All decisions and actions to support such operation were coordinated by the control centers. In addition, utilities were the sole owners of the transmission network, generation capacity and all other resources necessary to meet their goal. Customers paid a single tariff that reflected all associated costs plus a reasonable rate of return that was controlled by a government regulatory body.

The move to restructure the electricity industry over the past decade or so however initiated a radically new philosophy in power system operation. Utilities were obliged to separate into independently operated generation, transmission and distribution companies, while introducing competition and separate pricing for various services, a process known as unbundling. In addition, power system restructuring brought in the notion of open and equal access to the network by all competing agents.

The shift towards the deregulated operation was successful in some countries and parts of the US however in other cases it resulted in market failures [1, 2]. This was due mainly to the unique characteristics of electricity compared to other types of commodities, primarily the need to satisfy Kirchhoff's and Ohm's laws and to match supply and demand instantaneously. This highlights the fact that finding appropriate electricity market models is not an easy task and requires closer cooperation between power system engineers and economists.

For the supply of real power, two main market models have emerged: (1) *pool trading* which is carried out through a centrally operated entity that determines generation levels and prices based on submitted generation offers and load bids, and (2) *bilateral trades* defined by privately negotiated bilateral contracts that can be either physical or financial obligations. Both models require a central system operator whose task is in one case to calculate the pool dispatch based on the submitted offers and in the other to approve and adjust the bilateral trades. In addition, the system operator ensures that line flows are within limits so as to maintain both reliable and economic system operation.

Both electricity market models allow for the trading of separate services (ancillary services) needed to support power system operation. For instance, active power generation can be subdivided into components that cover demand, network losses, as well as fast and slow reserve. The supply of reactive power and voltage support has also been considered by some as separately-priced tradable commodities. One difficult question here is how to price and cost the various services as well as how to coordinate them.

Although open access to the transmission network allowed the various market participants (generators, loads and marketers) to freely choose their trading partners, this can also lead to congested system operation, a condition which may backfire by rendering a trade unprofitable after considering transmission costs. This drawback can occur in transmission networks that were built in the "regulated era" and were designed for certain patterns of power flows. Under the new trading rules these flows can change, causing a network to operate under conditions for which it was not intended, and which can lead to network congestion.

To correct this problem and improve system operation, different solutions are possible, both financial and technical. Under the first approach a price is placed on network line overuse to send adequate incentives and discourage market participants from causing congestion. The technical approach seeks to improve network capability by installing additional lines or equipment that can enhance the control of power flows.

1.2 Motivating factors and topics of thesis

Prior to this research, most of the published results dealt with either pool or bilateral electricity market models, with relatively little work reported on a general market model that allowed for combined simultaneous dispatch of both pool and bilateral trades. This thesis therefore investigates such a combined power system operation when all ancillary services as well as congestion management is run by the pool.

In such a combined market, generators may sell part of their power to the consumers through privately negotiated bilateral contracts, which can be firm or non-firm. They may also sell the excess generation output to the pool by submitting offers in the form of curves of $/h versus MW produced. The pool then dispatches generation according to these offers to meet any remaining unserved load, to supply the necessary transmission losses, and to carry out congestion management if needed.

Unless carefully coordinated, certain mixes of pool trades and bilateral contracts can interact so as to impair significantly the technical performance of the power system as well as the financial performance of individual generators and consumers. Particular attention must be paid to firm bilateral contracts which can not only force the pool to operate out of merit but which can also lead to unnecessary transmission congestion, to low generation revenues, and to high consumer payments.

To analyze these effects, an electricity market model is developed for this thesis based on the optimal power flow. Various technical and financial performance measures (revenues and expenditures) are then defined from the perspectives of the system, as well as individual generators and loads. Through these measures, the combined pool-bilateral market model is then examined under two pricing schemes:

- Locational Marginal Pricing (LMP)
- "Pay-As-Bid" Pricing (PAB)

In addition, the market model under LMP method is extended to include firm and non-firm bilateral contracts with curtailment options. These are useful variations of the market rules which can avert overly congested operation due to poor planning of the bilateral trades.

1.3 Claim of Originality

To the best knowledge of the author, the following can be considered as original contributions to research:

1. Application of the combined pool/bilateral model with simultaneous trades, where bilateral contracts are considered physical. This is a one-step procedure that dispatches the pool in combination with the privately negotiated bilateral contracts while minimizing cost and accounting for both losses and congestion.
2. Investigation of the influence on system operation of the relative levels of bilateral versus pool trades from the points of view of technical and financial performance. This is carried out from the perspective of individual generators and loads.
3. Derivation and analysis of additional financial measures that allow market participants to evaluate the relative profitability of each component of its chosen pool/bilateral mix. This information can be used by agents to plan their future participation mix in the combined market.
4. Extension of the original combined pool/bilateral model to include curtailment bidding of firm contracts, so as to allow for better coordination of bilateral trades, to enhance congestion management strategies, and to reduce congestion costs. These additional features could also be used by bilateral parties to curtail contracts with non-profitable pre-negotiated prices.
5. Addition of non-firm contracts with non-curtailment bids to the combined pool/bilateral model. This type of trades also improves pool/bilateral coordination and congestion management. Here, traders with non-firm bilateral contracts may offer to pay in order to improve its chances of non-curtailment.

6. Application of the combined pool/bilateral model in the algorithm that allows for service and cost unbundling of generation outputs. Namely, under the combined model, it is possible to distinguish three services provided by the generators and received by the consumers and the bilateral parties.
7. Unbundling of the generator outputs into three components: pool supply (including required ancillary services), bilateral supply, and ancillary services allocated to the bilateral contracts. A similar unbundling is also carried out for the generation cost and to the cost component allocated to the loads and the parties involved in bilateral trading. The unbundling algorithm is based on the Aumann-Shapley cost sharing pricing method [3, 4].
8. Application of the previous algorithm to Pay-as-Bid pricing of the pool operation. So far, the Pay-as-Bid method was used only for bilateral contracts, however the possibility to unbundle services and costs and allocate these costs among the various market participant allows for its application to pool operation as well.

1.4 Thesis outline

The nature of different electricity market structures and rules are reviewed in Chapter 2. Some aspects of existing research on current market models, both from the perspective of generation competition and transmission pricing, are examined. This chapter also summarizes various types of ancillary services and how these could be traded under different market models. Finally, a comparison of existing pool and bilateral electricity markets is presented.

The combined pool/bilateral model proposed in this thesis is presented in Chapter 3. The market structure of this combined model is defined together with trading options and rules for the different market participants. Then, the mathematical framework of the dispatching procedure is defined, together with various generation and load components.

Furthermore, the pricing of these components is explained and various financial performance measures are defined. These include a range of generator and load revenues and expenditures, as well as the merchandising surplus of the network.

Application of the Locational Marginal Pricing approach for the mixed pool/bilateral operation is illustrated in Chapter 4. Numerical results under the assumption of firm bilateral contracts highlight the importance of good bilateral planning to avoid unnecessary congestion and out of merit operation. In order to add the necessary coordination between the pool and bilateral trades and ultimately enhance overall system operation, the original model is modified to include curtailment offers of firm contracts. The model is also extended to allow non-firm bilateral contracts with non-curtailment bids. This new framework is derived and tested numerically in Chapter 5.

Finally, in Chapter 6, the combined pool/bilateral model is implemented to calculate the various generation and load services and associated costs. Then these unbundled variables are implemented to define financial performance measures under the Pay-As-Bid pricing scheme. The values of these measures are then compared with results obtained under Locational Marginal Pricing.

Final remarks on the combined pool/bilateral electricity market model and its applications are given in Chapter 7, together with some proposed extensions of this research.

Chapter 2.

Models and Rules in Electricity Markets

2.1 Restructuring of the Electricity Industry

One of the aims behind the restructuring of the electricity industry was to allow market forces to play a greater role in the operation and planning of power systems. The basic expectations of such a change were that efficiency would increase and that electricity prices would decline without compromising reliability. This ideal vision assumed that the restructuring process would stimulate the development of new technology that would replace old inefficient equipment allowing investors to earn significant profits, notwithstanding the lower electricity rates.

A first step in the restructuring process consisted of unbundling the traditional vertically integrated utilities into separate commercial units that operated independently of each other, although not necessarily separately owned. These units were generation, transmission and distribution. In addition, the security of the system operation was usually assigned to an independent entity here called the system operator (SO). The economic operation of a power system was managed by a market operator responsible for balancing supply and demand and for setting prices. Several different forms of electricity markets and operators have been developed, some of which will be discussed in greater detail below.

In addition, the traditional captive relation between customers and the integrated utilities was removed, allowing each load the option to choose a supplier willing to offer better services or a better price. Independent Power Producers (IPP's) were encouraged to enter the market and increase competition. In some cases, existing large generating companies were divested into smaller units through legislation [5]. Furthermore, all market participants were given open access to the transmission network, so as to freely engage in electricity trades between any two points in the network, subject only to the laws of physics and to the capacity of the transmission lines.

These structural changes completely transformed the electricity industry. Generation companies and load supplying companies became market participants looking to sell or buy electricity. Furthermore, attracted by business possibilities, various other market players started to appear, mainly traders who bought and sold power. One trend that stood out was to model electricity markets so that in structure they resembled traditional markets for other goods. The problem with this, however, was that electricity differs from other commodities in a number of significant ways:

- The need to instantaneously balance generation and demand;
- No means to effectively store large amounts of electricity;
- Transmission being a natural monopoly;
- Severe limitations in the ability to control the flow of electricity.

These factors make electricity markets more complex to run and call for tighter central coordination. The first feature requires real-time balancing between generation and demand at every bus, on a second to second basis, while maintaining system frequency and bus voltages within tight limits. The lack of storage means that prices are more volatile and sensitive to market power[1].

The natural monopoly of transmission and the inability to effectively control the flow of electricity distorts perfect market competition. This behaviour does not occur in most other markets. There, the consequences are typically not as grave as in electricity markets where inadequate transmission flow-control can cause unreliable operation and system failure.

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[1] *Market power* means that some participants are in a position to influence the market outcome, and thus benefit at the expense of others.

The above mentioned features call for particular attention when defining market models and rules which should be transparent, easy to implement, and still lead to efficient electricity markets [6].

Figure 2-1 shows a schematic representation of the restructured electricity industry divided into its various components [7, 8]:

- Generation side: generating companies (G) and power marketers (PM);
- Demand side: retail (R) and distribution (D) service providers;
- Transmission and Trading Coordination sector: power exchanges (PX), transmission owners (TO), system operator (SO), ancillary service providers (AS), and scheduling coordinators (SC).

Although each of these components has a specific and important role[2] in the market, it is not necessary for all of them to exist as separate entities. Depending on the market model, the tasks of one component can be assigned and performed by another. For instance, in a centralized market model the SO runs the market and therefore takes over the responsibilities of the Scheduling Coordinators and the Power Exchange. On the other hand, when the SO is not involved in trading, the SC and PX are of great importance for market functioning, and have to be in place. Figure 2-1 also indicates the central role of the SO, which is generally responsible for the tight coordination of all other market entities.

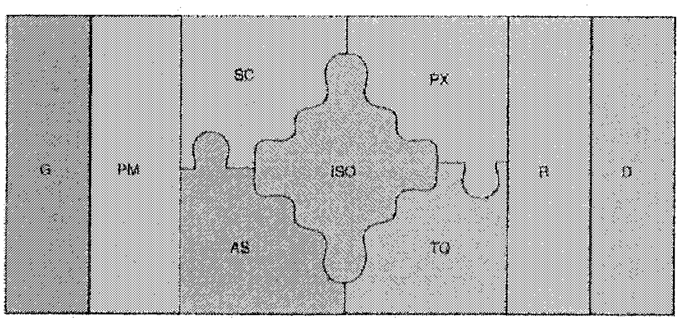

Figure 2-1. Structural components of electricity markets [8]

[2] An extensive review on the roles of each of theses segments is given in [8]

After a major debate regarding the role of the SO two major market concepts evolved: one with a strong SO and the other with a SO having fewer centralized responsibilities. In the first model the SO is directly involved in the trading process and runs the electricity market. This is the so-called *MaxISO* model, generally referred to as the *Pool* (or *Poolco*) model. The second type of SO favors more decentralization such as bilateral contracts among market participants and is known as the *MinISO* or *Bilateral* model. Both market models have their merits and shortcomings, and their application has been extensively discussed and analyzed in the literature [9-21]. Notwithstanding the poor experience in California that favoured the decentralized model, it cannot be stated with certainty that either the pool or the bilateral model is the definite best market choice.

2.2 Pricing Methods

An important component of electricity market design is the pricing method which defines tariffs for electricity as well as for the various ancillary services [22]. Pricing plays a central role in the market, as it sends monetary signals on the value of the resources, signals that strongly influence future investments in the system infrastructure. In addition, from the perspective of the consumer, the price of electricity must be competitive. To meet these goals, a well-designed pricing mechanism has to address both the problem of short- and long-run efficient market operation.

The difficulty with electricity is that its previously mentioned characteristics make electricity markets inherently imperfect, with the two most notable imperfections being the exercise of market power by generators, and the congestion of the transmission network. Market design, with its pricing schemes and rules, needs to tackle these problems, and discourage market participants from behavior that triggers such imperfections [6].

Generally, two main pricing mechanisms have been applied in electricity markets. The first approach is based on *marginal pricing* theory, where the price equals the short-run marginal cost, one of the seveal general pricing polices recommended for a regulated natural monopoly [23], also suggested by Vickrey [24, 25].

The second pricing mechanism is the non-uniform "*Pay-as-Bid*" pricing, where each participant is paid according to its submitted offer or bid. This payment is not affected by the offers of other market players, which contrasts with the marginal approach where the price is determined by the highest offer of a scheduled generator.

The application of these two pricing methods for the various services traded in electricity markets is discussed next.

2.2.1 Service unbundling and pricing

The primary product traded between generators and loads is active power. However, to ensure secure system operation, one can define various unbundled services which in principle could be traded separately and would require separate pricing mechanisms. Ancillary services include generation of losses and real-time load following, reactive power generation and voltage regulation, as well as spinning reserve [7]. Under the MaxISO, the ancillary services are charged through prices that embed all services, however under the MinISO model, separate markets and prices can be set up for the each service.

Generation trading and pricing

Opening the generation side to competition was one of the foundations of the restructuring of the electricity industry. Generation pricing was therefore a significant factor in market design. The type of the pricing used is closely tied to whether centralized (spot or pool) or bilateral trading is employed.

Centralized trades

Spot trades are conducted through a centrally run market, such as a pool managed by a SO. Trading in these markets is usually done on a short-term basis, e.g., day-ahead or hour-ahead.

Two Pricing Techniques: Marginal and Pay-as-Bid

Typically, the pricing mechanism of centralized trading is founded on the marginal pricing method. Generators compete to supply demand by submitting offers in the form of curves of $/h versus MW output, as well as start-up costs and their operating constraints and availability. Based on these offers, as well as the load purchase bids, the market operator determines the generation dispatch that maximizes social welfare[3], subject to transmission and other system constraints. There are two main variations of marginal pricing in electricity markets:

- system marginal pricing;
- locational marginal pricing.

Under system marginal pricing [26, 27], the generator offers are stacked in a merit order, and the clearing price is defined by the intersection of this curve with the cumulative load curve, as illustrated in Figure 2-2. The market clearing price, or Spot Market Price (SMP), normally calculated on an hourly or half-hourly basis, is then applied to all generators uniformly, regardless of their offer or their location.

As the SMP does not explicitly take into consideration transmission constraints, various rules have been developed to address the transmission congestion problem. For instance, the initial version of the England and Wales (E&W) pool market first calculated the merit order dispatch without transmission constraints. This dispatch was then revised under congested operation using heuristics under which re-dispatched generators were compensated by extra payments charged to the consumers in a pro-rata form. In the Scandinavian countries, the NordPool market is, in the case of congestion, split into zones whose supply is provided by separate generator offers. In that case, NordPool switches to a simplified Locational Marginal Pricing scheme.

Since the SMP method does not explicitly account for ancillary services, their pricing is usually in the form of uplifts, which are separate charges devised to cover the costs associated with the supply of such services. Again, these charges are passed on to the consumers usually as an extraordinary pro-rata charge.

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[3]Social welfare is defined as the difference between the total demand benefits and the total cost of generation.

Locational Marginal Pricing (LMP) is a more complex variation of marginal pricing. As in SMP, the market administrator collects generator offers and load bids, and calculates the optimal generation dispatch by maximizing social welfare. The difference here however is that the optimization is subject to various system constraints such as line loadability and voltage limits. In its most general form, this dispatch also includes the supply of losses and other ancillary services necessary to support system operation. LMP is normally applied in MaxISO models, in which case the System Operator runs an Optimal Power Flow (OPF) procedure that defines a price at each bus of the network [13, 28-30].

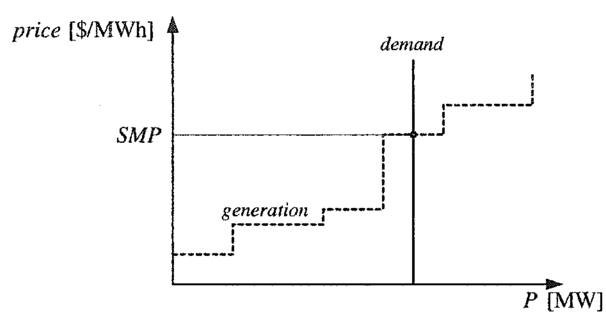

Figure 2-2. Spot Market Clearing Process

This form of dispatch can be based on a full AC OPF, but to simplify the numerical complexity, it is also possible to use an optimization procedure based on a linearized OPF. If, in addition, the simplified network model is lossless, a price difference among the buses will appear only for congested operation, however if the model also accounts for losses, locational prices will vary for each bus, even in the absence of congestion. One needs to be cautious about the application of simplified OPF models as such formulations can result in inefficiencies and cross-subsidies among competing agents [31, 32].

Besides marginal pricing, the Pay-as-Bid method could also be used in centralized operation. Scheduled generators would then be paid according to their offers, rather than based on the system marginal price or marginal nodal prices. This thesis presents a procedure to unbundle various generation services and calculate their associated costs for use in Pay-as-Bid pricing. Details of the proposed pricing mechanism are discussed in Chapter 6.

Difficulties Associated with Centralized Trading

Two important issues affecting the performance of pool trading are market power and price volatility.

- *Market Power*

Market power appears when, due to insufficient competition, some generators recognize that they are in a position to affect the market price and exploit this advantage to increase prices and earn extra profit. To make matters worse, as electricity demand is less responsive to prices than other commodities, demand-side market forces that would normally reduce demand and diminish the effects of generating market power are weaker.

Because of the nature of electricity in comparison with other commodities, generators have more opportunities to exercise market power than traders. As discussed in [33], generators can exploit market power not only by withholding their output (as with other more conventional commodities), but also by manipulating production so as to cause network congestion. Cardel et al. [33] have demonstrated these strategic interactions though examples, and showed the necessity of developing price incentives and other measures that will discourage such behavior. Similar analysis of congestion caused by an increase in production was performed in [34] for various auction mechanisms. The analysis demonstrated that the operation with separate market-clearing procedures is more vulnerable to strategic behavior by well-located market players than integrated pool auctions in which market clearing is carried out while simultaneously accounting for transmission constraints. Results from [35] argue in favor of transmission expansion to reduce market power.

One way to address the problem of market power is by designing adequate offer protocols. One example of how such protocols could be used in the England and Wales (E&W) pool market, the NordPool, and the Victoria Power Exchange in Australia is discussed in the survey on the design of pool market pricing auctions and mechanisms in [36]. Also, some argue that offers in discriminatory price auctions, like in the Pay-as-Bid method, would reduce market power and price volatility [37, 38]. Interestingly, others claim just the contrary, namely that Pay-as-Bid pricing can weaken competition and lead to inefficiency [39, 40]. This debate continues unresolved today. In any case, a change from marginal to Pay-as-Bid pricing or vice-versa would have a significant impact on generator offer strategies [37-39].

Other possibilities to restrain market power are through adequate transmission pricing or via bilateral trading as discussed later on in this chapter.

- Price Volatility

Because a balance between supply and demand has to be continuously maintained, and there is no practical way to effectively store electricity, its prices are more volatile than those of other commodities. Since the prices of centralized trades are known only after the calculation of the dispatch, this type of price is called *ex-post*. This characteristic exposes market participants to a greater price risk. To hedge against price uncertainty, generators and loads may choose to enter into bilateral trades that typically have a known pre-negotiated price valid over a longer time horizon than the spot-price.

Bilateral trades

Bilateral trades or contracts are directly negotiated agreements between market participants, for instance between a generator and a load. Such agreements can also be traded at forwards and futures markets. Bilateral agreements are not sold at a marginal price, but rather at a pre-negotiated rate, rendering this technique an *ex-ante* type of pricing. Each contract has its own price that depends only on the arrangement between the interested parties, and not on other trades. Therefore, bilateral agreements fall under the category of *Pay-as-Bid* (PAB) pricing scheme. In contrast to marginal pricing, since this price is pre-set, it is neither uncertain nor volatile. The drawback however is that a fixed bilateral price could be lower than the spot price, a condition which would be disadvantageous to the seller (generator) and advantageous to the buyer (load). Alternatively, if the bilateral price is higher than the spot price, an opposite effect takes place.

Types of bilateral contracts

Two major types of bilateral contracts can be distinguished:

(i) *Physical*;

(ii) *Financial*.

Physical contracts specify the parties that generate and consume the power agreed to in the contract, the buses of injection and consumption, as well as the amount of traded power. A selling generator has the obligation to produce power to supply at least all of its physical bilateral contracts, while a load is expected to consume at least all of its physical bilateral contracts.

Financial contracts, on the other hand, are agreements that specify only the amount and the price of the traded power, together with other trading conditions[4]. The points of injection and consumption may or may not be defined. Even if known, these points are not binding. This means that a selling side of the contract is free to appoint any market participant willing to supply the energy, while a buyer can also resell the contract further, and find another party to consume the power. Financial contracts may be resold at the market several times before the expiration date.

From the operational point of view, physical contracts directly affect generation dispatch since a generator has to produce at least the amount of its bilateral obligations. In addition, physical bilateral contracts may affect transmission congestion. Because of these influences on the overall system operation, the network usage resulting from each bilateral contract has to be approved by the System Operator before its actual scheduling. As defined by the North American Electric Reliability Council (NERC) [41] contracts could be *non-recallable*, also called *firm* or *non-interruptible*, and *recallable*, usually referred to as *non-firm* or *interruptible*. For a firm contract, the system operator confirms that the full amount of a approved power transfer could be scheduled, except in the case of an emergency. In order to withdraw from such a contract, or curtail it, parties may need not only each other's consent, but also the permission from the system operator.

[4] These conditions are of a financial nature allowing for a variety of contract arrangements, and do not pertain to system operation.

Alternatively, non-firm contracts are not guaranteed, and would be scheduled only as the operation conditions allow.

Financial contracts do not need to obtain any kind of advanced approval. A system operator does not even have to know about their existence. They are traded in the futures and forwards markets, without any power transfers actually being scheduled. To implement the trades arranged through financial contracts it is, however, necessary to transform them into settlements that firmly define the points of consumption, and to specify whether these loads are supplied bilaterally or through the pool.

If the financial agreement is to be fulfilled bilaterally, the parties involved transform their agreement into one or more physical contracts for which permission from the SO is required.

Contracts for Differences (CfD) are special financial contracts between a generator and a load in which they reach an agreement regarding the price and the amount of power traded, however only the centralized pool dispatch determines those generators that in fact supply the power. The trading partners essentially sell and buy their power through the pool, at the pool marginal price, and then in a separate financial transaction compensate each other for the difference between the pre-agreed and actual prices [22].

Financial Risk Management though Bilateral Contracts

As previously pointed out, the price of centrally traded electric power is volatile. These price fluctuations introduce financial uncertainties that market participants did not have to face in the era when utilities were regulated monopolies. In financial theory, a generally accepted strategy for a market player to hedge against spot price uncertainty is to engage in bilateral trades that offer more stable rates over time [42].

Hedging through futures contracts, as well as by production scheduling was investigated in [43] in the context of tradeoffs between profit and risk when evaluating bilateral trading. Application of interruptible forward contracts that allow supplier to disrupt a service is analyzed in [44] under integrated utility operation, while [45] further looks into the use of similar contracts that are interruptible from the demand side. The above mentioned research deals with hedging strategies for financial contracts for a single product (electricity). However, it is also possible to use an alternative *cross hedging* strategy where future contracts are negotiated in different markets [46], like natural gas or oil.

Besides a direct role in financial risk management, bilateral trading also affects the prices of centralized trades. Thus, producers may wish to use forward contracts to enhance their position in the spot market, even in the absence of uncertainty [47].

The original version of the England and Wales (E&W) pool and the current NordPool markets [48] show that there was indeed a link between bilateral and spot markets. Although theses two markets were quite different, it was observed that, as the number of bilateral contracts in E&W diminished, instances of spot price hikes became more frequent. On the other hand, increased bilateral trading in NoordPool market tended to reduce price volatility in the spot market. However, it was also observed that in the NordPool market, the average future prices were above spot prices at the time of delivery [49].

Transmission pricing and Congestion Management

A vital element of the electricity industry restructuring is the notion of open access to the transmission network, and this regardless of the generation market structure. Transmission access rules have to ensure that all market participants have equal access to the transmission grid as denial of such services or unequal access will infringe on free market operation and distort competition.

While opening the generation side to competition was possible, transmission and distribution networks are still considered natural monopolies. Thus, any tariff for the use of the network must be subject to regulation.

Because of losses and line flow congestion, the ability to trade can however be very much affected by the transmission network. In particular, under congestion, some markets participants could be denied transmission access for certain trades, because they would need to use lines already "consumed" by others. In microeconomic theory this is an *externality* problem, which arises when the *property rights*[5] are not well defined. The overuse of transmission lines (congestion) is an example of the overuse of *common*

[5] A property right is a right to decide how certain resources should be used.

goods[6] [50], which can occur when the network is inadequately managed and its access is inadequately priced.

General methods to correct the influence of externalities include:

- *internalization of externality costs* by those who are producing them;
- *taxation* and *quota policies;*
- setting up enforceable *property rights* and establishing additional markets for their trading.

Which of these techniques will give the best results depends on the particular market and commodity.

The System Operator, therefore, needs to establish transmission access rules and pricing which will support rational exploitation of the transmission grid, especially in the case of transmission scarcity. Furthermore, transmission charges have to properly compensate owners of existing lines and provide adequate signals for future investments. Some argue that policy makers are more concerned with congestion management than with improving transmission capacity [51]. In practice this latter mission has been overlooked, as transmission expansion has not kept pace with the market growth. The problem is that transmission expansion is not only expensive, but also involves environmental concerns, as the public opposition to new transmission corridors is quite substantial.

When designing a transmission pricing strategy the following principles should be respected [52]:

- recover the capital plus operation and maintenance costs and compensate the owners of existing transmission assets;
- encourage efficient network usage on a daily basis;
- signal the need for transmission and generation expansion to encourage efficient investments;
- be fair to all market players;

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[6] Common goods are those goods that do not have a well-defined owner who can control their use and exclude others from overusing them. A power network can be regarded as a common good. Technically, different parties could own transmission lines, but the SO controls their operation. Due to various factors, overuse (i.e. congestion) of the network may occur, causing market inefficiency.

- be transparent and understandable to users;
- be practically implementable.

Some of these requirements, however, are difficult to meet simultaneously. Thus, practical applications involve compromises, one of the most discussed being a tradeoff between short-term efficiency and simplicity [53]. An extensive survey on different transmission management methods has been presented in [54].

Many agree that pricing in electricity markets should account for the network and in particular power flow limits, an issue that has been extensively examined [55, 56]. In practice, two major paradigms have emerged:

- locational marginal pricing approach - mainly advocated by proponents of the MaxISO and pool trading,
- *Flowgate* approach - favored by proponents of MinISO and decentralized trading.

Major differences between these two approaches include how congestion is managed, questions regarding network representation, types of permitted bilateral trades and transmission rights, and actual transmission pricing for transactions (nodal vs. zonal and uniform). Both models agree that transmission rights[7] that allow their owner to access a portion of the transmission capability are necessary for bilateral trading[8].

One way to define a transmission right is to compute a so-called *point-to-point* transfer capability from point A to point B in the network, while another method is to determine a transmission capability for each link of the network [58].

A distinction can be made between financial vs. physical rights. The first entitles its holders to a financial compensation from anyone actually using the capacity, while the second guarantees a capacity reservation or scheduling priority.

Under locational marginal pricing [59, 60] the point-to-point transmission charge is equal to the location marginal price difference between the node of injection and the sink node. This payment is calculated ex-post so there is a certain risk associated with its

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[7] Transmission rights are property rights.

[8] Some analyses of transmission rights allocation, however, indicate that there could be instances where these rights would enhance the market power of some generators [57]. Recalling the analysis of strategic interactions [33, 35], this does not come as a surprise.

value. Traders can hedge against these unknown transmission payments by purchasing Financial Transmission Rights (FTRs) that guarantee their holder rights on transmission charges for acquired point-to-point reservations. FTRs are purchased from the SO, and could be traded since they do not affect generation dispatching. Tradable financial rights shield the parties in bilateral contracts from potentially high congestion costs, while those who have not secured such insurance remain vulnerable, since their transmission expenses are based on nodal price differences.

In the Flowgate approach, market participants have to obtain transmission rights across the lines they expect to use [58, 61] in order to gain full financial protection and scheduling priority. The rights are considered firm and can be initially acquired from a SO through auctions, however they can also be freely traded at a secondary market[9]. An important component of this method is to allocate transmission usage for each bilateral transaction. Usually, linear Power Transfer Distribution Factors (PTDFs) are used for this purpose however other methods are also proposed [62, 63].

Tradable flowgate link-based rights can be administrated in a separate market. The liquidity of the secondary transmission rights market is essential for efficient system operation.

In the California market, in the case of intra-zonal[10] congestion, an additional improvement step to adjust the requested schedule is performed [64-66]. Bilateral parties can submit increase and/or decrease offers that help the system operator modify requested trades. For lines that still operate at a limit, a financial settlement is based on zonal price differences.

Contract curtailment is also proposed as part of pool congestion management schemes [67, 68], where market participants compete for scheduling by submitting transmission offers. The pool solves a coordination problem by minimizing deviations from the requested values.

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[9] This secondary market is considered a significant factor for bilateral trades.

[10] A congestion zone is defined as a portion of the grid where SO does not expects frequent line congestion. These areas are defined by the SO, based on previous experience. Lines that connect these zone could, however, be prone to congestion.

Other instances of congestion management include interruptible contracts for energy [69], allocation of congestion to each transaction depending on its contribution to a physical-flow [70]. And other variations from five different markets as discussed in [71].

In essence, the main debate is the centralized vs. decentralized administration of transmission rights. One school of thought argues in favor of tight centralized coordination, since it grants the most efficient system operation, and does not depend on the liquidity of the secondary transmission rights market. On the other hand, proponents of the decentralized approach favor bilateral trading, and clam that "passive" transmission rights[11] are not sufficiently market-oriented, and are prone to misuses by the SO and the transmission owners.

2.3 Two Electricity Market Concepts

All previously described structural and pricing concepts are applied in different electricity market models. An extensive survey of various market models in [72-74] covers the numerous design and rule issue previously discussed. The following sections outline their main characteristics as well as major differences.

First, two idealized "pure pool" and "pure bilateral" models, operationally feasible, are described [12]. Practically all market models have one of these two models as the predominant structure, but often include some elements of the other model as well.

Pure Pool Model

In a pure *Pool* market all markets participants are obliged to buy and sell power through the centralized pool run by the System Operator. There is no direct interaction between buyers and sellers, that is, there is no opportunity for direct physical of financial bilateral trades among market participants. Furthermore, the marginal pricing methods described above are typically applied.

[11] Oren refers to financial rights as "passive" rights.

Proponents of centralized operation assert that this tight coordination ensures efficient and secure system operation, because the SO has all the necessary information to determine the most economical dispatch. This type of operation was first put into operation in Chile and then in England and Wales.

Pure Bilateral Model

In contrast to mandatory pooling, the pure bilateral model is based solely on a set of physical and financial transactions, so that all transactions are negotiated between generators and consumers. Market clearing is defined by a set of balanced bilateral transactions. An independent System Operator is responsible for system operation, but manages only bilateral transaction already negotiated. Moreover, the SO will enter into bilateral contracts on its own, so as to secure the necessary ancillary services.

Predominantly Pool Concept with Financial Bilateral Contracts

This model, lately also referred to as Integrated [72, 75] evolved from the pure pool model, when market participants felt a need to hedge against spot price volatility and uncertainty, and started to enter into financial Contracts for Differences (CfD). Because of the CfD structure, the involved parties did not need approval from the SO or any other body, and it was a convenient way to reduce market risk.

In addition, predominantly pool-based markets like PJM, New Zealand and Australia [76] have instigated these bilateral trades. The SO has still maintained its central role in the system operation and performes overall optimization subject to generation, transmission and other system constraints.

Proponents of this model argue that the level of efficiency achieved through a centralized market can hardly be matched or exceeded by alternative decentralized models [18], even asserting that this is the model that "should fit all" [77].

It is interesting to note, though, that in March 2001 a completely different model replaced one of the most renowned pool type markets, namely the market of England and Wales. The *New Electricity Trading Agreements* (NETA) is based on bilateral trading and a Pay-as-Bid pricing mechanism in the balancing market [39, 78]. The primary objective of this change was to curb market power of generators and reduce prices. So far, prices have gone down, but it is still early to draw some definite conclusions regarding the operation of this new structure.

Also, recently some markets, like PJM, have started to allow generating units to self-schedule their output, which when combined with the transmission rights become equivalent to physical bilateral contracts [79].

On the other hand, opponents of the centralized model argue that the SO becomes too powerful an entity, with a significant impact on the overall system operation, and then welfare of each market participant. This calls for a tight control of the SO by other regulatory and independent bodies. Some believe that this is a serious argument against such a centralized model. They also argue that the efficiency of a centrally determined dispatch is sensitive to the truthful disclosure of generator costs, as well as to approximations and assumptions adopted in the optimization procedures [21]. Also, this type of a model requires very well formulated economic incentives [75].

Predominantly Bilateral Trading with Physical Bilateral Contracts

This is a model where market participants are encouraged to enter into bilateral trades which, when approved by the SO, are actually realized. The SO is still responsible to maintain reliable system operation, but it has to honor the pre-approved contracts. Only in the case of congestion or out of merit operation may bilateral parties be asked to adjust their original schedules. Furthermore, all market participants can trade through a Power Exchange (PX) that is essentially a centralized market. In contrast to pool markets, the PX is not integrated into the SO, but is just another market player that submits its trades for approval.

Because trading and coordinating functions are completely separated, this model is also referred to as *Decentralized* or *Unbundled*. Its Proponents emphasize the "freedom of choice", and the absence of "invisible hand of the SO". Also, they argue that bilateral contracts help offset the market power of generators, and point out the weakness of optimization procedures, especially with the various approximations usually assumed.

Summary of Trading Models

A summary and comparison of primarily pool (integrated) and primarily bilateral (unbundled) models is given in Table 2-1 [72].

	Primarily Pool *(Integrated)*	**Primarily Bilateral** *(Unbundled)*
Type of System Operator	Independent	Independent
Scheduling	Based on generation offers	Matched schedules
Pricing	Marginal	According to bilateral agreements
Balancing services	Integrated with centralized pool market	Separate balancing market
Transmission rights	Financial	Physical or financial
Congestion management	Integrated with centralized pool market	Congestion market or tradable transmission rights
Provision of reserves	Reserve markets are integrated with centralized pool market	Reserve markets, preferably integrated with balancing market

Table 2-1. Summary of trading models [72]

Chapter 3.

Combined Pool/Bilateral Operation

Markets that allow both pool and bilateral trading are currently cleared via a two-step procedure that in a first pass assumes that the two markets are independent. This assumption implies that, in the first step, the bilateral contracts have little or no influence on system losses, transmission congestion, as well as pool prices [67, 80]. Only in a second step, does the SO examine whether security constraints are violated and, if necessary, readjusts the pool and, possibly, the bilateral levels [68]. A variation of this two-step approach is to send sensitivity signals to the bilateral parties to help them re-negotiate bilateral contracts to new levels that will relieve congestion [17, 66].

The market model proposed in this thesis is based on a one-step optimal power flow that simultaneously takes into consideration pool trades and bilateral contracts while minimizing cost [81]. The optimization model also accounts for both transmission losses and congestion. The solution of this optimization problem defines the market clearing process, and yields the optimum levels of "pool" generation together with the Lagrange multipliers associated with the power balance equations at each node. Under marginal pricing, these multipliers become the pool nodal prices (or locational marginal prices), which reflect the combined pool/bilateral operation with all its constraints. One advantage of this model is that heuristic ex-post corrections are not required to account for losses or transmission constraints, as is the case in two-step methods. Such heuristics generally introduce inefficiencies in the form of higher total cost and cross-subsidies among competing agents [82]. The disadvantage of the proposed model is that it is more complex, as it considers all the variables and constraints simultaneously, and requires greater computational effort.

An assumption that is made throughout this chapter is that the bilateral contracts have been pre-approved by the SO, which means that the generators have the right and the obligation to inject into the network the total amount of power defined by their contracts. Approval of the bilateral contracts by the SO also implies that each contract is guaranteed sufficient transmission capability from the sending (injection) to the receiving bus (consumption). Chapter 5 analyses a more general case where some of the bilateral contracts may not be pre-approved and are subject to curtailment.

This chapter is organized as follows: First, the market structure of the proposed combined pool/bilateral market is outlined. Next, the generation and load levels are decomposed into pool and bilateral components. This is followed by the optimal power flow model characterizing the combined pool/bilateral operation. The pricing of the various pool and bilateral components is then discussed, from which technical and financial performance measures are defined for each competing entity. These performance measures allow each market participant to evaluate the profitability of a particular bilateral contract, as well as the overall performance of the chosen mix of pool and bilateral trades. The ultimate objective is for each participant to use these measures to plan its relative level of participation in the pool versus the bilateral market.

3.1 Proposed Pool/Bilateral Market Model Structure

Figure 3-1 shows a schematic structure of the proposed combined pool/bilateral market, and illustrates the relationships between the various market participants. In this model, the SO simultaneously carries out three main functions:

- Auction;
- Network operation;

➢ Ancillary services.

The network operation function collects all line data, including flow limits, and sets up the load flow equations at each bus and the power flow relations at each transmission line. The auction function collects the voluntary generator offers to the pool as well as the generator operational limits together with the previously negotiated bilateral contracts. If the loads are elastic, a similar set of data defining the load bids to the pool is also collected; however in this thesis the assumption is that the loads are inelastic. The market clearing procedure based on a minimum cost optimization dispatch then yields the generator outputs and the prices of the pool-supplied energy at each bus. The ancillary services required by the bilateral contracts (such as the transmission losses and any generation congestion re-dispatch due to transmission congestion and maximum generation output limits), which are attributed to bilateral contracts, can also be found from the market clearing process.

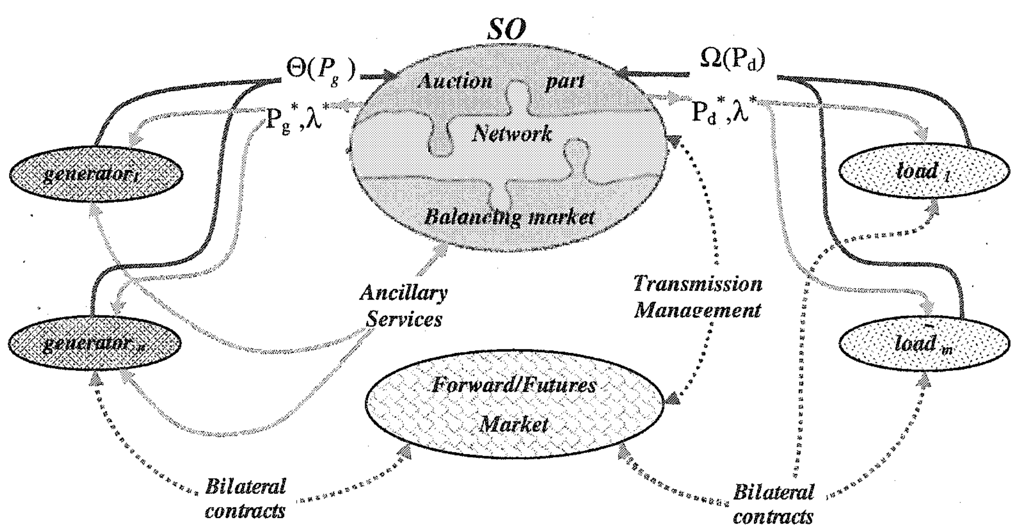

Figure 3-1. Proposed combined pool/bilateral market structure

3.2 Combined Pool/Bilateral Dispatch: A Mathematical Model

In the next two sub-sections first the generation and load variables are decomposed into pool and bilateral components. This is followed by a mathematical framework of the proposed combined pool/bilateral market.

The models that follow all assume that the loads are inelastic and specified and that the bilateral contracts are physical rather than financial. In this chapter, in addition, the bilateral contracts are considered firm (non-curtailable).

3.2.1 Load and Generation Pool and Bilateral Components

In a mixed pool/bilateral market, the vector of the given real power demands at all the buses of an n-bus network is denoted by,

$$\mathbf{P}_d = \{P_{d_j}; j = 1,...,n\},$$

This has two components,

- the "bilateral demand" component defined by the bilateral contracts,

$$\mathbf{P}_d^b = \{P_{d_j}^b; j = 1,...,n\},$$

- the "pool demand" component defined by the difference between the total and the bilateral demand, $\mathbf{P}_d^p = \{P_{d_j}^p; j = 1,...,n\}$, so that,

$$\mathbf{P}_d = \mathbf{P}_d^p + \mathbf{P}_d^b. \tag{3.1}$$

In addition, the bilateral load components, $P_{d_j}^b$, are decomposable into the sum of the specified firm bilateral contracts with the supplying generators, that is,

$$P_{d_j}^b = \sum_{i=1}^{n} GD_{ij}, \tag{3.2}$$

where GD_{ij} denotes a bilateral contract *delivered* at load at bus j from generator at bus i [83]. For the sake of simplicity, it is assumed that each bus has only one load and/or one generator. Defining now the vector $\mathbf{e} = \{1,1,...,1\}^T$ of dimension n and using (3.2), the bilateral demand vector $\mathbf{P}_d^b$ can be more compactly expressed as,

$$\mathbf{P}_d^b = \mathbf{GD}^T \cdot \mathbf{e}, \tag{3.3}$$

where $\mathbf{GD} = \{GD_{ij}, i = 1,...,n; j = 1,...,n\}$ is the matrix of bilateral contracts.

One of the tasks of the manager of a load-supplying entity is to establish a "best" mix of pool and bilateral levels, in other words, the relative levels of $\mathbf{P}_d^b$ and $\mathbf{P}_d^p$ that will meet the load in the most economical manner to the consumer. As this thesis will show, the relative pool/bilateral mix is critical in this respect. The same comment applies to the manager of a generating company.

Similarly, the scheduled bilateral generations can also be described as,

$$P_{g_i}^b = \sum_{j=1}^{n} GD_{ij}, \tag{3.4}$$

which, in vector form, becomes,

$$\mathbf{P}_g^b = \mathbf{GD} \cdot \mathbf{e}. \tag{3.5}$$

The total generation vector, $\mathbf{P}_g$, is here defined as the sum of the scheduled bilateral contracts, $\mathbf{P}_g^b$, and the pool generation component, $\mathbf{P}_g^p$, that is,

$$\mathbf{P}_g = \mathbf{P}_g^b + \mathbf{P}_g^p. \tag{3.6}$$

Since the bilateral generation contracts do not include the supply of losses, this function becomes the sole responsibility of the pool. Therefore, the pool generation defined as $\mathbf{P}_g^p$, is that component of $\mathbf{P}_g$ supplying both the pool demand, $\mathbf{P}_d^p$, as well as any transmission losses and generation re-dispatch due to the combined effect of the pool and the bilateral demands. There may be other ways of supplying the losses attributed to the bilateral contracts, however these methods are much more complex than the pool-supply method proposed here [67, 84].

Similarly, if transmission constraints become a factor, the generation must be adjusted to avoid line overloading. In general, this adjustment can be accomplished by varying the bilateral contracts, the pool generation component, or a combination of both. In this model, any re-dispatch to manage congestion due to either the pool or the bilateral demands is also the sole responsibility of the pool through the component $\mathbf{P}_g^p$.

3.2.2 Formulation of a Combined Pool/Bilateral Market Clearing Dispatch Procedure

If generator i wishes to sell power to the pool market, it submits an *offer*, that includes the supply function, $\Theta_{gi}(P_{g_i})$, plus the upper and lower limits on the generation level, P_{gi}. In competitive markets, the offered supply function need not be equal to the true cost curve, $C_{gi}(P_{gi})$, which is generally known only to the generating company.

As previously stated, such offers are used to supply not only the pool part of the demand, $\mathbf{P}_d^p$, but also the system losses as well as any ancillary services required by both the pool and bilateral demands, respectively, $\mathbf{P}_d^p$ and $\mathbf{P}_d^b$.

The SO clears the combined pool/bilateral market by minimizing the sum of the offered supply functions, known as the *aggregate supply function*,

$$\Theta = \Theta_g(\mathbf{P}_g) = \sum_{i=1}^{n} \Theta_{gi}(P_{g_i}) \tag{3.7}$$

while respecting all system constraints[12].

Using the notation of (3.1) - (3.6), the combined pool/bilateral market clearing strategy can, therefore, be expressed by the following OPF problem,

$$\underset{\mathbf{P}_g,\mathbf{Q}_g,\mathbf{V},\boldsymbol{\delta}}{Min} \quad \Theta_g(\mathbf{P}_g) = \sum_i \Theta_{gi}(P_{gi}) \tag{3.8}$$

$$\begin{aligned} s.t. \quad & (\mathbf{P}_g,\mathbf{Q}_g,\mathbf{V},\boldsymbol{\delta}) \in S \\ & \mathbf{P}_g \geq \mathbf{P}_g^b = \mathbf{GD}\cdot\mathbf{e} \end{aligned}$$

The set S above denotes the security region of the power system in the space of generation levels and bus voltages, ($\mathbf{P}_g,\mathbf{Q}_g,\mathbf{V},\boldsymbol{\delta}$). Such a region is defined by:

- the load flow equations,

$$\mathbf{P}_g = \mathbf{P}_d + \mathbf{P}(\mathbf{V},\boldsymbol{\delta}) \quad \text{and} \quad \mathbf{Q}_g = \mathbf{Q}_d + \mathbf{Q}(\mathbf{V},\boldsymbol{\delta}),$$

- the range of real and reactive generation,

$$\mathbf{P}_g^{\min} \leq \mathbf{P}_g \leq \mathbf{P}_g^{\max} \quad \text{and} \quad \mathbf{Q}_g^{\min} \leq \mathbf{Q}_g \leq \mathbf{Q}_g^{\max},$$

- the voltage magnitude limits,

$$\mathbf{V}^{\min} \leq \mathbf{V} \leq \mathbf{V}^{\max},$$

- and the transmission flow limits,

$$\left|\mathbf{P}_f(\mathbf{V},\boldsymbol{\delta})\right| \leq \mathbf{P}_f^{\max}.$$

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[12] In a more general approach, the objective function of (3.7) would be to maximize the total social welfare, W, defined as,

$$\begin{aligned} W &= \Omega_d(\mathbf{P}_d) - \Theta_g(\mathbf{P}_g) \\ &= \sum_{j=1}^{n} \Omega_{dj}(P_{dj}) - \sum_{i=1}^{n} \Theta_{gi}(P_{gi}), \end{aligned}$$

where $\Omega_{dj}(\mathbf{P}_{dj})$ is the bid submitted by load j to the pool, which, in essence, is a *demand curve* that shows how much a load j is willing to consume at each price. It also reflects the demand elasticity with regard to the pool price. As loads are considered inelastic in this thesis, the demand curve is constant and can be omitted from the objective function.

The solution of (3.8) yields the optimum levels of all decision variables, including the generation vector, $\mathbf{P}_g$, as well as the Lagrange multipliers associated with all constraints. The pool generation component can then be found by subtracting the scheduled bilateral generation, that is,

$$\mathbf{P}_g^p = \mathbf{P}_g - \mathbf{P}_g^b. \tag{3.9}$$

What distinguishes the combined pool/bilateral formulation in (3.8) from the pure pool dispatch (with no bilateral transactions) is the additional vector inequality, $\mathbf{P}_g \geq \mathbf{P}_g^b$, that establishes the minimum generation levels dictated by the bilateral contract commitments. If active, this restriction indicates that some generators have over-committed themselves to bilateral trades. A more detailed discussion of the characteristics of this combined market model is found in Chapter 4.

3.3 Pricing Services in Combined Pool/Bilateral Markets

As the bilateral contracts, $GD_{ij}; i = 1,...,n; j = 1,...,n$, are privately negotiated, it is assumed that each has its own pre-determined rate, π_{ij}^b. These contracts, however, are agreements for power only, excluding the associated ancillary services provided by the pool. The involved parties must pay the pool for the ancillary services separately. As mentioned before, in this market model, these ancillary services are part of the pool generation component that also includes the supply of pool demand and its associated ancillary services. The pricing scheme of these services and of supplying the pool demand follows two basic philosophies, namely marginal and Pay-as-Bid pricing, both of which are detailed in Chapters 4 and 6. However, irrespective of the pricing scheme chosen, the dispatching of the pool generation in the model proposed in this thesis is always based on the optimization problem (3.8).

In addition to the above mentioned ancillary services, as both pool and bilateral trades make use of the network infrastructure, an additional charge for network usage may be imposed to recover the network cost and to remunerate the transmission provider [85].

3.4 Financial Performance Measures

As the main objective of each market participant is to increase its financial welfare, it is important for each party to be able to evaluate its profit as a function of its pool/bilateral mix[13]. Whereas a load can completely specify its pool/bilateral mix, a generator can only specify its level of bilateral generation, as the level of pool supply depends on its offer to the pool and on the outcome of the overall system optimization.

To evaluate the economic benefit of a particular pool/bilateral mix, this section develops two types of performance measures from the perspective of individual generators and loads. These measures, which are divided into revenues and expenditures, are first developed for the general case, irrespective of the pricing method, and are later expanded to the specific cases of marginal and Pay-as-Bid pricing in Chapters 4 and 6 respectively.

3.4.1 Generator Revenues and Expenditures

In this section, we begin with the assumption that the SO has cleared the market according to the optimization problem (3.8), and that it has determined a set of nodal prices for all pool quantities. Thus, at bus i, the price charged by a generator for pool services is π^{p}_{gi}, while the price paid by a load is π^{p}_{di} . As will be seen in Chapter 6, under

[13] The pool/bilateral mix of a load or a generator is defined as the relative level of pool versus bilateral participation.

Pay-as-Bid pricing, these two prices may differ, but under marginal pricing they are equal to the nodal price or locational marginal price,

$$\pi_{gi}^{p} = \pi_{di}^{p} = \lambda_i \tag{3.10}$$

When a nodal generation price, π_{gi}^{p}, is applied to the pool component $P_{g_i}^{p}$, the revenue of generator i from all pool-related services (including the supply of losses and congestion management attributed to bilateral contracts) becomes,

$$R_{gi}^{p} = \pi_{gi}^{p} \cdot P_{gi}^{p}\,. \tag{3.11}$$

The second source of revenue for generator i, as indicated in Figure 3-2, comes from its bilateral trades, $GD_{ij};\forall j$. Under the assumption that each bilateral contract with load j is charged by generator i at the privately negotiated bilateral rate, π_{ij}^{b}, this second revenue component is,

$$R_{gi}^{b} = \sum_{j=1}^{n} \pi_{ij}^{b} \cdot GD_{ij}\,. \tag{3.12}$$

In addition, generator i has an *expenditure* for the ancillary services required by the power transfer of each of its bilateral contracts GD_{ij}. This expenditure is denoted by E_{ij}^{bcl}, where the subscript "bcl" stands for "bilateral constraint/loss". Since this expenditure depends on the point of injection of the bilateral contract, i, and the point of consumption, j, each contract has its own power transfer price, π_{ij}^{bcl}. This price is determined by the SO based on the optimization procedure of (3.8) and on the pricing mechanism used according to the procedures described in Chapters 4 and 6. The power transfer payment of contract GD_{ij} is therefore,

$$E_{ij}^{bcl} = \pi_{ij}^{bcl} \cdot GD_{ij}\,. \tag{3.13}$$

As E_{ij}^{bcl} is associated with a bilateral trade, rather than with the selling-generator i or with the buying load j, this payment can be split in arbitrary proportions between these two entities. Under the assumption that generator i is responsible for the part k (where parameter $k \in [0,1]$) this generator will be assigned an expenditure of kE_{ij}^{bcl} for the power transfer of contract GD_{ij}, while load j will be charged $(1-k)E_{ij}^{bcl}$. The total obligations of generator i for ancillary services required by all its contracts are therefore,

$$E_{gi}^{bcl} = k\sum_{j=1}^{n} \pi_{ij}^{bcl} \cdot GD_{ij}. \tag{3.14}$$

Thus, due to these power transfer payments the net price that generator i sees for its bilateral trade GD_{ij} is not equivalent to the bilateral sale price, π_{ij}^{b}, but rather reflects all the revenues and expenditures associated with that contract. Therefore, from the point of view of generator i, its net bilateral price can be defined as,

$$\hat{\pi}_{gij}^{b} = \pi_{ij}^{b} - k\frac{E_{ij}^{bcl}}{GD_{ij}}. \tag{3.15}$$

Combining (3.11) - (3.14), the net revenue of generator i is finally,

$$\begin{aligned} R_{gi} &= R_{gi}^{p} + R_{gi}^{b} - E_{gi}^{bcl} \\ &= \pi_{gi}^{p} \cdot P_{gi} + \sum_{j=1}^{n} \pi_{ij}^{b} \cdot GD_{ij} - k\sum_{j=1}^{n} \pi_{ij}^{bcl} \cdot GD_{ij} \end{aligned} \tag{3.16}$$

while its profit equals the difference between this revenue and the true cost of generation, $C_{gi}(P_{gi})$, that is,

$$pr_{gi} = R_{gi}^{p} + R_{gi}^{b} - E_{gi}^{bcl} - C_{gi}(P_{gi}). \tag{3.17}$$

Since the true cost function, $C_{gi}(P_{gi})$, and therefore its true profit, is information known only to the generator, the analyses in this thesis are carried out only with respect to the generator revenue, R_{gi}, defined in (3.16).

3.4.2 Load Revenues and Expenditures

Similarly to the generators, a load *j* has two expenditure terms. The first corresponds to the pool demand component, P_{dj}^{p}, purchased at the pool nodal price, π_{dj}^{p}, that is,

$$E_{dj}^{p} = \pi_{dj}^{p}\ P_{dj}^{p}. \tag{3.18}$$

The second term is the bilateral contract payment charged at the privately negotiated bilateral rates, π_{ij}^{b}:

$$E_{dj}^{b} = \sum_{i=1}^{n} \pi_{ij}^{b}\ GD_{ij}. \tag{3.19}$$

In addition, for each contract, a load is responsible for the other part of the expenditure for ancillary services required by bilateral trades, defined in (3.13), that is $(1-k)E_{ij}^{bcl}$. Thus the total expense of load *j* for these ancillary services is:

$$E_{dj}^{bcl} = (1-k)\sum_{i=1}^{n} \pi_{ij}^{bcl}\, GD_{ij}. \tag{3.20}$$

Similarly to the generators, the net bilateral price that reflects the expenditures of load *j* associated with bilateral trade GD_{ij} can be defined as,

$$\hat{\pi}_{dij}^{b} = \pi_{ij}^{b} + (1-k)\frac{E_{ij}^{bcl}}{GD_{ij}}. \tag{3.21}$$

This net price gives a more complete picture about the cost of the bilateral trade from the point of the load than the bilateral price, π_{ij}^{b}.

The total expenditure of load *j* is then,

$$\begin{aligned} E_{dj} &= E_{dj}^{p} + E_{dj}^{b} + E_{dj}^{bcl} \\ &= \pi_{dj}^{p} \cdot P_{dj} + \sum_{i=1}^{n} \pi_{ij}^{b}\ GD_{ij} + (1-k)\sum_{i=1}^{n} \pi_{ij}^{bcl}\ GD_{ij} \end{aligned} \tag{3.22}$$

In addition, the benefit function, $B_{dj}\left(P_{dj}\right)$, measures the revenue of load j in terms of the power consumed, P_{dj}. The benefit function does not have to be the same as the bid function $\Omega_{dj}(P_{dj})$ that load j submits to the pool. The difference between the benefit function and the total expenditure of (3.22) defines the profit of load j,

$$pr_{dj} = B_{dj}\left(P_{dj}\right) - \left(E_{dj}^{p} + E_{dj}^{b} + E_{dj}^{bcl}\right). \tag{3.23}$$

Similarly to the generators, since benefit functions are confidential, the analyses in this thesis are carried out with respect to load expenditures only, as defined in (3.22).

Figure 3-2 illustrates the monetary flows of the revenues and expenditures defined above.

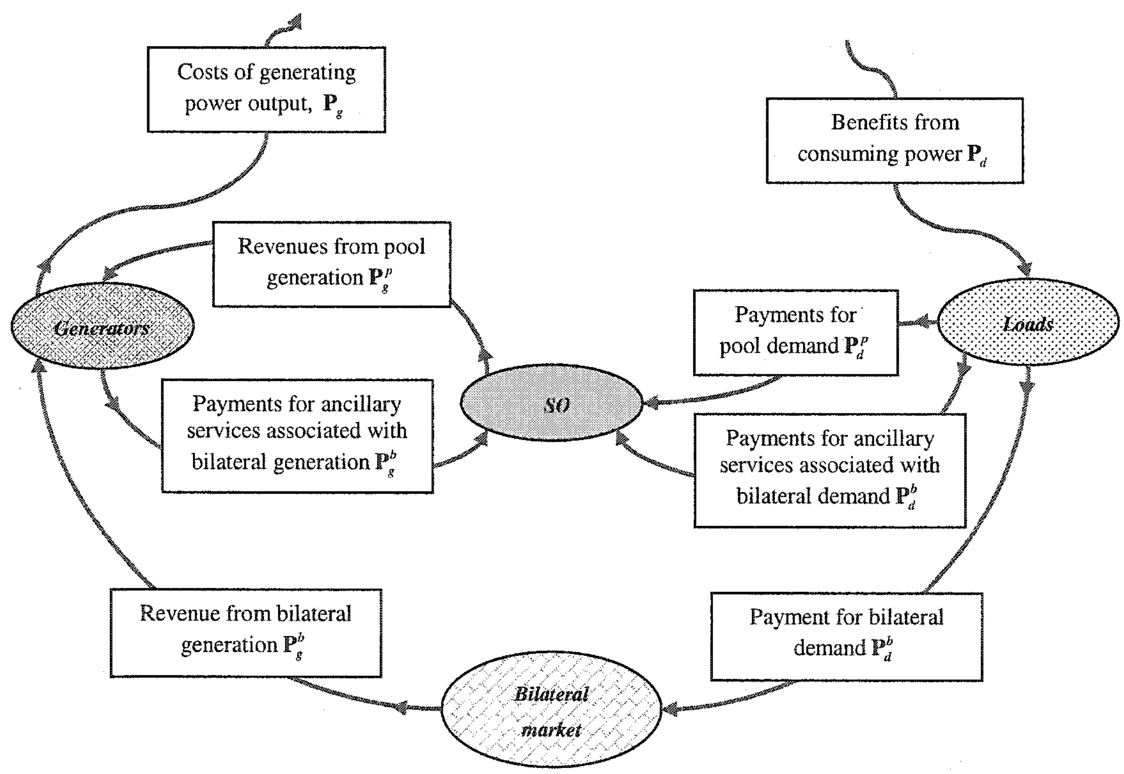

Figure 3-2. Monetary flows in the proposed combined pool/bilateral market

3.4.3 Merchandising Surplus

In addition to the financial performance measures defined from the perspective of the loads and the generators, a financial measure from the point of view of the SO can also be identified, typically referred to as the *merchandising surplus* (MS). This quantity denotes the difference between the money that the SO collects and what it pays. From, Figure 3-2 and using equations (3.11)-(3.23),

$$MS = \sum_{j=1}^{n}\left(E_{dj}^{p} + E_{dj}^{bcl}\right) - \sum_{i=1}^{n}\left(R_{gi}^{p} - E_{gi}^{bcl}\right)$$

$$= \sum_{j=1}^{n}\left(\pi_{dj}^{p}\, P_{dj}^{p} + (1-k)\sum_{i=1}^{n}\pi_{ij}^{bcl}\cdot GD_{ij}\right) - \sum_{i=1}^{n}\left(\pi_{gi}^{p}\, P_{di}^{p} - k\sum_{j=1}^{n}\pi_{ij}^{bcl}\, GD_{ij}\right). \quad (3.24)$$

$$= \sum_{i=1}^{n}\pi_{dj}^{p}\, P_{dj}^{p} - \sum_{j=1}^{n}\pi_{gi}^{p}\, P_{gi}^{p} + \sum_{i,j=1}^{n}\pi_{ij}^{bcl}\, GD_{ij}$$

Since the total bilateral payments of all generators are equal to the total bilateral expenditures of all loads, $\sum_{i=1}^{n} R_{gi}^{b} = \sum_{j=1}^{n} E_{dj}^{b}$, the MS of (3.24) can also be expressed in terms of the total load expenditures and generator revenues as,

$$MS = \sum_{j=1}^{n} E_{dj} - \sum_{i=1}^{n} R_{gi}\,. \quad (3.25)$$

Under marginal pricing, the MS in non-negative but under Pay-as-Bid it is always zero. In the case when it is non-zero, the surplus is not a profit to the SO, which is an independent, profit-neutral entity. This money is used for other expenses, such as to cover the network use charge of the transmission provider.

The chapter that follows analyzes the application of the proposed combined pool-bilateral model and the associated financial performance measures to a market operating under Locational Marginal Pricing (LMP).

Chapter 4.

Combined Pool/Bilateral Operation with Locational Marginal Pricing

The role of prices in an electricity market is to provide each participant with incentives that reflect the financial impact of its degree of participation in the market, while ensuring a balance between supply and demand. One way to set the price of electricity is through the common Marginal Pricing method, with its variations of System Marginal Pricing (SMP) and Locational Marginal Pricing (LMP). In essence, the marginal price measures the rate of change of the cost or social welfare if an output increases by one unit, thus showing how much it costs to produce the next MW of power.

The model developed in the previous chapter is based on an optimal power flow (OPF) for given generator offers and levels of firm bilateral contracts. The OPF determines the optimum levels of pool generation together with the Lagrange multipliers associated with the power balance equations at the various network nodes. Under LMP, these Lagrange multipliers become the locational marginal or nodal prices for pool trading, which in this Chapter 4 are applied to the proposed pool/bilateral market model. Nodal prices are applied to the pool generation components that include the supply of pool demand and its associated losses plus any generation re-dispatch, as well as the ancillary services attributed to bilateral contracts. In this chapter, the bilateral contracts are considered firm physical rights and obligations to deliver power from one specified point of the network to another. It is also assumed that the bilateral agreements are pre-approved by the SO.

The outline of this chapter is the following. First, the pricing of pool and bilateral components in this combined model is discussed and compared to other models that also apply the marginal pricing mechanism. Then, the influence of the chosen pool/bilateral mix on system operation and on individual financial performances of the market participants is analyzed using the general financial measures developed in Chapter 3. Under firm bilateral contracts, high bilateral load components can lead to out-of-merit operation, congestion, high nodal prices and high power transfer payments. These signals correctly reflect poor planning decisions on the part of the market participants and provide incentives to these participants to modify their trading behaviour in the future. However, because such planning is not easy in the presence of uncertain behaviour of the competing traders, an extended pool/bilateral market model is suggested that includes mechanisms that permit the system operator and the market participants to curtail the bilateral contracts if, by so doing, the system welfare improves. These suggestions are addressed in Chapter 5.

4.1 Pool and Bilateral Locational Marginal Pricing

In the proposed combined pool/bilateral model, under marginal pricing, the Lagrange multipliers, $\lambda_i; i=1,...,n$, calculated from the OPF procedure defined by (3.8) become the locational marginal or nodal prices. The multiplier λ_i is the price charged by the SO to the pool demand at this bus, P_{di}^{p}, as well as the rate at which generator i collects for its pool generation component, P_{gi}^{p}. It is important to emphasize that since these nodal prices reflect both the transmission losses and any generation re-dispatch, no additional charges are required to cover such services.

As stated earlier, bilateral contracts are for power delivered and do not include the supply of the ancillary services necessary for these contracts to be executed in a real network. In the proposed model these services must be purchased from the pool, and, under locational marginal pricing (LMP), they are priced according to the nodal price difference between the sending and receiving buses of each specific bilateral trade GD_{ij}, that is,

$$\pi_{ij}^{bcl} = \lambda_j - \lambda_i \tag{4.1}$$

The derivation of equation (4.1) is given in Appendix A. In practice, this marginal price difference is often referred to as the *point-to-point transmission service charge* [79, 86], or the *congestion rent*, but in this thesis, it is called the *power transfer* price. The power transfer charge imposed by the SO to the bilateral contract GD_{ij} is then $(\lambda_j - \lambda_i)GD_{ij}$, and as shown in Appendix A under marginal pricing this charge accounts for the losses and congestion and re-dispatch[14] due to bilateral trades.

The power transfer prices are calculated from the optimization scheduling procedure of (3.8) and therefore depend on the system operating point and reflect the levels of participation of all market participants. For instance, if the overall pool/bilateral mix leads to an "out of merit" operation under which some lower generation limits due to the bilateral contracts (in $\mathbf{P}_g \geq \mathbf{P}_g^b$) become active[15], the nodal prices go up thus driving up the cost of pool generation. In the worst case, high levels of lower bilateral limits can lead to transmission congestion, to high nodal price differences, and to high power transfer charges.

The nodal prices, the price differences, and the power transfer payments described above have a profound significance, as they send financial signals to all market participants. In this pool/bilateral model, these signals help buyers and sellers evaluate whether a chosen set of bilateral partners and pool/bilateral mix is profitable.

One characteristic of the nodal prices and the power transfer charges defined above is that their amount is exactly known only after all the participants submit their pool offers and their bilateral contracts, and after the SO clears the market by solving the corresponding OPF of (3.8). As this approach entails financial uncertainty, some markets

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[14] Therefore, under the marginal pricing the "bcl" stands for "bilateral congestion/loss".

[15] A lower generation limit due to bilateral contracts is referred to in this thesis as a "lower bilateral limit".

have introduced the notion of Financial Transmission Right (FTR) which is pre-purchased periodically through auctions, and is an instrument to hedge against high power transfer charges [58, 60, 87].

The problem with this approach is that an FTR does not directly send the bilateral contract parties adequate price incentives to reduce the level of congestion and unnecessarily high social costs. Instead, these methods assume that the trading of transmission rights in a market would yield efficient congestion management, as the cost of acquiring an FTR for frequently congested lines is expected to rise. However, gaming in FTR markets [33], as well as scarcity of transmission rights [54], could introduce inefficiencies and lead to difficulties in clearing the market. Furthermore, holders of FTR are entitled to collect the revenue from the congestion charges, even though such holders may not actually be transferring power. Therefore, FTR are vulnerable to gaming, as some strategically positioned holders may use them to manipulate the system and increase their profits.

The model presented here applies the power transfer charges of (4.1) to *all* bilateral trades. Similarly to [88] these congestion rents are considered essential signals for adequate congestion management because market players then face the true cost of their actions. As the results of this chapter show, true congestion rents or, as this thesis calls them, power transfer charges, can dissuade participants from causing congestion, unintentional or otherwise, through better planning of their bilateral agreements.

Since this type of long-term planning is hindered by uncertainty about how the competition will behave, this thesis also examines in the next chapter some mechanisms through which the trading partners may allow the SO to modify their requested transactions at the time of scheduling in order to avoid congestion and to maximize social welfare.

4.2 Financial Performance Measures under Locational Marginal Pricing

4.2.1 Generator Revenues and Expenditures

Under LMP, pool sales at bus i are charged at the Locational Marginal Price, that is, $\pi_{gi}^{p} = \lambda_i$. Then, the part of the revenue of generator i that comes from its pool sales is,

$$R_{gi}^{p} = \lambda_i \cdot P_{gi}^{p} . \tag{4.2}$$

The generator revenue from its bilateral sales, P_{gi}^{b}, calculated at the privately set bilateral rates, π_{ij}^{b}, is not affected by the pool dispatch, and remains as defined by (3.12),

$$R_{gi}^{b} = \sum_{j=1}^{n} \pi_{ij}^{b} \cdot GD_{ij} . \tag{4.3}$$

In what concerns the generator expenditures, they are associated with its bilateral trades, and are defined by the combined power transfer payments for loss supply and congestion management. Here it is assumed that generators are responsible for half of this charge while the loads are assigned the remaining half, so that the parameter k in (3.14) is defined as $k = 0.5$. Thus, following equation (3.14), the power transfer obligation of generator i under LMP pricing is,

$$E_{gi}^{bcl} = \frac{1}{2} \sum_{j=1}^{n} (\lambda_j - \lambda_i) GD_{ij} . \tag{4.4}$$

Note that if a power transfer payment is negative, then the pool reimburses the parties concerned, a situation that could occur if a particular contract tends to reduce congestion or losses.

Taking into consideration the previous power transfer payments, the net rate of bilateral trade GD_{ij} seen by the selling generator i and defined by (3.15) now becomes,

$$\hat{\pi}^b_{gij} = \pi^b_{ij} - \frac{\lambda_j - \lambda_i}{2}. \tag{4.5}$$

Finally, the net revenue of generator i is,

$$\begin{aligned} R_{gi} &= R^p_{gi} + R^b_{gi} - E^{bcl}_{gi} \\ &= \lambda_i \cdot P^p_{gi} + \sum_{j=1}^{n} \pi^b_{ij} \cdot GD_{ij} - \frac{1}{2}\sum_{j=1}^{n}(\lambda_j - \lambda_i) \cdot GD_{ij} \end{aligned} \tag{4.6}$$

while its profit equals,

$$pr_{gi} = R^p_{gi} + R^b_{gi} - E^{bcl}_{gi} - C_{gi}(P_{gi}). \tag{4.7}$$

4.2.2 Load Revenues and Expenditures

Under LMP, load j pays for its pool purchases, P^p_{dj}, at the nodal price, λ_j, so that the corresponding expenditure is,

$$E^p_{dj} = \lambda_j P^p_{dj}. \tag{4.8}$$

The second expense is the bilateral contract payment charged at the privately negotiated bilateral rates, π^b_{ij}, which remains as defined by (3.19),

$$E^b_{dj} = \sum_{i=1}^{n} \pi^b_{ij} \cdot GD_{ij}. \tag{4.9}$$

For each of its bilateral contracts, the load is also responsible for half of the power transfer expenditure, $E^{bcl}_{ij}/2$, so that its total power transfer expense is,

$$E^{bcl}_{dj} = \frac{1}{2}\sum_{i=1}^{n}(\lambda_j - \lambda_i) \cdot GD_{ij}. \tag{4.10}$$

Similarly to generators, the net rate of bilateral trade GD_{ij} seen by load j is,

$$\hat{\pi}^b_{dij} = \pi^b_{ij} + \frac{\lambda_j - \lambda_i}{2}. \tag{4.11}$$

The revenue of load j is its benefit function, $B_{dj}(P_{dj})$, generally of a confidential nature and unknown to the SO. The total expenditure of load j is therefore,

$$\begin{aligned} E_{dj} &= E^p_{dj} + E^b_{dj} + E^{bcl}_{dj} \\ &= \lambda_j \cdot P_{dj} + \sum_{i=1}^{n} \pi^b_{ij} \cdot GD_{ij} + \frac{1}{2}\sum_{i=1}^{n}(\lambda_j - \lambda_i) \cdot GD_{ij} \end{aligned} \tag{4.12}$$

with the profit being,

$$pr_{dj} = B_{dj}(P_{dj}) - (E^p_{dj} + E^b_{dj} + E^{bcl}_{dj}). \tag{4.13}$$

Figure 4-1 shows the monetary flows of revenues and expenditures under LMP.

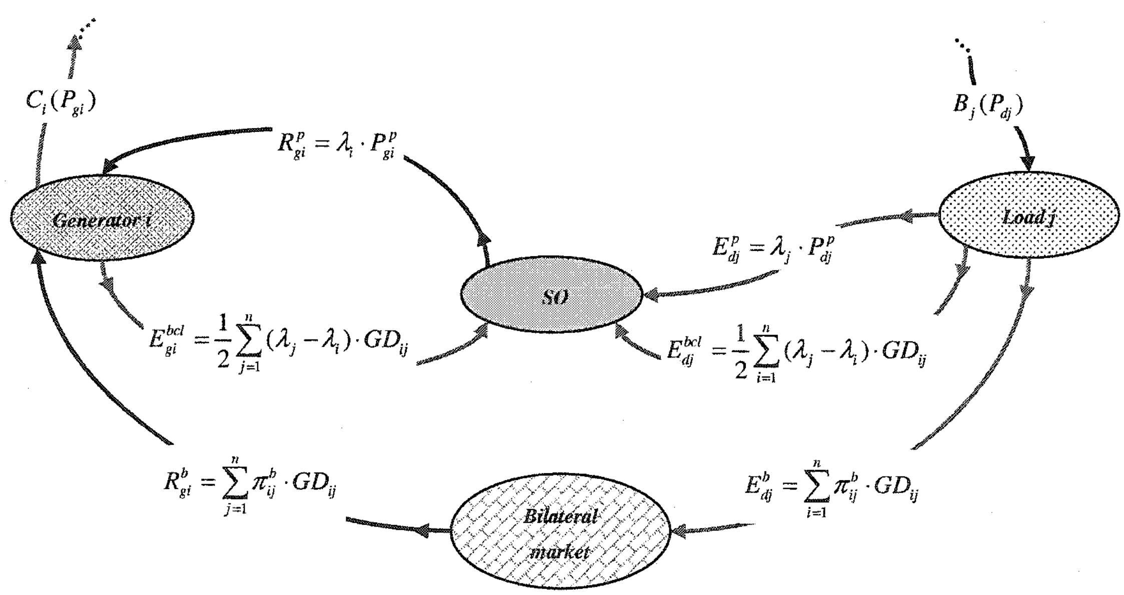

Figure 4-1. Monetary flows in the combined pool/bilateral market under LMP.

4.2.3 Merchandising Surplus

Substituting the expressions for load expenses and generator revenues of (4.6) and (4.12), respectively, into (3.25), yields the value of the merchandising surplus, *MS*, collected by the SO,

$$\begin{aligned} MS &= \sum_{j=1}^{n} E_{dj} - \sum_{i=1}^{n} R_{gi} \\ &= \sum_{i=1}^{n} \lambda_i (P_{di}^p - P_{gi}^p) + \sum_{i,j=1}^{n} (\lambda_j - \lambda_i) GD_{ij} \end{aligned} \tag{4.14}$$

4.2.4 Total Revenues and Expenditures - Other Perspectives

The main objective of the previous financial performance measures is to assist market participants in evaluating the benefits of a chosen pool/bilateral mix by decomposing the total generator revenues and load expenditures into components that correspond to the pool and bilateral trades. However, equations (4.6) and (4.12) can also be expressed respectively as,

$$\begin{aligned} R_{gi} &= \lambda_i P_{gi} + \sum_{j=1}^{n} \left[\pi_{ij}^b - \frac{(\lambda_i + \lambda_j)}{2} \right] GD_{ij} \\ &= \hat{R}_{gi}^p + \hat{R}_{gi}^b \end{aligned} \tag{4.15}$$

and,

$$\begin{aligned} E_{dj} &= \lambda_j P_{dj} + \sum_{i=1}^{n} \left[\pi_{ij}^b - \frac{(\lambda_j + \lambda_i)}{2} \right] GD_{ij} \\ &= \hat{E}_{dj}^p + \hat{E}_{dj}^b \end{aligned} \tag{4.16}$$

The total generation revenue is now defined as the sum of two different terms,

$$\hat{R}_{gi}^p = \lambda_i P_{gi}, \tag{4.17}$$

and

$$\hat{R}^b_{gi} = \sum_{j=1}^{n}\left[\pi^b_{ij} - \frac{(\lambda_i + \lambda_j)}{2}\right] GD_{ij}. \tag{4.18}$$

Similarly, the total load expenditures consist of two terms,

$$\hat{E}^p_{dj} = \lambda_j P_{dj}, \tag{4.19}$$

and

$$\hat{E}^b_{dj} = \sum_{i=1}^{n}\left[\pi^b_{ij} - \frac{(\lambda_i + \lambda_j)}{2}\right] GD_{ij}. \tag{4.20}$$

In comparison with (4.6) and (4.12), equations (4.15) and (4.16) convey more distinctly whether the chosen pool/bilateral mix and the bilateral tariffs π^b_{ij} are economically advantageous. For instance, in the case of a generator, the first term, $\hat{R}^p_{gi}$, in (4.15) indicates the revenue that would have been collected had all generation output been sold at the current pool nodal price, λ_i. The second term, $\hat{R}^b_{gi}$, which can be positive or negative, measures how well the pre-negotiated bilateral tariffs, π^b_{ij}, compare with the "average" nodal price, $(\lambda_i + \lambda_j)/2$. A negative value of $\hat{R}^b_{gi}$ is a signal to generator i that its bilateral agreements in terms of prices and amounts were not profitable, so that in the future it should re-evaluate its bilateral selling price or the amounts contracted.

Similarly, in equation (4.16) that depicts the total load expenses, the term $\hat{E}^p_{dj}$ indicates the amount paid by load j had all the power demand been bought from the pool at the current nodal price, λ_j. The second term, $\hat{E}^b_{dj}$, is analogous to $\hat{R}^p_{dj}$ of (4.15), but, in contrast with the generators, the loads seek to minimize this term and, if possible, to make it negative. Large positive values of $\hat{E}^p_{dj}$ indicate to a load j that its bilateral contracts are not beneficial and should be re-evaluated in future trades.

In addition, equations (4.6) and (4.12) could be expressed in yet another form as,

$$R_{gi} = \lambda_i P_{gi} + \sum_{j=1}^{n} (\pi_{ij}^b - \lambda_i) GD_{ij} + \sum_{j=1}^{n} \left(\frac{\lambda_j - \lambda_i}{2} \right) GD_{ij}, \tag{4.21}$$

and

$$E_{dj} = \lambda_j P_{dj} + \sum_{i=1}^{n} (\pi_{ij}^b - \lambda_j) GD_{ij} + \sum_{i=1}^{n} \left(\frac{\lambda_j - \lambda_i}{2} \right) GD_{ij}. \tag{4.22}$$

The first terms in (4.21) and (4.22) are equivalent to $\hat{R}_{gi}^p$ and $\hat{E}_{dj}^p$ in (4.15) and (4.16) respectively. The second terms allow for a direct comparison between the pre-agreed bilateral price and the nodal price at which power would be sold or bought if purchased through the pool. The third terms are the original power transfer payments.

4.3 Simulation Studies: Combined Pool/Bilateral Operation with Firm Bilateral Contracts

The system operation under the proposed combined pool/bilateral model of (3.8) is illustrated on the 5-bus network described in Appendix C. These studies reveal that firm bilateral trades can have a significant impact on the overall system operation, on nodal prices, on power transfer payments, and on the financial performance of the market participants. The results bring out the need for strict coordination between bilateral and pool trades.

Simulation Assumptions

To simplify the studies and their analysis, the bus voltage magnitudes of the transmission network are assumed fixed at one per unit by sufficient VAr sources. The pool demand and the bilateral contracts are considered inelastic and known to the SO. In addition, the bilateral contracts are physical instead of financial instruments, which means that generator i must inject GD_{ij} megawatts into bus i while the consumers at bus j must absorb the same level of power. According to the already discussed rules of this combined pool/bilateral model, the supply of losses and any congestion re-dispatch is solely provided by the pool.

Since the bilateral contract rates are private and confidential, for the purpose of these simulations, reasonable estimates are presumed for these quantities, namely that each generator charges the same amount to all its contracts and that this amount is equal to its marginal generation cost offer evaluated at its total bilateral output, that is,

$$\pi_{ij}^{b} = \frac{d\Theta_i(P_{gi}^{b})}{dP_{gi}}; \quad \forall j. \tag{4.23}$$

Another way to estimate the bilateral tariffs is through the expected value of the nodal price, or as the marginal price at its expected total output.

Simulation Results with Various Proportions of Pool/Bilateral Trading

To examine the effect of varying the relative levels of pool and bilateral trading (the pool/bilateral mix) on system operation and on the financial performance of the various market participants, four cases are simulated. The results also bring out some shortcomings of the proposed market model caused primarily by the firmness of the bilateral contracts.

The four studied simulated cases are with:

- no bilateral trades (Base case);
- bilateral contracts that do not affect the generation schedule (Case A);
- high level of bilateral trades that activate lower generation bilateral limits and cause "out of merit" operation but without transmission congestion (Case B);
- bilateral contracts that cause transmission congestion (Case C).

All four cases assume the same inelastic bus demand vector given by,

$$\mathbf{P}_d = [34 \;\; 85 \;\; 119 \;\; 323 \;\; 527]^T \quad \text{MW}, \tag{4.24}$$

with the matrix of bilateral trades defined as,

$$\mathbf{GD} = \rho \begin{bmatrix} 34 & 51 & 34 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW.} \tag{4.25}$$

The proportion of bilateral demand relative to the total demand is controlled through the parameter $\rho \in [0,1]$. For $\rho = 0$ all the demand defined in (4.24) is supplied though the pool, while at the opposite extreme, when $\rho = 1$, the loads are being supplied only through bilateral contracts. The pool part of the demand, $\mathbf{P}_d^p$, is equal to the difference between the vectors of total bus demands and the bilateral bus demands (defined in (3.1) and (3.3)),

$$\begin{aligned} \mathbf{P}_d^p &= \mathbf{P}_d - \mathbf{P}_d^b \\ &= \begin{bmatrix} 34 \\ 85 \\ 119 \\ 323 \\ 527 \end{bmatrix} - \rho \begin{bmatrix} 34 \\ 85 \\ 119 \\ 323 \\ 527 \end{bmatrix} \text{ MW.} \end{aligned} \tag{4.26}$$

The total system demand in all cases is 1088 MW.

Base case: No bilateral contracts

This case where all demands are supplied uniquely through the pool is given as a reference against which all other cases can be compared. In this case $\rho = 0$ and the vector of pool demand is thus equal to the vector of total demand,

$$\mathbf{P}_d^p = \mathbf{P}_d = \begin{bmatrix} 34 & 85 & 119 & 323 & 527 \end{bmatrix}^T \tag{4.27}$$

with the matrix of bilateral contracts being zero, $\mathbf{GD} = \mathbf{0}$.

The optimum dispatch solution given in Table 4-1 shows that no generation or transmission constraints are activated, and that the more expensive generators 4 and 5 are dispatched at their lower bounds of 0 MW.

The values of the power flows, as well as the levels of generation and nodal prices are also given in Figure 4-2.

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	34	85	119	323	527	1,088
P_d^b $[MW]$	0	0	0	0	0	0
P_g $[MW]$	383	485	268	0	0	1,136
P_g^p $[MW]$	383	485	268	0	0	1,136
P_g^b $[MW]$	0	0	0	0	0	0
$I\Theta$ $[\$/MWh]$	35.3	35.5	37.1	56.0	57.0	-
λ_i $[\$/MWh]$	35.3	35.5	37.1	38.1	41.3	-
π_g^b $[\$/MWh]$	30.4	28.8	30.4	-	-	-
$C_g = \Theta$ $[\$/h]$	10,987	14,208	8,928	400	400	34,923
R_g^p $[\$/h]$	13,520	17,217	9,943	0	0	40,680
R_g^b $[\$/h]$	0	0	0	0	0	0
$E^{bcl}/2$ $[\$/h]$	0	0	0	0	0	0
R_g $[\$/h]$	13,520	17,217	9,943	0	0	40,680
E_d^p $[\$/h]$	1,200	3,017	4,415	12,306	21,765	42,703
E_d^b $[\$/h]$	0	0	0	0	0	0
$E^{bcl}/2$ $[\$/h]$	0	0	0	0	0	0
E_d $[\$/h]$	1,200	3,017	4,415	12,306	21,765	42,703

Table 4-1. Case with no bilateral contracts

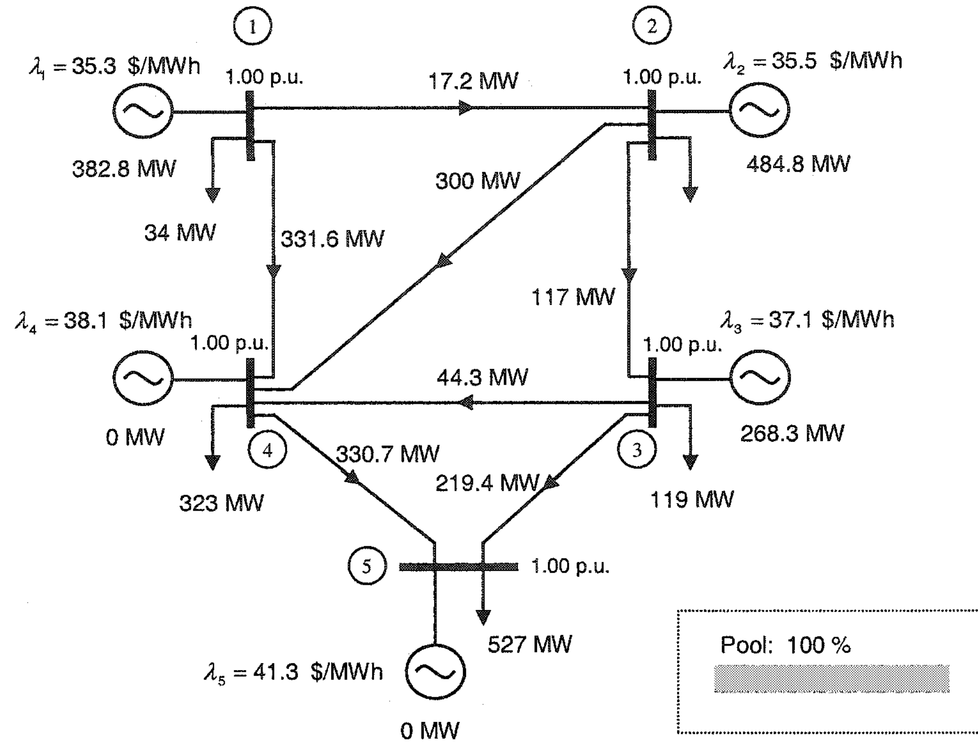

Figure 4-2. Base case: Line flows and nodal prices

Case A: Bilateral contracts that do not affect the generation dispatch

Here, 41.2 % of the demand is supplied from the pool, while the remaining load is supplied by the bilateral contracts,

$$\mathbf{GD} = \begin{bmatrix} 20 & 30 & 20 & 90 & 100 \\ 0 & 20 & 20 & 70 & 150 \\ 0 & 0 & 30 & 30 & 60 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW.} \tag{4.28}$$

At this level of pool/bilateral mix, the lower bound bilateral generation limits ($P_{gi} \geq P_{gi}^b$) are inactive and have no effect on the optimal power flow solution. The generation outputs are therefore equivalent to those of the Base case of Table 4-1. Accordingly, the line flows for this case A shown in Figure 4-3 are identical with the flows of the Base case (Figure 4-2). Additional simulations show that, for this bilateral matrix structure, the optimal dispatch is unaffected for any level of bilateral demand less than 950 MW, or 87% of the total demand.

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	14	35	49	133	217	448
P_d^b $[MW]$	20	50	70	190	310	640
P_g $[MW]$	383	485	268	0	0	1,136
P_g^p $[MW]$	123	225	148	0	0	496
P_g^b $[MW]$	260	260	120	0	0	640
$I\Theta$ $[\$/MWh]$	35.3	35.5	37.1	56.0	57.0	-
λ $[\$/MWh]$	35.3	35.5	37.1	38.1	41.3	-
π_g^b $[\$/MWh]$	30.4	28.8	30.4	-	-	-
$C_g = \Theta$ $[\$/h]$	10,987	14,208	8,928	400	400	34,923
R_g^p $[\$/h]$	4,337	7,992	5,499	0	0	17,828
R_g^b $[\$/h]$	7,904	7,488	3,648	0	0	19,040
$E^{bcl}/2$ $[\$/h]$	449	539	143	0	0	1,132
R_g $[\$/h]$	11,792	14,940	9,004	0	0	35,736
$\hat{R}_g^p$ $[\$/h]$	13,518	17,234	9,948	0	0	40,700
$\hat{R}_g^b$ $[\$/h]$	-1,726	-2,293	-944	0	0	-4,964
E_d^p $[\$/h]$	494	1,244	1,817	5,073	8,967	17,595
E_d^b $[\$/h]$	608	1,488	2,096	5,664	9,184	19,040
$E^{bcl}/2$ $[\$/h]$	0	3	33	234	861	1,132
E_d $[\$/h]$	1,102	2,736	3,946	10,971	19,012	37,766
$\hat{E}_d^p$ $[\$/h]$	1,201	3,021	4,412	12,319	21,777	42,730
$\hat{E}_d^b$ $[\$/h]$	-98	-286	-466	-1,349	-2,765	-4,964

Table 4-2. Case A: $P_d^b = 58.8\%$; $P_d^p = 41.2\%$; No active bilateral generation or transmission limits

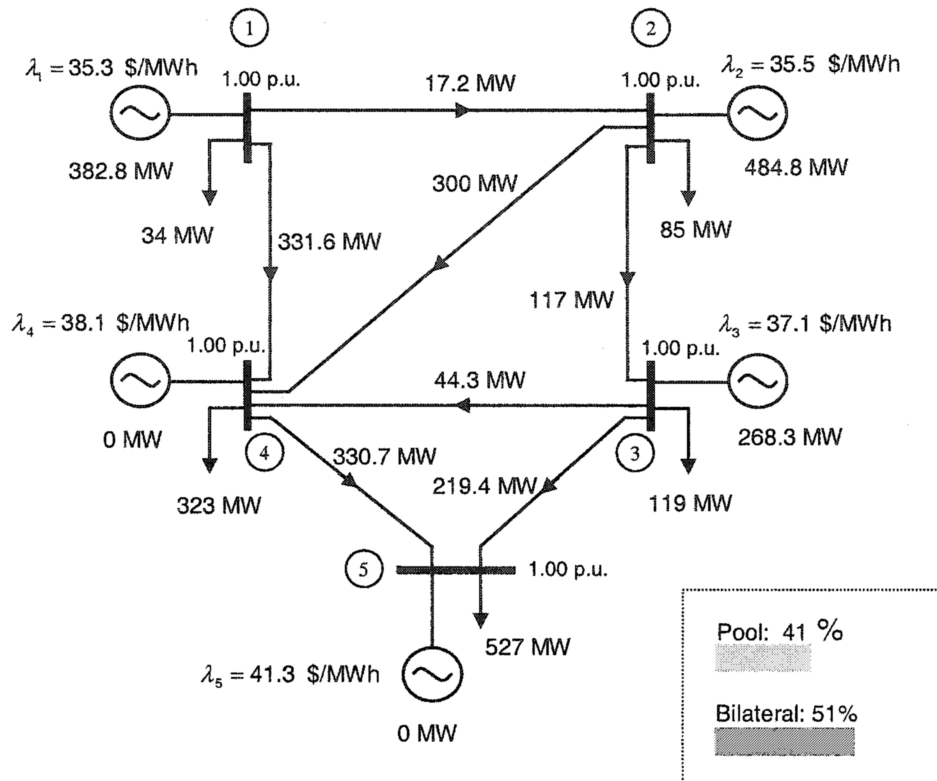

Figure 4-3. Case A: Line flows and nodal prices

As all system losses are supplied by the pool, the total bilateral generation and the total bilateral demand are equal. The total losses can be easily evaluated as the difference between the total generation output (1136 MW) and the total demand (1088 MW).

Although the generation dispatch is the same, from the financial perspective Case A differs from the Base case. First, the presence of bilateral contracts in case A results in non-zero power transfer payments, E_{ij}^{bcl}, with the power transfer rates being,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 0.2 & 1.8 & 2.8 & 6 \\ -0.2 & 0 & 1.6 & 2.6 & 5.8 \\ -1.8 & -1.6 & 0 & 1 & 4.2 \\ -2.8 & -2.6 & -1 & 0 & 3.2 \\ -6 & -5.8 & -4.2 & -3.2 & 0 \end{bmatrix} \text{\$/MWh.} \qquad (4.29)$$

Recalling that the negative values of power transfer tariffs indicate counter-flows, the negative values in (4.29) identify the points of the network between which bilateral trades may be beneficial for the trading partners, as well as for the overall system operation. For example, a contract between a generator at bus 5 and a load at bus 2 would induce such a counter-flow, as the corresponding value of the power transfer tariff is $(\lambda_2 - \lambda_5) = -5.8$ \$/MWh. The scheduling of bilateral contract GD_{52}, however, would create an increase in this value, but as long as the scheduled amount of GD_{52} is sufficiently small as not to reverse the direction of network power flows, the value of $(\lambda_2 - \lambda_5)$ will remain negative.

Also, note that local bilateral contracts do not have to pay anything for the power transfer, as they are not contributing to system losses or congestion. For example the power transfer payments of load 1 are zero, $E_{d1}^{bcl} = 0$, as it has bilateral contracts only with the local generator.

As expected, the total generation bilateral revenues (19,040 \$/h) are equal to the total bilateral load payments. On the other hand, the total generation revenues collected from the pool components are $\sum_{i=1}^{n} R_{gi}^{p} = 17{,}828$ \$/h, while the total pool load payments, $\sum_{j=1}^{n} E_{dj}^{p}$, are slightly lower at 17,595 \$/h. This difference (233 \$/h) can be explained by the fact that the pool load payments do not include charges for the losses created by the bilateral contracts. These charges are covered by the power transfer payments to the pool, $E_{ij}^{bcl}/2$, in this case, 1,132 \$/h, for both loads and generators. Therefore, out of the 2,264 \$/h, paid to the pool for power transfers by all contracts, 233 \$/h are used to pay the generators for their ancillary service support of the bilateral trades, while the rest (2,031 \$/h) remains with the SO as merchandising surplus. This surplus is used to reduce the network use payments.

Furthermore, by comparing the various performance measures in case A, given in Table 4-2, with those of the Base case (Table 4-1), one can conclude that, overall, generators 1, 2 and 3 are now economically worse off. In comparison, the loads at the same buses are better off because their total payments have decreased. Note that the same conclusion is reached when comparing the values of total generator revenues, R_{gi}, with the revenue $\hat{R}_{gi}^{p}$, that reveals what generator i would collect had its entire output been sold to the pool, as defined by (4.17). The difference between these two values, as defined by (4.15), gives $\hat{R}^b_{gi}$, which is in this case negative for all the generators. This is a signal to the generators that they would be better off selling to the pool and that they should re-evaluate their bilateral agreements. The same conclusion regarding the tariffs stems from the second term of equation (4.21) that compares nodal and bilateral prices. As Table 4-1 indicates, for all three generators the nodal prices, λ_i, are higher than the bilateral tariffs, π^b_{ij}, which also means that the bilateral trades chosen are beneficial for the loads, as they are paying less than if all of the demand had been purchased through the pool. This is also reflected in the values of $\hat{E}^p_{dj}$ and $\hat{E}^b_{dj}$, which are the corresponding measures for the loads defined by equation (4.16). In contrast to the generators whose aim is to maximize the value of $\hat{R}^b_{gi}$, the loads wish to minimize $\hat{E}^b_{dj}$. In this case A, all the loads were clearly successful, as the values of $\hat{E}^b_{dj}$ are negative.

Finally, the net bilateral rates of individual bilateral contracts seen by generators, $\hat{\pi}^b_{gij}$, and loads, $\hat{\pi}^b_{dij}$, are calculated from (4.5) and (4.11) respectively, and given in Table 4-3. Comparison between these prices and the corresponding nodal prices, λ_i, of Table 4-2 show that in this case the net bilateral rates of both generators and load are below nodal prices, and thus bilateral trades are beneficial for the loads but not for the generators.

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$
bus # of selling generator	1	30.4	30.4	30.3	30.5	29.5	31.3	29	31.8	27.4	33.4
	2	—	—	28.8	28.8	28	29.6	27.5	30.1	25.9	31.7
	3	—	—	—	—	30.4	30.4	29.9	30.9	28.3	32.5

Table 4-3. Case A: Net bilateral rates seen by generators and loads

Case B: "Out of Merit" operation due to active lower bilateral generation limits

Here in case B, the proportion of bilateral demand has been gradually increased, with a corresponding decrease in the pool demand so as to maintain the total demand at each bus constant. The total bilateral demand in this case is 992 MW, which is 91.2% of the total, with the bilateral contract matrix defined as,

$$\mathbf{GD} = \begin{bmatrix} 31 & 46.5 & 31 & 139.5 & 155 \\ 0 & 31 & 31 & 108.5 & 232.5 \\ 0 & 0 & 46.5 & 46.5 & 93 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{MW.} \tag{4.30}$$

The remaining load (96 MW) is supplied thorough pool purchases,

$$\mathbf{P}_d^p = \begin{bmatrix} 3 & 7.5 & 10.5 & 28.5 & 46.5 \end{bmatrix}^T \tag{4.31}$$

The results of the optimum dispatch in Table 4-4 indicate that generator 1 is "out of merit" and is forced to operate at the lower bound of $P_{g1} = P_{g1}^b = 403$ MW as defined by its bilateral contracts. This condition does not, however, result in transmission congestion, as shown in Figure 4-4. Moreover, the nodal price differences,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 0.3 & 1.9 & 2.9 & 6.1 \\ -0.3 & 0 & 1.5 & 2.5 & 5.7 \\ -1.9 & -1.5 & 0 & 1 & 4.2 \\ -2.9 & -2.5 & -1 & 0 & 3.2 \\ -6.1 & -5.7 & -4.2 & -3.2 & 0 \end{bmatrix} \text{\$/MWh} \tag{4.32}$$

are relatively low and similar to those in case A. In both cases A and B, the nodal price differences are due solely to transmission losses. As for the power transfer payments, E_{ij}^{bcl}, they have gone up in case B, even though this increase is due mainly to the higher levels of bilateral demand (as the power transfer rates, $\lambda_j - \lambda_i$, remain practically unchanged).

It can also be observed in case B that the total generation cost is slightly higher (34,936 \$/h) than in case A (34,923 \$/h). This is expected since the active bilateral limit creates an "out of merit" generation dispatch that is necessarily more costly. Also, the incremental cost of generator 1 (IC=36.1 \$/MWh) is just above the nodal price at bus 1 (λ_1=34.8 \$/MWh), which is consistent with the fact that this generator operates at a lower limit.

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	3	7.5	10.5	28.5	46.5	96
P_d^b $[MW]$	31	77.5	108.5	294.5	480.5	992
P_g $[MW]$	403	473	261	0	0	1,136
P_g^b $[MW]$	403	403	186	0	0	992
$I\Theta$ $[\$/MWh]$	36.1	35.2	36.7	56.0	57.0	-
λ $[\$/MWh]$	34.8	35.2	36.7	37.7	40.9	-
π_g^b $[\$/MWh]$	36.1	33.1	33.4	-	-	-
$C_g = \Theta$ $[\$/h]$	11,708	13,779	8,649	400	400	34,936
R_g^p $[\$/h]$	0	2,453	2,746	0	0	5,199
R_g^b $[\$/h]$	14,556	13,335	6,207	0	0	34,098
$E^{bcl}/2$ $[\$/h]$	708	825	216	0	0	1,748
R_g $[\$/h]$	13,849	14,964	8,737	0	0	37,549
$\hat{R}_g^p$ $[\$/h]$	14,038	16,631	9,579	0	0	40,248
$\hat{R}_g^b$ $[\$/h]$	-189	-1,668	-842	0	0	-2,698
E_d^p $[\$/h]$	105	264	386	1,075	1,901	3,730
E_d^b $[\$/h]$	1,120	2,705	3,697	10,181	16,395	34,098
$E^{bcl}/2$ $[\$/h]$	0	8	54	361	1,325	1,748
E_d $[\$/h]$	1,224	2,977	4,136	11,617	19,622	39,577
$\hat{E}_d^p$ $[\$/h]$	1,184	2,990	4,371	12,182	21,546	42,275
$\hat{E}_d^b$ $[\$/h]$	40	-13	-235	-565	-1,925	-2,698

Table 4-4. Case B: $P_d^b = 91.2\%$; $P_d^p = 8.8\%$; Generator 1 is at bilateral contract lower limit, $P_{g_1}^{\min} = 403\ MW$; No transmission congestion.

The level of generation 1 in case B increases while the remaining generators decrease their output when compared to case A. The same comparison shows that the nodal prices are slightly lower in case B. This result is interesting and consistent with the economics of the problem since lower nodal prices are an incentive for increased pool consumption. This signal would tend to reduce bilateral contracts and return the system to "in-merit" operation.

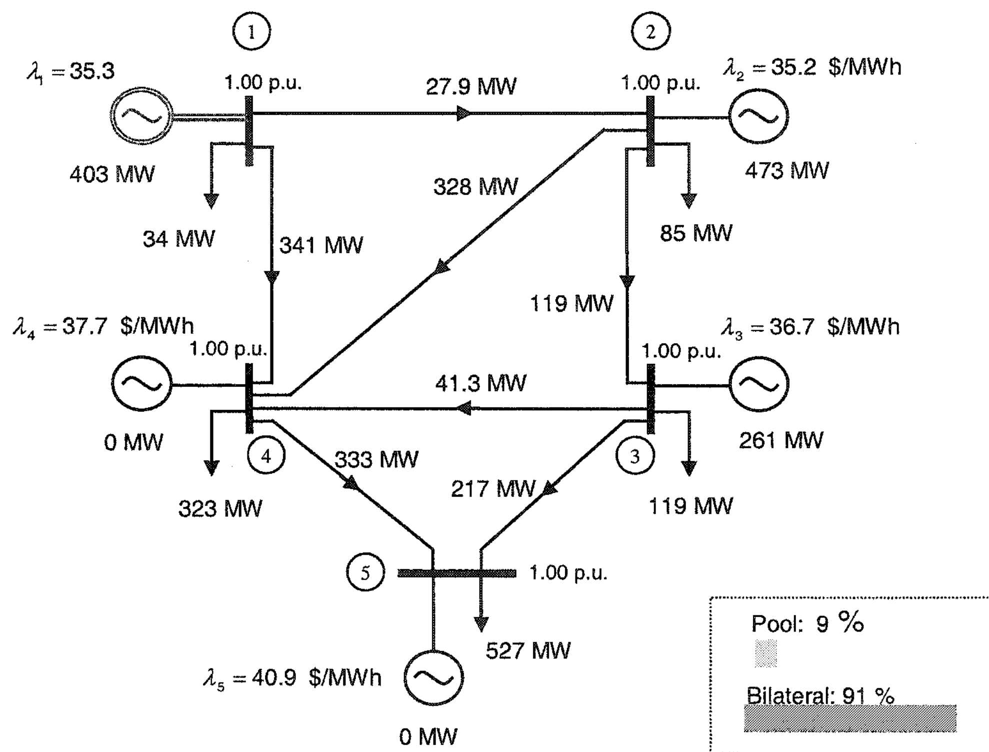

Figure 4-4. Case B: Line flows and nodal prices

Which market participants benefit the most from the higher relative bilateral demand and correspondingly higher bilateral tariffs of case B?

It is clear from Table 4-4 that the generators collect higher revenues (a total of 37,549 \$/h for case B versus 35,736 \$/h for case A). Moreover, since the generation costs are nearly the same in the two cases, the generator profits also increase. From the point of view of the loads, in case B they are worse off than in case A, their total payments increasing from 37,766 \$/h to 39,577 \$/h. Nevertheless, since the performance measures,

$\hat{R}_g^b$ and $\hat{E}_d^b$, are mainly negative, these indicate that the loads are still better off in case B than if they had been supplied entirely by the pool.

Considering the differences between the nodal prices, λ_j, of Table 4-4 and the net bilateral rates seen by generators, $\hat{\pi}_{gij}^b$, given in Table 4-5, only generator 1 has secured better bilateral rates for contracts GD_{11} and GD_{12}. As for the loads, Table 4-5 indicates that for most trades their net bilateral rates are below the nodal prices. The exception are the bilateral agreements which loads 1, 2 and 3 have with generator 1, which are more expensive then if they had purchased this power from the pool.

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}_{gij}^b$	$\hat{\pi}_{dij}^b$	$\hat{\pi}_{gij}^b$	$\hat{\pi}_{dij}^b$	$\hat{\pi}_{gij}^b$	$\hat{\pi}_{dij}^b$	$\hat{\pi}_{gij}^b$	$\hat{\pi}_{dij}^b$	$\hat{\pi}_{gij}^b$	$\hat{\pi}_{dij}^b$
bus # of selling generator	1	36.1	36.1	36	36.2	35.2	37	34.7	37.5	33.1	39.1
	2	—	—	33.1	33.1	32.3	33.9	31.8	34.4	30.2	36
	3	—	—	—	—	33.4	33.4	32.9	33.9	31.3	35.5

Table 4-5. Case B: Net bilateral rates seen by generators and loads

Case C: Congested Operation

As the bilateral demand increases (while the pool demand declines), not only can some generators be forced to operate at their lower bilateral contract levels, but transmission congestion may also appear. Table 4-6 presents the optimization results of case C where the total load (1088 MW) is supplied by bilateral contracts only, with the matrix of bilateral contracts defined as,

$$\mathbf{GD} = \begin{bmatrix} 34 & 51 & 34 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{MW.} \tag{4.33}$$

With 100% bilateral demand, the sole responsibility of the pool is to generate transmission losses as well as to manage transmission congestion, if any.

	Bus 1	***Bus 2***	***Bus 3***	***Bus 4***	***Bus 5***	**Sum**
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	0	0	0	0	0	0
P_d^b $[MW]$	34	85	119	323	527	1,088
P_g $[MW]$	442	442	224	28	0	1,137
P_g^b $[MW]$	442	442	204	0	0	1,088
$I\Theta$ $[\$/MWh]$	37.7	34.3	35.1	57.1	57.0	-
λ $[\$/MWh]$	-65.3	9.1	35.1	57.1	54.6	-
π_g^b $[\$/MWh]$	37.7	34.3	34.2	-	-	-
$C_g = \Theta$ $[\$/h]$	13,147	12,712	7,343	2,004	400	35,606
R_g^p $[\$/h]$	0	0	716	1,620	0	2,335
R_g^b $[\$/h]$	16,655	15,143	6,973	0	0	38,770
$E^{bcl}/2$ $[\$/h]$	23,168	9,098	1,558	0	0	33,824
R_g $[\$/h]$	-6,514	6,045	6,131	1,620	0	7,282
$\hat{R}_g^p$ $[\$/h]$	-28,872	4,035	7,875	1,620	0	-15,342
$\hat{R}_g^b$ $[\$/h]$	22,358	2,010	-1,745	0	0	22,624
E_d^p $[\$/h]$	0	0	0	0	0	0
E_d^b $[\$/h]$	1,281	3,087	4,189	11,585	18,628	38,770
$E^{bcl}/2$ $[\$/h]$	0	1,898	2,149	12,786	16,991	33,824
E_d $[\$/h]$	1,281	4,985	6,338	24,371	35,619	72,594
$\hat{E}_d^p$ $[\$/h]$	-2,221	776	4,177	18,454	28,784	49,970
$\hat{E}_d^b$ $[\$/h]$	3,502	4,209	2,161	5,917	6,834	22,624

Table 4-6. Case C: $P_d^b = 100\%$; $P_d^p = 0\%$; Generators 1 and 2 are at their lower bilateral limit, and line 1-4 is congested.

In this particular case, at the optimum dispatch, the scheduled bilateral contracts congest line 1-2 at its limit of 355 MW (Figure 4-5), while generators 1 and 2 are required to operate at their bilateral contract lower bound of $P_{g1}^b = P_{g2}^b = 442\,MW$.

Because of congestion, the pool is obliged to buy power from one of the expensive generators ($P_{g4} = 28\,\text{MW}$), which increases the total generation cost by about 0.2%. As shown in Figure 4-5, this change is not as significant as that observed in the nodal prices and their differences, with the latter now being,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 74.4 & 100.4 & 122.4 & 119.9 \\ -74.4 & 0 & 26 & 48 & 45.5 \\ -100.4 & -26 & 0 & 22 & 19.5 \\ -122.4 & -42 & -16 & 0 & 3.5 \\ -119.9 & -45.5 & -19.5 & -3.5 & 0 \end{bmatrix} \text{MW.} \qquad (4.34)$$

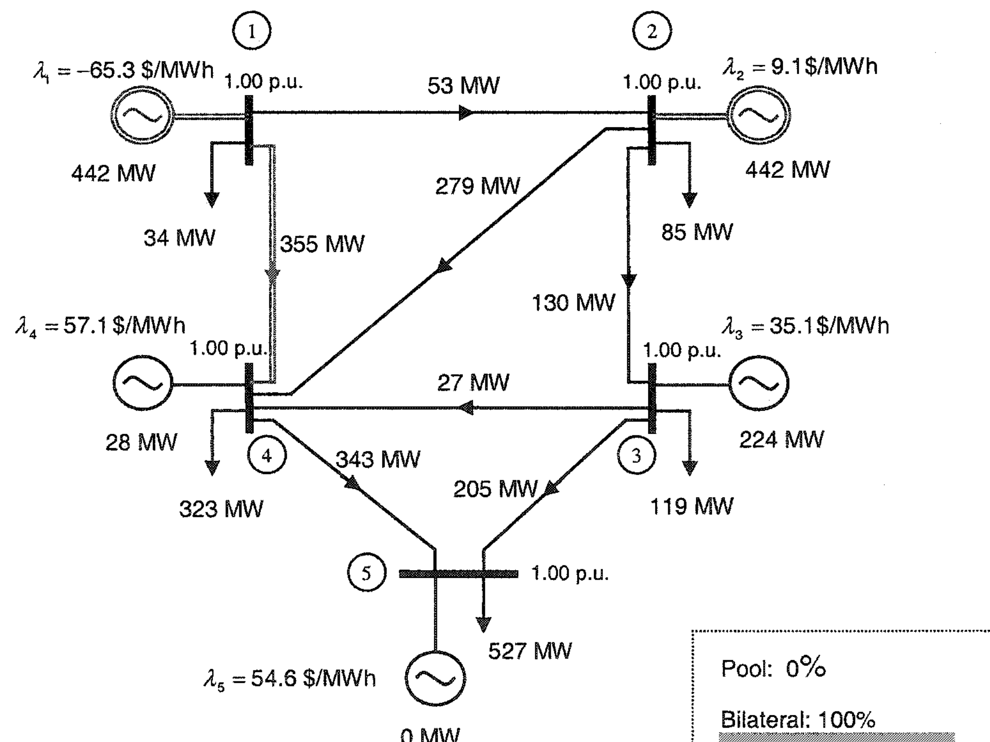

Figure 4-5. Case C: Line flows and nodal prices

It is interesting that the nodal price at bus 1 as seen in Table 4-6 is negative (-65.3 \$/MWh), which means that a load at that bus would get paid if it purchased power from the pool. This is a very strong incentive for the consumer at that bus to decrease its bilateral contracts and buy more from the pool. Such a change in the pool/bilateral mix will cause the price at bus 1 to increase, thus reducing the gap between this price and the prices at other network locations.

As this case C shows, the effect of 100% bilateral load supply on the revenues and payments is considerable. For example, all generators have revenues below their costs and operate at a loss. In the case of generator 1, its revenue is negative (that is it has to pay the pool for power transfer more than it earns from its bilateral sales). For example, the marginal rate to transfer power from bus 1 to bus 2 increased from 0.3 \$/MWh for case B, to 74.4\$/MWh in case C. For some bilateral trades, the power transfer prices from equation (4.34) are far above the bilateral tariffs from Table 4-6, indicating that such trades are unreasonable. As for the loads, they also suffer in case C by paying extremely high power transfer fees on top of the bilateral payments.

The main reason for the poor financial results is a substantial change in the power transfer rates ($\lambda_j - \lambda_i$). As bilateral trades are not allowed to buy financial transmission rights, they are faced with the full impact of high congestion costs. The view of this thesis is that a bad pool/bilateral mix should not be concealed behind hedging instruments like financial transmission rights that do not encourage efficient planning of the pool/bilateral mix. On the other hand, high power transfer rates encourage efficient planning of the pool/bilateral mix to account for network limits.

Although generators 1 and 2 have beneficial bilateral tariffs, π_g^b, the very high power transfer payments have wiped out that profitability. The differences between the net bilateral rates of generators, $\hat{\pi}_{gij}^b$, and loads, $\hat{\pi}_{dij}^b$, given in Table 4-7 and the nodal prices, of Table 4-6 also illustrate that heavy congestion has created an unbalanced and unbeneficial situation for most bilateral parties. Considering the generators, in most of their trades the net bilateral rate is significantly lower than the corresponding nodal price. Even worse, for generator 1, the net bilateral rates of its bilateral agreements GD_{13}, GD_{14} and GD_{15} become negative, with the respective values of $\hat{\pi}_{g13}^b = -12.5$, $\hat{\pi}_{g14}^b = -23.5$ and

$\hat{\pi}^b_{g15} = -22.3$ \$/MWh. As for the loads, most of net bilateral rates are considerably above the nodal prices, with the exception of bilateral contract GD_{33} which is local and is thus unaffected by transmission congestion. Also, all the contracts of generator 3 are beneficial for the loads as their net bilateral rates are less that the corresponding nodal prices. The unprofitable net rates encourage market participants to reduce the level of some bilateral trades and thus move the system towards a more balanced and efficient operation.

Finally, in this case C the merchandising surplus that remains after the SO pays the generators is very high of 65,312 \$/h.

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$
bus # of selling generator	1	37.7	37.7	0.5	74.9	-12.5	87.9	-23.5	99	-22.3	97.6
	2	—	—	34.3	34.3	21.3	47.3	10.3	58.3	11.5	57
	3	—	—	—	—	34.2	34.2	23.2	45.2	24.4	43.9

Table 4-7. Case C: Net bilateral rates seen by generators and loads

4.4 Difficulties Associated with Combined Pool/Bilateral Trading with Form Bilateral Contracts

The four cases presented demonstrate that the combined pool/bilateral model could be beneficial for market participants, as it offers them the freedom to participate simultaneously in two types of trading. Simulation results indicate that the financial performance measures proposed provide adequate signals to the bilateral parties to incite them to enter into bilateral agreements only after careful planning so as to avoid poor market outcomes, such as "out of merit" operation and transmission congestion. Although good bilateral contract planning is essential, this is not a trivial task, as it is difficult to predict a mix of pool/bilateral commitments at the time when bilateral contracts are being individually negotiated.

In order to lessen the consequences of inefficient pool/bilateral mixes, two variations of the proposed market are examined in the next chapter. One establishes a curtailment procedure that permits the SO to modify the requested firm bilateral contracts at the time of the optimum dispatch. Another allows both curtailable firm and non-firm contracts to co-exist.

Chapter 5.

Curtailment of Firm and Non-Curtailment of Non-Firm Contracts under Locational Marginal Pricing

The analysis of the combined pool/bilateral electricity market with firm bilateral contracts proposed in the previous chapter revealed that improperly planned high levels of bilateral trades may lead to poor economic performance for most participants. This is due to the resulting "out of merit" operation and line congestion that bring about high nodal price differences and associated high power transfer payments.

The full scope of the mutual influences between the pool and bilateral trades is however revealed only *ex-post*, after running the combined optimal power flow market clearing procedure. Since the planning and coordination of future pool and bilateral trades is a difficult task due to uncertainty in predicting the behaviour of other market participants, this chapter proposes an extension of the original combined pool/bilateral model [90]. This extended model provides a hedging mechanism to protect the market participants against unexpected market conditions that would otherwise result in high nodal prices and power transfer costs. In essence, this hedging device allows traders to coordinate their pool/bilateral mix ahead of time (or *ex-ante*), without the need to predict competing trades, while still maintaining a degree of independence in the negotiation of bilateral agreements.

The extended market model contains two forms of *ex-ante* pool/bilateral mix coordination. In one form, the owners of the firm bilateral trades may relinquish their firm rights to trade bilaterally, allowing the SO to modify their bilateral contracts downwards, if needed, for a curtailment price submitted by the owners of the firm contracts. Such firm bilateral contract curtailment is implemented by the SO only at the time of market clearing and only if this action reduces congestion and is economically advantageous in a system-wide sense. Any bilateral contract curtailment must be replaced by an equivalent amount supplied by the pool generation and charged at the pool nodal prices.

The second form of *ex-ante* pool/bilateral mix coordination to lessen the incidence and impact of transmission congestion is to allow both firm as well as non-firm bilateral contracts to co-exist. In contrast with the firm contracts that are pre-approved and possess a firm right to transfer a given amount of power, non-firm contracts are not assured the right to transfer power and are subject to curtailment by the SO without compensation. Non-firm contracts may enhance their chances to be scheduled with partial or no curtailment by submitting non-curtailment bids, that is, by promising to pay for the right to transfer power at a specified rate.

The market clearing process in the extended combined pool/bilateral model proposed here is again based on a one-step optimization procedure that concurrently dispatches generation, satisfies all operational constraints, and implements bilateral contracts curtailments if necessary. This differs from other proposals that use a two-step procedure [65-67], where the first step establishes a preferred generation schedule, and the second conducts loss allocation and congestion management while keeping close to the preferred bilateral schedule. Two–step methods claim to be more transparent, but they are less economically efficient and may even lead to infeasibility when implemented in a real system.

In [68] and [67], market participants that wish to avoid curtailment accept to pay extra by submitting "willingness to pay" bids. The pool then coordinates the level of curtailment and generation that minimizes the deviation from the approved transactions. This objective function also differs from the one proposed here where the goal is always to minimize cost or maximize social welfare. It is argued here that a SO should not dispatch power so as to match a set of privately negotiated bilateral contracts as closely as possible, since this objective may not be in the best interests of society as a whole, including the bilateral parties themselves.

In the zonal congestion management of California's original market [65, 66], voluntary incremental and decremental adjustments bids from generators and loads are used in the second optimization step to adjust the schedule so as to meet the load, while minimizing the total cost of these adjustments. Two-step procedures like this have been shown to be less efficient and lead to cross-subsidies [82].

This chapter is organized in the following manner. First, firm and non-firm contracts and their corresponding curtailment offers and non-curtailment bids are defined. These are then used to modify the original combined pool/bilateral model and to formulate the extended optimal power flow procedure. Then, the financial performance measures defined in Chapter 3 are applied to evaluate the system behaviour as well as the technical and financial performance of all traders under this new market model. A number of simulations are carried out to illustrate how the additional bilateral contract flexibility in the extended model allows the SO to reduce or eliminate congestion and "out of merit" operation while maximizing social welfare to the benefit of all the trading partners.

5.1 Extended Combined Pool/Bilateral Operation

5.1.1 Firm and Non-Firm Bilateral Contracts

In this extended model, in addition to the pool demand, two types of bilateral contracts are allowed to co-exist. The first are *firm* contracts that have obtained ahead of time the right to be scheduled and to transfer a specified amount of power. The second type are *non-firm* bilateral contracts whose dispatch is not guaranteed and are subject to curtailment if required by the SO to meet all system constraints and to minimize generation cost. These two types of contracts can be regarded as "non-recallable" and "recallable", as defined by NERC [41].

As originally defined, a firm contract can be reduced only in emergency situations, but not to improve system economic performance. Under current practices, in an emergency, bilateral parties with firm contracts do not receive any compensation for unfulfilled transmission obligations. Since emergency conditions occur very rarely, they are not analyzed in this thesis whose principal concern is the normal operation mode. The curtailment proposed in this chapter for firm bilateral contracts is implemented solely for the purpose of improving economic performance while respecting system security, and is a normal, non-emergency operation.

5.1.2 Offering Strategies of Firm and Bidding Strategies of Non-Firm Bilateral Agreements

To reconcile on the one hand the need for centralized coordination of the system operation, and at the same time to allow bilateral parties more influence over the financial outcomes of the market clearing procedure, it is proposed here that each firm and non-firm bilateral contract be allowed to submit a respective *curtailment offer* and *non-curtailment bid*. Moreover, as the strategy of each partner in a bilateral contract may be different, the selling generation and the purchasing load can submit a curtailment offer and a non-curtailment bid that are not necessarily equal.

For a firm contract, the curtailment offers from each party can be interpreted as requests for compensation in case of curtailment. In the case of non-firm agreements, non-curtailment bids reveal how much a contract is prepared to pay for non-curtailment.

If one or both partners in a firm contract do not wish to be curtailed, at least one partner must offer a high curtailment price. However, as high offers may prevent the SO from carrying out the necessary contract adjustments to reduce congestion, such offers must be used with care. As for non-curtailment bids, they are beneficial to non-firm bilateral contract parties only if the corresponding payments do not cut into their net bilateral revenue significantly.

It is interesting to note that bilateral parties could also use the proposed curtailment mechanisms to lessen the impact of unprofitable bilateral trades by cutting back the levels of bilateral trading actually scheduled. This situation may occur because bilateral agreements are usually long-term and the parties may not have predicted the pool price of power accurately. Thus, if the pre-agreed bilateral prices happen to deviate significantly from the pool price, one bilateral partner will be unsatisfied while the other partner will be satisfied. The unsatisfied partner may try to reduce the bilateral agreement by offering to curtail at a low or even at a negative price, in other words, this agent may even be willing to pay to be freed from the bilateral agreement. In comparison, the satisfied partner may counteract the former strategy by offering to curtail only at a very high price.

5.1.3 Acquiring Rights for Firm Agreements

The rights associated with a firm bilateral agreement can be acquired in two ways, *Purchased Firm Status (PFBS)* and *First-come-first-serve Firm Status (FFBS)*. The first is through an auction where the highest bidder wins and essentially buys a firm bilateral status. As shown in Appendix B, the PFBS auction is defined systematically though an optimization procedure similar to that of (3.8) that accounts for all system constraints including losses and transmission congestion. The auction gives firm status to all bidders if there is enough capacity, and if not, it gives firm status to the sub-set of bidders who place the highest combined worth on their requested bilateral contracts. The contracts that are assigned firm rights by the auction then pay to the SO an amount equal to the worth that they quoted.

Similarly to Financial Transmission Rights, the PFBS could be traded in a secondary market, however the owners of firm bilateral contracts always retain responsibility for the power transfer and associated power transfer payments. This differs significantly from FTR's whose owners are not necessarily responsible for the transfer of power and its cost. Unlike FTR's, under PFBS if the predicted power transfer payments are large, the PFBS can be traded back to the SO through curtailment offers as detailed later on in this chapter.

In the First-Come-First-Serve Firm Bilateral Status approach, the SO assigns firm bilateral status periodically and relatively frequently. This is done based on the transmission capacity available at the moment that the allocation procedure is performed, as discussed in Appendix B. All the bilateral contracts that have been previously awarded firm status remain intact, while the SO seeks to accommodate as much of the newly requested bilateral transactions sum as the current transmission capacity allows. In contrast to PFBS, under the FFBS all contracts are considered equal and typically do not pay anything for obtaining firm bilateral status.

5.1.4 Payments for Curtailed Firm Agreements

Contracts with Purchased Firm Bilateral Status are entitled to collect curtailment revenue from the SO if the scheduled contract is less than the approved contract. These rights to collect curtailment payments are called *Financial Curtailment Rights* (FCR).

In addition, if a firm contract is curtailed, the missing power must be matched by the pool and not by another contract. Furthermore, any curtailed power replaced by the pool is valued at the nodal price.

As the financial resources of the SO[18] may not be sufficient to cover the curtailment revenue owed to the firm bilateral parties, additional funds would have to be collected by the SO from all market participants. One way to collect such funds is in a pro-rata manner.

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[18] The sources of income of the SO are the payments for acquiring firm bilateral status plus any merchandising surplus due to transmission losses and congestion.

Contracts that acquire firm bilateral status on a First-Come-First-Served basis gain what is called *Free-of-Charge Curtailment Rights (FCCR).* Since, under this rule, firm bilateral contracts do not pay to gain firm status, they are not entitled to collect any money from the SO if they are curtailed. Nevertheless, firm contracts with FCCR can still submit curtailment offers as a mechanism to hedge against high congestion power transfer costs. In this case, the curtailment offers reflect the value that the bilateral parties place on amount of power curtailed. Note also that with FCCR's, the SO is released from the responsibility to collect sufficient funds to pay for curtailment obligations as is the case with FCR's. Also, participants are less likely to engage in gaming when there is no possibility to profit from curtailment.

The market clearing optimization problem has the same structure under both FCR's and FCCR's, and therefore the same solution scheme. In practice however the levels of the approved contracts and the curtailment offers, as well as the financial performances may differ. Numerical analyses of both methods are presented later in this chapter.

As for non-firm contracts, since they do not buy or acquire firm bilateral status, they do not collect any curtailment income, and thus the notions of FCR and FCCR discussed above are not applicable. In fact, non-firm contracts nearly always bid and pay some amount to the SO in order not to be curtailed.

5.2 A Mathematical Framework for Combined Pool/Bilateral Dispatch with Bilateral Curtailment and Non-Curtailment

The mathematical framework for the extended combined pool/bilateral operation requires new notation to distinguish between firm and non-firm contracts as well as to characterize the curtailment offers and the non-curtailment bids.

5.2.1 Notation and Definitions

Firm and Non-Firm Contracts

The firm contracts approved by the SO, and non-firm contracts requested by the bilateral parties are denoted by the matrices $\mathbf{GDF}^{app}$ and $\mathbf{GDNF}^{req}$ respectively, while their real scheduled values after curtailment are denoted by $\mathbf{GDF}$ and $\mathbf{GDNF}$. Thus, the total scheduled bilateral contract matrix is,

$$\mathbf{GD} = \mathbf{GDF} + \mathbf{GDNF}. \qquad (5.1)$$

Curtailment Offers and Non-Curtailment Bids

Under the extended model, generator i has the option to submit a curtailment offer price in \$/MWh, bf_{gij}, for the amount curtailed from each firm contract, $GDF_{ij}^{app} - GDF_{ij}$, and a non-curtailment bid price, bnf_{gij}, for the scheduled amount of each non-firm contract, $GDNF_{ij}$. Similarly, load j may submit two analogous offer and bid prices, bf_{dij} and bnf_{dij}.

Thus, if a firm contract is curtailed by the SO from GDF_{ij}^{app} to GDF_{ij}, the generating party is requesting a payment of $bf_{gij}\left(GDF_{ij}^{app} - GDF_{ij}\right)$, while the consuming party is requesting a payment of $bf_{dij}\left(GDF_{ij}^{app} - GDF_{ij}\right)$, for a total of $bf_{ij}\left(GDF_{ij}^{app} - GDF_{ij}\right)$, where,

$$bf_{ij} = bf_{gij} + bf_{dij}. \qquad (5.2)$$

On the other hand, the generating party of a non-firm contract that wishes to avoid or reduce the curtailment of its requested value, $GDNF_{ij}^{req}$, offers a payment of $bnf_{gij}\,GDNF_{ij}$ to the SO for the scheduled trade, $GDNF_{ij}$. The consuming party may also offer a similar payment of $bnf_{dij}\,GDNF_{ij}$, so that the total non-curtailment payment offered by a non-firm bilateral trade to the SO becomes $bnf_{ij}\,GDNF_{ij}$, with,

$$bnf_{ij} = bnf_{gij} + bnf_{dij} . \qquad (5.3)$$

In this thesis, the curtailment offer prices and the non-curtailment bid prices are modeled as constants, however more general non-linear prices can also be considered.

5.2.2 Scheduling or Market Clearing Procedure

The general formulation of the extended combined pool/bilateral dispatch with curtailment and non-curtailment options is,

$$\underset{\mathbf{P}_g,\mathbf{Q}_g,\mathbf{V},\boldsymbol{\delta},\mathbf{GDF},\mathbf{GDNF}}{Min} \quad \sum_{i=1}^{n} \Theta_{gi}(P_{gi}) + \sum_{i,j=1}^{n} bf_{ij}(GDF_{ij}^{app} - GDF_{ij}) - \sum_{i,j=1}^{n} bnf_{ij} \cdot GDNF_{ij} \qquad (5.4)$$

$$\text{s.t.} \quad (\mathbf{P}_g, \mathbf{Q}_g, \mathbf{V}, \boldsymbol{\delta}) \in S$$

$$0 \le GDF_{ij}^{\min} \le GDF_{ij} \le GDF_{ij}^{app}$$

$$0 \le GDNF_{ij} \le GDNF_{ij}^{req}$$

$$\mathbf{P}_g \ge \mathbf{P}_g^b = (\mathbf{GDF} + \mathbf{GDNF}) \cdot \mathbf{e}$$

Recall that, following the above market clearing procedure, the owners of the combined scheduled contracts, $\mathbf{GD} = \mathbf{GDF} + \mathbf{GDNF}$, have acquired a right as well as an obligation to transfer these amounts.

As defined in Chapter 3, the set S denotes the power system security region. The extended formulation in (5.4) differs from the basic one in (3.8) in two ways. First, the objective function has two additional terms, one to account for the total curtailment cost[19] of the firm contracts, $\sum_{i,j=1}^{n} bf_{ij}(GDF_{ij}^{app} - GDF_{ij})$, and the other for the total non-curtailment

[19] In the case of Purchased Firm Bilateral Status this term represents a real cost since it has to be paid to the owners of the firm contracts. In the case of First-Come-First-Serve Bilateral Status, this term represents the value that the owners of the firm contracts attach to the curtailments.

revenue of the non-firm contracts, $\sum_{i,j=1}^{n} bnf_{ij} \cdot GDNF_{ij}$. This term appears in the objective function with a negative sign since it is a payment by the non-firm contracts who wish to reduce their level of curtailment.

The extended model is also characterized by the addition of specified upper and lower limits on the scheduled firm and non-firm bilateral contracts, namely, $0 \leq GDF_{ij}^{\min} \leq GDF_{ij} \leq GDF_{ij}^{app}$ and $0 \leq GDNF_{ij} \leq GDNF_{ij}^{req}$, respectively. These reflect the increased flexibility of the actual scheduled bilateral commitments, both non-firm and firm.

As indicated in (5.4), the lower bounds on the generation outputs, P_{gi}^{b}, are as before dictated by the scheduled bilateral commitments, however these bounds are no longer fixed, but rather are variable limits that depend on the firm and non-firm scheduled contracts.

The solution of the optimization problem (5.4) (market clearing procedure) yields the scheduled generation output, $\mathbf{P}_g$, and the levels of the scheduled firm, $\mathbf{GDF}$, and non-firm, $\mathbf{GNDF}$, bilateral contracts. These, in turn, define the total firm and non-firm bilateral generation, $\mathbf{P}_g^b = \mathbf{GD} \cdot \mathbf{e}$, and the pool generation, $\mathbf{P}_g^p = \mathbf{P}_g - \mathbf{P}_g^b$, as well as the total bilateral and pool demands, respectively, $\mathbf{P}_d^b = \mathbf{GD}^T \cdot \mathbf{e}$, and $\mathbf{P}_d^p = \mathbf{P}_d - \mathbf{P}_d^b$. Since in this market model, the bilateral contracts cannot increase above their approved values and the total demand is inelastic, any curtailed bilateral demand must be substituted by an exact amount of pool demand. Thus, both pool and bilateral demands, $\mathbf{P}_d^p$ and $\mathbf{P}_d^b$ are no longer known in advance, but fluctuate according to the scheduled contracts, **GDF** and **GDNF**.

5.3 Financial Performance Measures

The pricing of the pool components and of the bilateral trades remains the same as the case without curtailment described in Chapter 4. Also, the ancillary services (losses and congestion re-dispatch) in support of all the bilateral trades are still priced at the nodal price differences between the nodes of injection and consumption. However, as shown next, the curtailment options may introduce additional sources of revenue and expenses.

5.3.1 Generator Revenues and Expenditures

Performance measures similar to those defined in Chapters 3 and 4 are now applied to the market equilibrium defined by (5.4). These measures are necessary to compare the economic merits of alternative trading strategies as defined by the curtailment offers and non-curtailment bids, which through (5.4) indirectly set the scheduled pool/bilateral mix.

The types of financial measures are divided first according to whether or not they depend on how the firm bilateral status is acquired (by purchasing it ahead of time or on a first-come-first-serve basis).

Those measures that are independent of how the firm status was acquired are, for generator i,

- Revenue from pool generation priced at $\pi_i^p = \lambda_i$,

$$R_{gi}^p = \lambda_i \cdot P_{gi}^p . \tag{5.5}$$

- Revenue from the bilateral contracts,

$$R_{gi}^b = \sum_{j=1}^{n} \pi_{ij}^{bf} GDF_{ij} + \sum_{j=1}^{n} \pi_{ij}^{bnf} GDNF_{ij} . \tag{5.6}$$

Here, π_{ij}^{nf} and π_{ij}^{bnf} are privately negotiated rates between the bilateral trading partners for the firm and non-firm contracts. Typically, non-firm contracts will have a lower rate than firm contracts.

The financial measures that depend on the type of firm bilateral status acquired are defined next. As indicated above there are two possibilities, *(1) Purchased Firm Bilateral Status with Financial Curtailment Rights*

Under this type of firm status, the expenditures associated with the bilateral contracts are,

- Firm status payment,

$$Ef_{ij}^{app} = bf_{ij}^{app} GDF_{ij}^{app}, \tag{5.7}$$

where bf_{ij}^{app} is the rate paid to the SO by the contract to acquire a purchased firm status for GDF_{ij}^{app}.

- Power transfer payment for the scheduled firm contract GDF_{ij},

$$Ef_{ij}^{bcl} = (\lambda_j - \lambda_i) GDF_{ij}. \tag{5.8}$$

- Power transfer payment for the scheduled non-firm contract $GDNF_{ij}$,

$$Enf_{ij}^{bcl} = (\lambda_j - \lambda_i) GDNF_{ij}. \tag{5.9}$$

Using the 50/50 split, the combined expenditure allocated to generator i for all of its contracts is,

$$E_{gi}^{bcl} = \frac{1}{2} \sum_{j=1}^{n} (Ef_{ij}^{app} + Ef_{ij}^{bcl} + Enf_{ij}^{bcl}). \tag{5.10}$$

The curtailment offers and the non-curtailment bids have an additional financial impact on the bilateral participants. When a contract curtailment occurs, this can become a source of revenue or an additional expense to the bidding parties depending on the sign of the bid, a negative bid by one of the parties in any contract implying that it wishes to be curtailed (because they would rather trade in the pool market). Thus, for generator i two additional financial measures are defined according to its curtailment offers and non-curtailment bids, bf_{gij} and bnf_{gij},

- Revenue from the SO for the curtailment of firm contracts,

$$R_{gi}^{f} = \sum_{j=1}^{n} bf_{gij} (GDF_{ij}^{app} - GDF_{ij}). \tag{5.11}$$

- Payment to the SO for the scheduled non-firm contracts,

$$E_{gi}^{nf} = \sum_{j=1}^{n} bnf_{gij} \cdot GDNF_{ij}. \tag{5.12}$$

The profitability of each bilateral trade can also be examined from the perspective of the net contract price seen by each generator. In the case of firm bilateral contracts, this price is under Purchased Firm Bilateral Status defined as,

$$\hat{\pi}_{gij}^{bf} = \pi_{ij}^{bf} - \frac{(\lambda_j - \lambda_i)}{2} + \frac{1}{2}\frac{bf_{ij}(GDF_{ij}^{req} - GDF_{ij}) - bf_{ij}^{app} GDF_{ij}^{app}}{GDF_{ij}}, \tag{5.13}$$

while for the non-firm contracts it is,

$$\hat{\pi}_{gij}^{bnf} = \pi_{ij}^{bnf} - \frac{(\lambda_j - \lambda_i)}{2} - \frac{bnf_{ij}}{2}. \tag{5.14}$$

Finally, the total net revenue of generator i is,

$$R_{gi} = R_{gi}^{p} + R_{gi}^{b} - E_{gi}^{bcl} + R_{gi}^{f} - E_{gi}^{nf}. \tag{5.15}$$

The generator profit is the difference between this revenue and the generation cost (keeping in mind that the true cost is known only to the generator),

$$pr_{gi} = R_{gi} - C_{gi}(P_{gi}). \tag{5.16}$$

(2) First-Come-First-Serve Firm Bilateral Status

Since under this rule there are no payments for obtaining firm bilateral status, the trading partners do not collect any revenue if curtailed. Recall that the firm contract curtailment offers bf_{gij} are used only for hedging purposes against high power transfer payments, the higher the offer the lower the likelihood that the firm contract will be curtailed.

The expenditures associated with bilateral contracts are therefore only for power transfer payments, which for both firm and non-firm contracts are,

- Power transfer payment for scheduled firm contract GDF_{ij},

$$Ef_{ij}^{bcl} = (\lambda_j - \lambda_i)GDF_{ij}\,. \tag{5.17}$$

- Power transfer payment for scheduled non-firm contract $GDNF_{ij}$,

$$Enf_{ij}^{bcl} = (\lambda_j - \lambda_i)GDNF_{ij}\,, \tag{5.18}$$

so that the combined expenditure allocated to generator i for all of its contracts is,

$$E_{gi}^{bcl} = \frac{1}{2}\sum_{j=1}^{n}(Ef_{ij}^{bcl} + Enf_{ij}^{bcl})\,. \tag{5.19}$$

As for the financial impact of the curtailment and non-curtailment bids, we have,

- Revenue from the SO for the curtailment of firm contracts, which as discussed above must be equal to zero,

$$R_{gi}^{f} = 0\,. \tag{5.20}$$

- Payment to the SO for the scheduled non-firm contracts,

$$E_{gi}^{nf} = \sum_{j=1}^{n} bnf_{gij} \cdot GDNF_{ij}\,. \tag{5.21}$$

The net bilateral rate of firm contracts seen by generator is in this case same as defined by (4.5), that is,

$$\hat{\pi}_{gij}^{bf} = \pi_{ij}^{bf} - \frac{\lambda_j - \lambda_i}{2} \tag{5.22}$$

while for the non-firm contracts it is the same as the net bilateral rate defined in (5.14) for the case with Purchased Firm Bilateral Status,

$$\hat{\pi}_{gij}^{bnf} = \pi_{ij}^{bnf} - \frac{(\lambda_j - \lambda_i)}{2} - \frac{bnf_{ij}}{2} \tag{5.23}$$

The total net revenue of generator i in this case of free firm status is,

$$R_{gi} = R_{gi}^{p} + R_{gi}^{b} - E_{gi}^{bcl} - E_{gi}^{nf}\,, \tag{5.24}$$

while the profit remains defined as,

$$pr_{gi} = R_{gi} - C_{gi}(P_{gi}). \tag{5.25}$$

5.3.2 Load Revenues and Expenditures

Using the same reasoning applied to the generators, analogous load performance measures can be defined for load j. The measures that reflect payments for energy are also independent of the manner in which firm bilateral status is acquired and include,

- Payments for the pool demand,

$$E_{dj}^{p} = \lambda_j \cdot P_{dj}^{p}. \tag{5.26}$$

- Payments for the privately negotiated bilateral contracts,

$$E_{dj}^{b} = \sum_{i=1}^{n} \pi_{ij}^{bf} GDF_{ij} + \sum_{i=1}^{n} \pi_{ij}^{bnf} GDNF_{ij}. \tag{5.27}$$

Again, two sets of additional measures are defined, depending on the way in which firm bilateral status is obtained.

(1) Purchased Firm Bilateral Status with Financial Curtailment Rights

The obligations of load j to the SO due to the transmission of scheduled contracts include payments for acquiring firm status as well as power transfer payments for scheduled firm and non-firm contracts. Since these payments are equally split between the contract parties, the expenditure of load j for all its contracts is,

$$E_{gi}^{bcl} = \frac{1}{2} \sum_{j=1}^{n} (Ef_{ij}^{app} + Ef_{ij}^{bcl} + Enf_{ij}^{bcl}), \tag{5.28}$$

where Ef_{ij}^{app}, Ef_{ij}^{bcl} and Enf_{ij}^{bcl} are defined by equations (5.7), (5.8), and (5.9).

Similarly to the generator, for the load the additional impact of the curtailment offer, bf_{dij}, and the non-curtailment bid, bnf_{dij}, is reflected in the following financial measures,

- Revenue from the SO for the curtailment of firm contracts,

$$R_{dj}^{f} = \sum_{i=1}^{n} bf_{dij}(GDF_{ij}^{app} - GDF_{ij}). \tag{5.29}$$

- Payment to the SO for the scheduled non-firm contracts,

$$E_{dj}^{nf} = \sum_{i=1}^{n} bnf_{dij} \cdot GDNF_{ij}. \tag{5.30}$$

The net bilateral rate of firm contract seen by load j is for the now defined as,

$$\hat{\pi}_{dij}^{f} = \pi_{ij}^{f} + \frac{(\lambda_j - \lambda_i)}{2} - \frac{1}{2}\frac{bf_{ij}(GDF_{ij}^{req} - GDF_{ij}) - bf_{ij}^{app} GDF_{ij}^{app}}{GDF_{ij}} \tag{5.31}$$

while for the non-firm contracts it is,

$$\hat{\pi}_{dij}^{bnf} = \pi_{ij}^{bnf} + \frac{(\lambda_j - \lambda_i)}{2} + \frac{bnf_{ij}}{2} \tag{5.32}$$

Finally, the total payments of the load j are,

$$E_{dj} = E_{dj}^{p} + E_{dj}^{b} + E_{dj}^{bcl} + E_{dj}^{nf} - R_{dj}^{f}, \tag{5.33}$$

with the profit being the difference between the benefit function and the total payments of (5.33),

$$pr_{dj} = B_{dj}(P_{dj}) - E_{dj}. \tag{5.34}$$

(2) First-Come-First-Serve Firm Bilateral Status

As with the generators, in this case there are no expenditures for acquiring firm bilateral status nor are there any revenues from curtailment of firm contracts.

In this case the total expenditure of load j associated with the power transfer payments for firm and non-firm contracts is defined as,

$$E_{dj}^{bcl} = \frac{1}{2}\sum_{i=1}^{n}(Ef_{ij}^{bcl} + Enf_{ij}^{bcl}). \tag{5.35}$$

As for the financial impact of curtailment and non-curtailment bids, we have,

- The revenue from the SO for the curtailment of firm contracts is zero,

$$R_{dj}^{f}=0. \tag{5.36}$$

➢ Payment to the SO for the scheduled non-firm contracts,

$$E_{dj}^{nf}=\sum_{i=1}^{n} bnf_{dij}\cdot GDNF_{ij}. \tag{5.37}$$

In this case, the net bilateral rates of firm contracts seen by load j are,

$$\hat{\pi}_{dij}^{nf}=\pi_{ij}^{nf}+\frac{(\lambda_j-\lambda_i)}{2}+\frac{bnf_{ij}}{2} \tag{5.38}$$

while the net bilateral rates of non-firm contracts remain the same as defined by (5.32).

Hence, the total payment of load j, in the case when there are no financial curtailment rights, is,

$$E_{dj}=E_{dj}^{p}+E_{dj}^{b}+E_{dj}^{bcl}+E_{dj}^{nf}, \tag{5.39}$$

and the profit is,

$$pr_{dj}=B_{dj}(P_{dj})-E_{dj}. \tag{5.40}$$

5.3.3 Merchandising Surplus

According to the way in which firm bilateral status is obtained, two different expressions for the merchandising surplus arise.

(1) MS with Purchased Firm Bilateral Status with Financial Curtailment Rights

From equations (3.20) and (5.5) - (5.39), the merchandising surplus is,

$$
\begin{aligned}
MS &= \sum_{j=1}^{n} E_{dj} - \sum_{i}^{n} R_{gi} \\
&= \sum_{j=1}^{n}\left(E_{dj}^{p} + E_{dj}^{b} + E_{dj}^{bcl} - R_{dj}^{f} + E_{dj}^{nf}\right) - \sum_{i=1}^{n}\left(R_{gi}^{p} + R_{gi}^{b} - E_{gi}^{bcl} + R_{gi}^{f} - E_{gi}^{nf}\right) \\
&= \sum_{i=1}^{n} \lambda_i (P_{di}^{p} - P_{gi}^{p}) \\
&+ \sum_{i,j=1}^{n} \left(\lambda_j - \lambda_i\right) \cdot GDF_{ij} + \sum_{i,j=1}^{n} bf_{ij}^{app} GDF_{ij}^{app} - \sum_{i,j=1}^{n} bf_{ij} \, (GDF_{ij}^{app} - GDF_{ij}) \\
&+ \sum_{i,j=1}^{n} \left(\lambda_j - \lambda_i\right) \cdot GDNF_{ij} + \sum_{i,j=1}^{n} bnf_{ij} \, GDNF_{ij}
\end{aligned}
\tag{5.41}
$$

This expression differs from that of equation (4.14) when only firm trades (without curtailment bids) are present. Even without non-firm contracts, the MS contains the additional terms, $\sum_{i,j=1}^{n} bf_{ij}^{app} \, GDF_{ij}^{app}$ and $\sum_{i,j=1}^{n} bf_{ij} \, (GDF_{ij}^{app} - GDF_{ij})$. The first denotes the SO income from the sales of firm bilateral status, while the latter is an expense defined by the SO payments to the firm bilateral contracts that are curtailed.

It is possible in this model, under unusual conditions of high congestion and correspondingly high curtailment of firm contracts to have a negative MS. However, the MS is normally greater than zero so in the long-term the SO would not go into debt. In the worse case, the SO would have to seek an extraordinary payment from all users to avoid a loss.

(2) MS with First-Come-First-Serve Firm Bilateral Status

In this case, the merchandising surplus is defined as,

$$
\begin{aligned}
MS &= \sum_{j=1}^{n} E_{dj} - \sum_{i=1}^{n} R_{gi} \\
&= \sum_{j=1}^{n} \left(E_{dj}^{p} + E_{dj}^{b} + E_{dj}^{bcl} + E_{dj}^{nf} \right) - \sum_{i=1}^{n} \left(R_{gi}^{p} + R_{gi}^{b} - E_{gi}^{bcl} - E_{gi}^{nf} \right) \\
&= \sum_{i=1}^{n} \lambda_i (P_{di}^{p} - P_{gi}^{p}) \qquad (5.42) \\
&+ \sum_{i,j=1}^{n} \left(\lambda_j - \lambda_i \right) \cdot GDF_{ij} \\
&+ \sum_{i,j=1}^{n} \left(\lambda_j - \lambda_i \right) \cdot GDNF_{ij} + \sum_{i,j=1}^{n} bnf_{ij} \, GDNF_{ij}
\end{aligned}
$$

Except for the revenue from power transfers of non-firm contracts and from the non-curtailment of non-firm contracts, the MS expression (5.42) would reduce to that of (4.14), which is always positive.

5.4 The Flow of Revenues and Payments

The flow of revenues and payments for generators and loads is illustrated in Figure 5-1 for the operation under Purchased Firm Bilateral Status with Financial Curtailment Rights, and in Figure 5-2 for the approach with First-Come-First-Serve Firm Free-of-Charge Curtailment Rights. The bilateral payments by the loads to the generators are shown as dotted lines to emphasize that they are privately negotiated and are not handled by the SO. The SO sees all other payments and revenues, such as the pool demand payments, the power transfer payments, the firm status fees (if applicable), as well as the non-curtailment payments of non-firm contracts as revenues. From these revenues, the SO has to disburse payments for the pool generation revenues and in the case of operation with Financial Curtailment Rights payments for the curtailment of firm bilateral agreements.

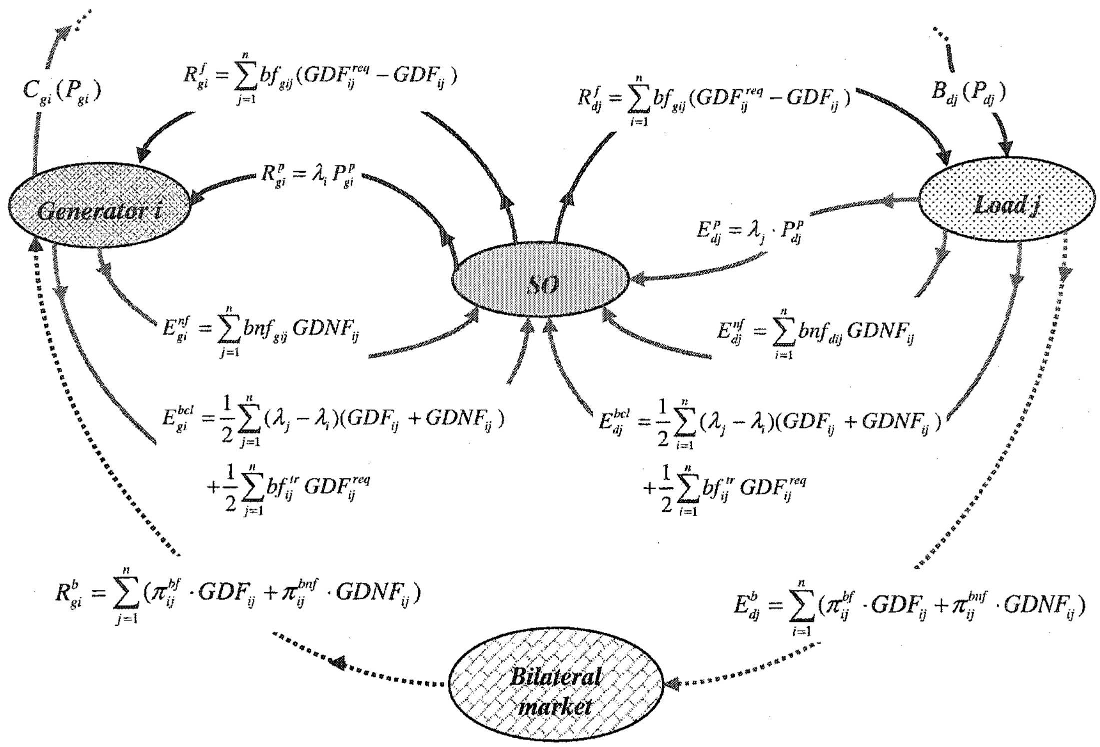

Figure 5-1. Financial transaction for operation with Financial Curtailment Rights

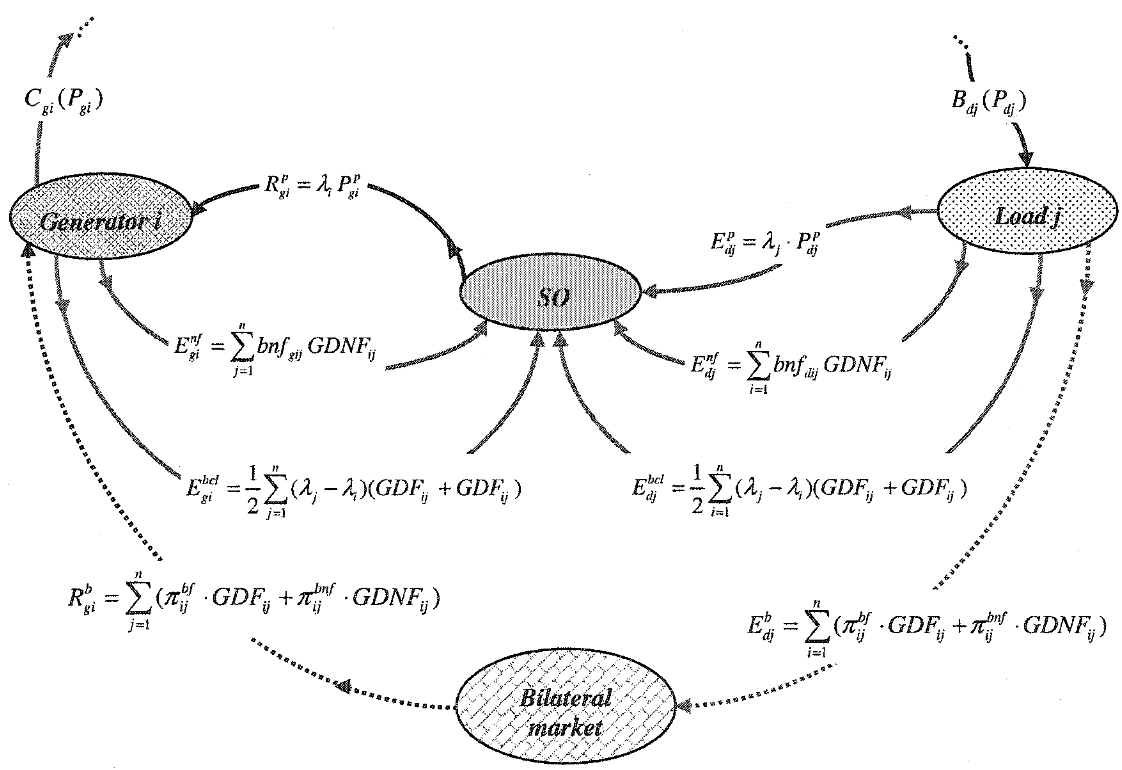

Figure 5-2. Financial transactions for operation with Free-of-Charge Curtailment Rights

5.5 Simulation Studies

The effect of curtailment offers and non-curtailment bids on the system operation is analyzed using the same network as in Chapter 4 (whose data are given in Appendix C). To facilitate the comparison between the original and the extended model, only Case C of Chapter 4, with the entire load supplied through bilateral trades, is examined here[20]. In this case, the pool does not supply any load as all the load is supplied by bilateral contracts. The pool does provide all transmission losses as well as some power re-dispatch in order to manage congestion.

As in Chapter 4, the following assumptions apply here:

- the bus voltage magnitudes of the transmission network are assumed fixed at one per unit by sufficient VAr sources;
- the total value of bus demands (combined pool and bilateral) are considered inelastic;
- the scheduled firm, GDF_{ij}, and non-firm, $GDNF_{ij}$, contracts are physical obligations, which means that generator i must inject the scheduled value into bus i while the consumers at bus j must absorb the same level of power;
- the bilateral contract rates charged by each generator are the same for all its contracts, and are equal to its marginal generation cost evaluated at its total approved firm and requested non-firm bilateral output, that is,

$$\pi_{ij}^{b} = \frac{d\Theta_i(P_{gi}^{b})}{dP_{gi}}; \quad \forall j. \tag{5.43}$$

where

$$P_{gi}^{b} = \sum_{j=1}^{n} (GDF_{ij}^{app} + GDNF_{ij}^{req}) \tag{5.44}$$

[20] In the rest of the text, when referring to "Case C", it will be understood that it is Case C from Chapter 4.

The results of Chapter 4, when the firm contracts were not subject to curtailment, revealed that this case led to heavy congested operation that became unprofitable for both generators and loads due to high power transmission payments and volatile nodal prices. The intention of this chapter is to demonstrate how the extra flexibility introduced by firm contract curtailment offers and non-firm contracts can be used to reduce congestion and hedge against such unprofitable conditions.

The simulations are performed for two cases:

- *case I* : only firm bilateral agreements with curtailment offers;
- *case II* : both firm and non-firm contracts, with respective curtailment offers and non-curtailment bids.

Both of these two cases are tested for two different values of curtailment offers:

- *i)* when all participants submit low curtailment offers, indicating a willingness to be curtailed if necessary to avoid high congestion payments;
- *ii)* when some contracts submit very high curtailment offers, indicating either strong satisfaction with their bilateral agreements or an attempt to earn extra revenue from curtailment (guessing that they have market power).

In addition Case I is examined for,

- *iii)* the effects of negative curtailment offers, which would be submitted when the trading partners wish to have their bilateral agreements completely curtailed, irrespective of the degree of congestion.

Moreover, for Cases I and II with both low and high curtailment offers, two ways of acquiring firm bilateral status are considered:

- *a)* Purchased Firm Bilateral Status with Financial Curtailment Rights;
- *b)* First-Come-First-Serve Firm Bilateral Status with Free-of-Charge Curtailment Rights.

For all of the above cases, the market clearing solution (generation levels, pool/bilateral mix, and power flows, as well as the nodal prices and the nodal price differences) depend on the values of curtailment offers, but not on the way in which firm bilateral status is acquired. On the other hand, the financial performance measures (generator and load revenues and expenditures) do depend on how firm status is acquired.

Thus, in next two subsections which examine Cases I and II, the analysis of the market clearing solutions is carried out first, followed by a calculation and analysis of the financial performance measures for each of the two possible firm status acquisition methods.

Figure 5-3 shows a block diagram of all the cases simulated and analyzed in this chapter.

5.5.1 Case I: Firm Bilateral Contracts with Curtailment Offers

Market Clearing Solution Characteristics

The vector of bus loads, $\mathbf{P}_d$, is here given by,

$$\mathbf{P}_d = [34 \quad 85 \quad 119 \quad 323 \quad 527]^T \quad \text{MW}. \tag{5.45}$$

Under the assumption of Case C, there is no pool demand so that $\mathbf{P_d} = [\mathbf{GDF}^{app}]^T \mathbf{e}$, where the approved firm bilateral contracts are here given as,

$$\mathbf{GDF}^{app} = \begin{bmatrix} 34 & 51 & 34 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{MW}. \tag{5.46}$$

To facilitate the comparison between case C and the various cases analyzed in this chapter, the results of the market clearing procedure for Case C are now repeated[21]. Table 5-4 shows the optimum dispatch while the financial performance measures appear in Table 5-8. Finally, the line flows are shown in Figure 5-4.

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[21] All tables numbered Table 5-4 - Table 5-26, as well as figures numbered Figure 5-4 - Figure 5-8 appear at the end of this chapter.

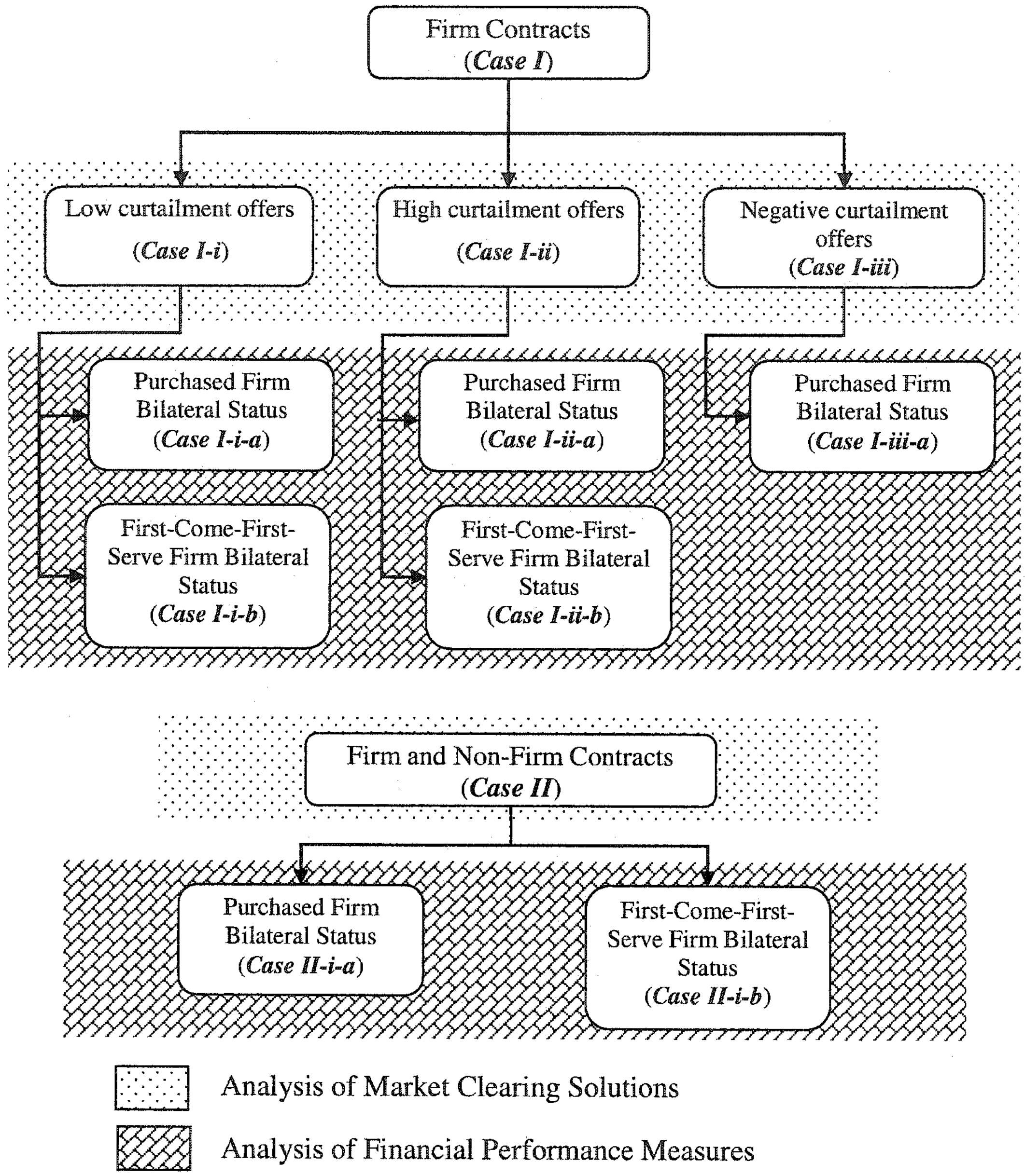

Figure 5-3. Diagram of tested cases

The solutions of the market clearing procedure are summarized in Table 5-1 for each of three cases, low, high and negative curtailment offers. In addition, Table 5-1 also summarizes case C for easy comparison. All of these cases are now described in greater detail.

(i) Low Curtailment Offers

This illustrates a situation where the bilateral traders are moderately satisfied with their agreements and show a willingness to be curtailed if necessary to avoid high power transfer payments. The curtailment offers are defined by,

$$\mathbf{bf} = \begin{bmatrix} 1.7 & 2.4 & 0.6 & 0.8 & 1 \\ - & 0.5 & 0.7 & 1.7 & 1.6 \\ - & - & 1.3 & 2 & 2.2 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix} \text{ \$/MWh.} \tag{5.47}$$

The unfilled positions in the matrix indicate that there are no corresponding bilateral contracts and thus no offers. In the optimization procedure, of course, these positions are filled with zeroes. However, it is also possible for an existing firm contract to submit a zero curtailment offer if the partners are completely indifferent to curtailment.

As defined by equation (5.2), bf_{ij}, the net curtailment offer of the bilateral contract GDF_{ij}, is the sum of the two terms, bf_{gij} and bf_{dij}, submitted by generator i and load j respectively. In the simulations carried out in this chapter it is assumed that these two terms are equal, so that $bf_{gij} = bf_{dij} = bf_{ij}/2$.

For the curtailment offers of (5.47) the results of the clearing procedure of (5.4) are given in Table 5-5. The corresponding scheduled values of the bilateral contracts are now,

Curtailed 100 %

Curtailed by 8.3 %

$$\mathbf{GDF} = \begin{bmatrix} 34 & 51 & 0 & 140.4 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW.} \tag{5.48}$$

It can be noticed from (5.48) that contract 1-3 is completely curtailed, while contract 1-4 is partially curtailed. The values of the line flows given in Figure 5-5 indicate that these contract curtailments have eliminated congestion, as line 1- 4 no longer operates at the limit. The absence of transmission congestion also leads to less volatile nodal price differences,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 0.3 & 1.8 & 2.9 & 6.0 \\ -0.3 & 0 & 1.5 & 2.6 & 5.7 \\ -1.8 & -1.5 & 0 & 1.0 & 4.2 \\ -2.9 & -2.6 & -1 & 0 & 3.5 \\ -6 & -5.7 & -4.2 & -3.5 & 0 \end{bmatrix} \text{\$/MWh} \tag{5.49}$$

This case is further discussed and compared to cases with high and negative curtailment offers later in this section.

(ii) High Curtailment Offers

High curtailment offers may occur if either the trading partners show strong satisfaction with their bilateral agreements or as an attempt to game and earn extra revenue from curtailment. This situation is simulated here by the curtailment offer matrix,

$$\mathbf{bf} = \begin{bmatrix} 170 & 240 & 60 & 80 & 79 \\ - & 25 & 70 & 140 & 160 \\ - & - & 1.3 & 2 & 2.2 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix} \text{\$/MWh.} \tag{5.50}$$

The market clearing results are given in Table 5-6. The matrix of scheduled contracts is now,

Curtailed by 18.3 %

$$\mathbf{GDF} = \begin{bmatrix} 34 & 51 & 27.7 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{MW.} \tag{5.51}$$

As (5.51) indicates, only the bilateral contract 1-3 has been curtailed by 18.3 % from the requested value defined by (5.46), an amount that is not sufficient to eliminate congestion. As Figure 5-6 indicates, line 1-4 is congested and this leads to high nodal price differences,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 43.6 & 59.2 & 72.8 & 72.7 \\ -43.6 & 0 & 15.6 & 29.2 & 29.1 \\ -59.2 & -15.6 & 0 & 13.6 & 13.5 \\ -72.8 & -29.2 & -13.6 & 0 & 0.1 \\ -72.7 & -29.1 & -13.5 & -0.1 & 0 \end{bmatrix} \text{ \$/MWh.} \qquad (5.52)$$

These nodal price differences result in poor financial performance measures as discussed in more detail later in this chapter.

(iii) Negative Curtailment Offers

An example is now given that illustrates how negative curtailment offers can be used by the trading partners to force the curtailment of some firm bilateral trades. This offer strategy may be used if the partners feel that they can get a better deal by trading at the pool prices. To simulate this case, the contract curtailment offer matrix, $\mathbf{bf}$, of equation (5.47) is modified by setting $bf_{35} = -0.5$ \$/MWh, so that ,

Negative curtailment offer

$$\mathbf{bf} = \begin{bmatrix} 1.7 & 2.4 & 0.6 & 0.8 & 1 \\ - & 0.5 & 0.7 & 1.7 & 1.6 \\ - & - & 1.3 & 2 & -0.5 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix} \text{ \$/MWh.} \qquad (5.53)$$

The matrix of scheduled firm contracts now becomes,

$$\mathrm{GDF} = \begin{bmatrix} 34 & 51 & \overset{\text{Curtailed by 100 \%}}{0} & \overset{\text{Curtailed by 8.3 \%}}{140.4} & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & \overset{\text{Curtailed by 100 \%}}{0} \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW.} \qquad (5.54)$$

This matrix shows that the negative curtailment offer of contract 3-5 does indeed result in a complete curtailment of this bilateral contract. In addition, the low curtailment offers of other bilateral parties allowed the SO to curtail contracts 1-3 and 1-4, thus eliminating congestion on line 1-4 as shown in Figure 5-7.

The results of the clearing procedure for this case are given in Table 5-7, with the values of nodal prices differences becoming,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 0.3 & 1.8 & 2.9 & 6.0 \\ -0.3 & 0 & 1.5 & 2.6 & 5.7 \\ -1.8 & -1.5 & 0 & 1.0 & 4.2 \\ -2.9 & -2.6 & -1 & 0 & 3.5 \\ -6 & -5.7 & -4.2 & -3.5 & 0 \end{bmatrix} \text{ \$/MWh.} \qquad (5.55)$$

Comparative Analysis of Market Clearing Solutions

To facilitate the comparison of Case C, Case I-i with low curtailment offers, Case I-ii with high curtailment offers, and Case I-iii with negative offers, the main characteristics of their market clearing solutions are summarized in Table 5-1. Each of these three cases is now discussed and compared with the other cases from the perspectives of:

- system operation;
- contract curtailments; and
- cost and nodal prices.

	Case C Firm bilateral trades with <u>no curtailment</u>	***Case I-i*** Firm bilateral trades with <u>low</u> curtailment offers	***Case I-ii*** Firm bilateral trades with <u>high</u> curtailment offers	***Case I-iii*** Firm bilateral trades with <u>negative</u> curtailment offers
1	No curtailment option	$\mathbf{bf}=\begin{bmatrix} 1.7 & 2.4 & 0.6 & 0.8 & 1 \\ - & 0.5 & 0.7 & 1.7 & 1.6 \\ - & - & 1.3 & 2 & 2.2 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix}$	$\mathbf{bf}=\begin{bmatrix} 170 & 240 & 60 & 80 & 79 \\ - & 25 & 70 & 140 & 160 \\ - & - & 1.3 & 2 & 2.2 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix}$	$\mathbf{bf}=\begin{bmatrix} 1.7 & 2.4 & 0.6 & 0.8 & 1 \\ - & 0.5 & 0.7 & 1.7 & 1.6 \\ - & - & 1.3 & 2 & -0.5 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix}$
2	Congestion on line 1-4	No congestion	Congestion on line 1-4	No congestion
3	Generator 2 at the lower bilateral limit	Generator 2 is free	Generator 2 at the lower bilateral limit	Generator 2 is free
4	Expensive generator 4 produces $P_{g4}=28\,\mathrm{MW}$	Expensive generator 4 produces $P_{g4}=0\,\mathrm{MW}$	Expensive generator 4 produces $P_{g4}=0\,\mathrm{MW}$	Expensive generator 4 produces $P_{g4}=0\,\mathrm{MW}$
5	$\mathbf{P}_g^b=[442\ \ 442\ \ 204\ \ 0\ \ 0]^T$ $\mathbf{P}_g^p=[0\ \ 0\ \ 20\ \ 28\ \ 0]^T$	$\mathbf{P}_g^b=[395.4\ \ 442\ \ 204\ \ 0\ \ 0]^T$ $\mathbf{P}_g^p=[0\ \ 35.9\ \ 59.6\ \ 0\ \ 0]^T$	$\mathbf{P}_g^b=[435.6\ \ 442\ \ 204\ \ 0\ \ 0]^T$ $\mathbf{P}_g^p=[0\ \ 0\ \ 55.2\ \ 0\ \ 0]^T$	$\mathbf{P}_g^p=[395.4\ \ 442\ \ 102\ \ 0\ \ 0]^T$ $\mathbf{P}_g^p=[0\ \ 35.3\ \ 161.6\ \ 0\ \ 0]^T$
6	$\mathbf{P}_d^b=[34\ \ 85\ \ 119\ \ 323\ \ 527]^T$ $\mathbf{P}_d^p=[0\ \ 0\ \ 0\ \ 0\ \ 0]^T$	$\mathbf{P}_d^b=[34\ \ 85\ \ 85\ \ 310.4\ \ 527]^T$ $\mathbf{P}_d^p=[0\ \ 0\ \ 34\ \ 12.6\ \ 0]^T$	$\mathbf{P}_d^b=[34\ \ 85\ \ 112.8\ \ 323\ \ 527]^T$ $\mathbf{P}_d^p=[0\ \ 0\ \ 6.2\ \ 0\ \ 0]^T$	$\mathbf{P}_d^b=[34\ \ 85\ \ 85\ \ 310.4\ \ 425]^T$ $\mathbf{P}_d^p=[0\ \ 0\ \ 34\ \ 12.6\ \ 102]^T$
7	$\mathbf{GD}^{app}=\begin{bmatrix} 34 & 51 & 34 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix}$	$\mathbf{GDF}=\begin{bmatrix} 34 & 51 & 0 & 140.4 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix}$	$\mathbf{GDF}=\begin{bmatrix} 34 & 51 & 27.7 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix}$	$\mathbf{GDF}=\begin{bmatrix} 34 & 51 & 0 & 140.4 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix}$
8	$\boldsymbol{\lambda}=[-65.3\ \ 9.1\ \ 35.1\ \ 57.1\ \ 54.6]^T$	$\boldsymbol{\lambda}=[35\ \ 35.3\ \ 36.9\ \ 37.9\ \ 41]^T$	$\boldsymbol{\lambda}=[-22.6\ \ 21\ \ 36.7\ \ 50.2\ \ 50.1]^T$	$\boldsymbol{\lambda}=[35\ \ 35.3\ \ 36.9\ \ 37.9\ \ 41]^T$
9	$\{\lambda_j-\lambda_i\}=\begin{bmatrix} 0 & 74.4 & 100.4 & 122.4 & 120 \\ -74.4 & 0 & 26 & 48 & 45.5 \\ -100.4 & -26 & 0 & 22 & 19.5 \\ -122.4 & -42 & -16 & 0 & 3.5 \\ -120 & -46.5 & -19.5 & -3.5 & 0 \end{bmatrix}$	$\{\lambda_j-\lambda_i\}=\begin{bmatrix} 0 & 0.3 & 1.8 & 2.9 & 6.0 \\ -0.3 & 0 & 1.5 & 2.6 & 5.7 \\ -1.8 & -1.5 & 0 & 1.0 & 4.2 \\ -2.9 & -2.6 & -1 & 0 & 3.5 \\ -6 & -5.7 & -4.2 & -3.5 & 0 \end{bmatrix}$	$\{\lambda_j-\lambda_i\}=\begin{bmatrix} 0 & 43.6 & 59.2 & 72.8 & 72.7 \\ -43.6 & 0 & 15.6 & 29.2 & 29.1 \\ -59.2 & -15.6 & 0 & 13.6 & 13.5 \\ -72.8 & -29.2 & -13.6 & 0 & 0.1 \\ -72.7 & -29.1 & -13.5 & -0.1 & 0 \end{bmatrix}$	$\{\lambda_j-\lambda_i\}=\begin{bmatrix} 0 & 0.3 & 1.8 & 2.9 & 6.0 \\ -0.3 & 0 & 1.5 & 2.6 & 5.7 \\ -1.8 & -1.5 & 0 & 1.0 & 4.2 \\ -2.9 & -2.6 & -1 & 0 & 3.5 \\ -6 & -5.7 & -4.2 & -3.5 & 0 \end{bmatrix}$

Table 5-1. Summary of technical characteristics for all Case I examples

System Operation

In Case C, solved for the original pool/bilateral model without curtailment options, high levels of bilateral trades caused congestion on line 1-4, and also forced generators 1 and 2 to operate at their lower bilateral limits. Moreover, due to congestion re-dispatch, the expensive generator 4 was also scheduled to produce 28 MW.

When the bilateral parties of firm contracts submit low curtailment offers as in Case I-i, the SO is able to curtail some of the approved firm bilateral contracts by an amount sufficient to eliminate congestion. In comparison with Case C, generator 1 is still operating at its lower bilateral limit, however generator 2 is now free and none of the lines are congested. This is a less constrained case which therefore gives a more efficient operation.

However, the high curtailment offers submitted in Case I-ii preclude the SO from sufficiently modifying the approved firm contracts to eliminate congestion. As Table 5-1 indicates, the system operation in Case I-ii is closer to Case C than to Case I-i, as line 1-4 remains congested and both generators 1 and 2 operate at their lower bilateral limits. However, since the expensive generator 4 produces zero output, the operation now is a bit cheaper than in Case C, although more expensive than in Case I-i.

In Case I-iii with negative curtailment offers, there are no differences in what concerns generation and line limits in comparison with Case I-i as the two curtailment offer matrices are very similar except for element 3-5 which in Case I-iii is negative.

The above results show that low values of curtailment offers can have a significant impact on system operation by reducing or eliminating transmission congestion as well as out of merit operation (generators that operate at their lower bilateral bound). On the other hand, high values of curtailment offers may be counter-productive since they do not provide the SO with the curtailment flexibility to alleviate or eliminate congestion.

Contract curtailments

Rows 5, 6 and 7 of Table 5-1 show that although the approved contracts called for the entire demand to be supplied through bilateral contracts (as in Case C), in cases I-i, I-ii, and I-iii, some contract curtailment is scheduled by the market clearing procedure, replacing the curtailed amounts with pool-supplied components. The level of curtailment however depends strongly on the curtailment offers submitted by bilateral parties.

In Case I-i for example, the firm bilateral contract 1-3 is 100% curtailed while contract 1-4 is reduced by 8.3% from their approved values. The firm contracts of the other generators however are entirely honored.

On the other hand, because of the high curtailment offers in Case I-ii, with the exception of GDF_{13} none of the firm contracts are curtailed. Thus, whereas in Case I-i, contract 1-4 had been reduced by 8.3%, it is now fully honored, while contract 1-3 that had been totally cancelled in Case I-i, is now reduced by only 18.3 %.

As Cases I-iii and I-i have nearly the same curtailment offer matrices, the same contract curtailment occurs, with the exception of contract 3-5 that is now completely curtailed because of its negative curtailment offer.

What is common for all of these cases is that for positive offers there is a tendency to curtail only the contracts of generator 1. This is not a surprising result considering that in Case C the nodal price at bus 1 was negative (see row 8) which was an economic signal to decrease the net power injection into that bus by either increasing demand or by decreasing generation.

The results also demonstrate that the level of contract curtailment depends on the values of curtailment offers. For instance, modifications of the scheduled contracts in Case-I are consistent with the curtailment offers in (5.47) (see also row 1), as higher offers result in higher scheduled values (or equivalently in smaller modifications from the approved values). Thus, of the bilateral contracts originating at generator 1, bilateral contract GDF_{13} with the lowest curtailment offer ($bf_{13} = 0.6$ \$/MWh) has been completely curtailed. As for the other generator 1 contracts, only the agreement GDF_{14} was partly curtailed, as this contract has the second lowest curtailment offer, $bf_{14} = 0.8$ \$/MWh. Furthermore, note that even though the contracts of generator 2, GDF_{22} and GDF_{23} submitted lower curtailment offers than contract GDF_{14} of generator 1 ($bf_{22} = 0.5$ and $bf_{23} = 0.7$ \$/MWh, respectively), they were not curtailed because such measures would not remove congestion. This result shows that even for relatively low curtailment offers, the tendency is to fully honor the approved transactions unless they cause congestion.

On the other hand, for Case I-ii with high curtailment offers only one contract, GDF_{13}, with the lowest curtailment offer was reduced. This curtailment is attributed to the strong influence that the output of generator 1 has on transmission congestion.

In Case I-iii, the negative curtailment offer of contract GDF_{35} resulted in its complete curtailment, thus demonstrating that negative offers lead to contract curtailment even when there is no advantage in eliminating or relieving congestion.

For all the above cases, the transmission losses and congestion re-dispatch are supplied by the pool. In addition, the amount of power curtailed from the firm bilateral contracts is replaced by equivalent pool components, thereby defining a new pool/bilateral mix. Thus, for the lower curtailment offers of Case I-i, the proportion of pool generation increases with respect to its bilateral counterpart, when compared to Case I-ii. Moreover, as generator 2 is free in Cases I-i and I-iii, its pool generation component has increased from 0 MW (in Case C) to 35.3 MW. In addition, in Case I-iii, the generation and load pool components are even higher because of the total curtailment of bilateral contract GDF_{35} whose 102 MW now become part of the pool trades.

Cost and nodal prices

As Table 5-4,Table 5-5, Table 5-6 and Table 5-7 show, although the total generation cost[22] in Case I-ii with high curtailment offers (35,017 $/h) has decreased from that of Case C (35,606 $/h), it is still higher that the total costs in Cases I-i and I-iii (34,928 $/h) with no congestion.

The values of nodal price differences in row 9 of Table 5-1 reveal to what extent the selective curtailments of the market clearing process were successful in lowering the nodal price differences and in securing trades with low power transfer payments. In Cases I-i and I-iii, the low curtailment offers result in operation without transmission congestion

[22] Recall that this generation cost is calculated based on submitted generator offers, $\Theta_{gi}(P_{gi})$. As the true cost $C_{gi}(P_{gi})$ is private information known only to the generator, all analyses are carried out under the assumption that $C_{gi}(P_{gi}) = \Theta_{gi}(P_{gi})$

for which the nodal price differences are significantly lower than for the heavily congested Case C. As for Case I-ii, whereas the operation remains congested, even the slight curtailment of contract GDF_{13} reduces the values of nodal price differences by as much as 40%.

These results show that it is in the interest of the bilateral trading parties to submit low curtailment offers in order to provide the SO with the necessarily flexibility to curtail the bilateral contracts and thereby reduce nodal price differences. As the analyses of financial performance measures of the next section show, the bilateral parties are unlikely to benefit from bilateral contracts that cause high nodal price differences because they are then faced with high power transfer payments.

Financial Performance Measures

As financial performance measures depend on the way in which the firm bilateral status is acquired, the cases discussed above are now analyzed under the following two conditions:

- Purchased Firm Bilateral Status
  - Case I-i-a with low curtailment offers (detailed in Table 5-10 andTable 5-11);
  - Case I-ii-a with high curtailment offers (detailed in Table 5-12 and Table 5-13);
  - Case I-iii-a with negative curtailment offers (detailed in Table 5-14 and Table 5-15).
- First-Come-First-Serve Firm Bilateral Status
  - Case I-i-b with low curtailment offers (detailed in Table 5-16 and Table 5-17);
  - Case I-ii-b with high curtailment offers (detailed in Table 5-18 and Table 5-19).

Recall that the Purchased Firm Bilateral Status is acquired by the bilateral parties by buying it from the SO. In return, they are awarded not only a firm right and obligation to transfer the agreed to power, but they also obtain a Financial Curtailment Right that entitles them to collect a curtailment revenue if the contract is curtailed. On the other hand, as the First-Come-First-Serve firm status is obtained for free, under this scheme the bilateral partners are not entitled to curtailment revenue even though they still submit curtailment offers. Such offers now merely reflect the partners' willingness to be curtailed for economic reasons, but they do not entitle the partners to any curtailment revenue.

To facilitate the comparison of the various cases simulated, a sub-set of financial performance measures are summarized in Table 5-2, the details of which are found in Table 5-8 -Table 5-15.

Thus, row 1 of Table 5-2 shows the individual generator payments used to purchase firm bilateral status, Ef_{gi}^{app}, while the corresponding payments by the loads, Ef_{dj}^{app}, are given in row 8. It is assumed that the rate offered by the bilateral parties for the firm status, bf_{ij}^{app}, is equally split between a generator and a load, and that its value is 10% of the bilateral price defined by equation (4.23). For the local bilateral contracts that are agreed on between a generator and a load at the same bus, the value of bf_{ij}^{app} is zero.

The generator revenues (in \$/h) and the corresponding rates of revenue (in \$/MWh), are given in rows 2-7 of Table 5-2 as follows:

- the net generator revenues, R_{gi}, are given in row 2, while the corresponding rates of revenue, R_{gi} / P_{gi}, are in row 3.
- the net revenue associated with bilateral trades, $\tilde{R}_{gi}^{b}$, is shown in row 4. This includes all revenues and payments associated with bilateral trading, that is,

$$\tilde{R}_{gi}^{b} = R_{gi}^{b} - Ef_{gi}^{bcl} + R_{gi}^{f} \,. \tag{5.56}$$

- The associated rates of revenue, $\tilde{R}_{gi}^{b} / P_{gi}^{b}$, are in row 5. The term R_{gi}^{b} and in (5.56) is defined by equations (5.6), while Ef_{gi}^{bcl} and R_{gi}^{f}, depends on the way the firm bilateral status is obtained and are defined by (5.10) or (5.19) and (5.11) or (5.20).

- the net revenues associated with sales to the pool, R_{gi}^{p}, defined by , is given in row 6, while row 7 shows the corresponding rates of revenue, R_{gi}^{p} / P_{gi}^{p}. Note that if $P_{gi}^{p} > 0$ these rates are equal to the nodal prices, λ_i.

Similarly, the net load expenditures (in \$/h) and the corresponding rates of expenditure (in \$/MWh) are given in rows 9-14, in the subsequent order:

- the net load expenditures, E_{dj}, are given in row 9, with the associated rates of expenditure, E_{dj} / P_{dj}, being defined in row 10.
- the net bilateral load expenditures, $\tilde{E}_{dj}^{b}$, defined by,

$$\tilde{E}_{dj}^{b} = E_{dj}^{b} + Ef_{dj}^{bcl} - R_{dj}^{f}. \tag{5.57}$$

  are given in row 11, with the associated rates of expenditure, $\tilde{E}_{dj} / P_{dj}^{b}$, in row 12. The variable E_{dj}^{b}, in equation is defined by (5.27), while Ef_{dj}^{bcl} and R_{dj}^{f} depend on the way in which firm bilateral status is obtained and are defined by (5.28) or (5.35) and (5.29) or (5.36).
- the net pool load expenditures, E_{dj}^{p}, are shown in row 13, with the associated rates, E_{dj}^{p} / P_{dj}^{p}, given in row 14;

In addition, the merchandising surplus is given in row 15.

The cases defined in Table 5-2 are now discussed and mutually compared from the perspectives of:

- generator revenue components and corresponding rates;
- load expenditure components and corresponding rates;
- merchandising surplus;
- net prices of bilateral trades.

For each of these perspectives, comparisons are carried out first among Cases I-i-a, I-ii-a and I-iii-a with Purchased Firm Bilateral Status. This is followed by an evaluation of how Purchased vs. First-Come-First-Serve firm status affects the financial performance measures of individual generators and loads.

	Case C Firm bilateral trades with no curtailment	*Case I-i* Firm bilateral trades with low curtailment offers		*Case I-ii* Firm bilateral trades with high curtailment offers		*Case I-iii* Firm bilateral trades with negative curtailment offers
	First-Come-First-Serve firm bilateral status	***Case I-i-a*** Purchased firm bilateral status	***Case I-i-b*** First-Come-First-Serve firm bilateral status	***Case I-ii-a*** Purchased firm bilateral status	***Case I-i-b*** First-Come-First-Serve firm bilateral status	***Case I-iii*** Purchased firm bilateral status
1	$\mathbf{Ef}^{app} = \mathbf{0}$	$\mathbf{Ef}_g^{app} = \begin{bmatrix} 768.7 \\ 699 \\ 261.5 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{Ef}^{app} = \mathbf{0}$	$\mathbf{Ef}_g^{app} = \begin{bmatrix} 768.7 \\ 699 \\ 261.5 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{Ef}^{app} = \mathbf{0}$	$\mathbf{Ef}_g^{app} = \begin{bmatrix} 768.7 \\ 699 \\ 261.5 \\ 0 \\ 0 \end{bmatrix}$
2	$\mathbf{R}_g = \begin{bmatrix} -6,514 \\ 6,045 \\ 6,131 \\ 1,620 \\ 0 \end{bmatrix}$	$\mathbf{R}_g = \begin{bmatrix} 13,422 \\ 14,782 \\ 8,669 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g = \begin{bmatrix} 14,176 \\ 15,481 \\ 8,931 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g = \begin{bmatrix} 2,154 \\ 8,729 \\ 7,701 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g = \begin{bmatrix} 2,736 \\ 9,428 \\ 7,963 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g = \begin{bmatrix} 13,422 \\ 14,782 \\ 9,131 \\ 0 \\ 0 \end{bmatrix}$
3	$\mathbf{R}_g./\mathbf{P}_g = \begin{bmatrix} -14.7 \\ 13.7 \\ 27.7 \\ 57.6 \\ 0 \end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g = \begin{bmatrix} 33.9 \\ 31 \\ 32.9 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g = \begin{bmatrix} 35.8 \\ 32.4 \\ 33.9 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g = \begin{bmatrix} 5 \\ 19.7 \\ 29.7 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g = \begin{bmatrix} 6.3 \\ 21.3 \\ 30.7 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g = \begin{bmatrix} 33.9 \\ 31 \\ 34.6 \\ 0 \\ 0 \end{bmatrix}$

Table 5-2. Summary of financial performance characteristics for all Case I examples

	Case C	*Case I-i-a*	*Case-I-i-b*	*Case I-ii-a*	*Case I-ii-b*	*Case I-iii*
4	$\tilde{\mathbf{R}}_g^b = \begin{bmatrix} -6,513 \\ 6,045 \\ 5,415 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b = \begin{bmatrix} 13,422 \\ 13,535 \\ 6,472 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b = \begin{bmatrix} 14,176 \\ 14,234 \\ 6,733 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b = \begin{bmatrix} 2,154 \\ 8,729 \\ 5,678 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b = \begin{bmatrix} 2,736 \\ 9,428 \\ 5,939 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b = \begin{bmatrix} 13,422 \\ 13,535 \\ 3,174 \\ 0 \\ 0 \end{bmatrix}$
5	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p = \begin{bmatrix} -14.7 \\ 13.7 \\ 26.5 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^b = \begin{bmatrix} 33.9 \\ 30.6 \\ 31.7 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p = \begin{bmatrix} 35.8 \\ 32.3 \\ 33 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p = \begin{bmatrix} 5 \\ 19.7 \\ 27.8 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p = \begin{bmatrix} 6.3 \\ 21.3 \\ 29.1 \\ 0 \\ 0 \end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p = \begin{bmatrix} 33.9 \\ 30.6 \\ 31.1 \\ 0 \\ 0 \end{bmatrix}$
6	$\mathbf{R}_g^p = \begin{bmatrix} 0 \\ 0 \\ 716 \\ 1,620 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p = \begin{bmatrix} 0 \\ 1,247 \\ 2,198 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p = \begin{bmatrix} 0 \\ 1,247 \\ 2,198 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p = \begin{bmatrix} 0 \\ 0 \\ 2,024 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p = \begin{bmatrix} 0 \\ 0 \\ 2,024 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p = \begin{bmatrix} 0 \\ 1,247 \\ 5,958 \\ 0 \\ 0 \end{bmatrix}$
7	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 0 \\ 35.1 \\ 57.1 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 35.3 \\ 36.9 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 35.3 \\ 36.9 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 0 \\ 36.7 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 0 \\ 36.7 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 35.3 \\ 36.9 \\ 0 \\ 0 \end{bmatrix}$

Table 5-2. Summary of financial performance characteristics for all Case I examples (cont.)

	Case C	*Case I-i-a*	*Case-I-i-b*	*Case I-ii-a*	*Case I-ii-b*	*Case I-iii*
8	$\mathbf{Ef}^{app}=\mathbf{0}$	$\mathbf{Ef}_d^{app}=\begin{bmatrix}0\\96.1\\122.3\\579.3\\931.4\end{bmatrix}$	$\mathbf{Ef}^{app}=\mathbf{0}$	$\mathbf{Ef}_d^{app}=\begin{bmatrix}0\\96.1\\122.3\\579.3\\931.4\end{bmatrix}$	$\mathbf{Ef}^{app}=\mathbf{0}$	$\mathbf{Ef}_d^{app}=\begin{bmatrix}0\\96.1\\122.3\\579.3\\931.4\end{bmatrix}$
9	$\mathbf{E}_d=\begin{bmatrix}1{,}128\\4{,}985\\6{,}338\\24{,}371\\35{,}619\end{bmatrix}$	$\mathbf{E}_g=\begin{bmatrix}1{,}281\\3{,}190\\4{,}300\\12{,}541\\21{,}017\end{bmatrix}$	$\mathbf{E}_d=\begin{bmatrix}1{,}281\\3{,}094\\4{,}188\\11{,}967\\20{,}056\end{bmatrix}$	$\mathbf{E}_d=\begin{bmatrix}1{,}281\\4{,}294\\5{,}207\\19{,}816\\30{,}140\end{bmatrix}$	$\mathbf{E}_d=\begin{bmatrix}1{,}281\\4{,}198\\5{,}271\\19{,}237\\29{,}209\end{bmatrix}$	$\mathbf{E}_d=\begin{bmatrix}1{,}281\\3{,}190\\4{,}300\\12{,}541\\21{,}530\end{bmatrix}$
10	$\mathbf{E}_d./\mathbf{P}_d=\begin{bmatrix}37.7\\58.6\\53.3\\75.4\\67.6\end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d=\begin{bmatrix}37.7\\37.5\\36.1\\38.8\\39.9\end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d=\begin{bmatrix}37.7\\36.4\\35.2\\37\\38.1\end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d=\begin{bmatrix}37.5\\50.5\\43.7\\61.3\\57.2\end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d=\begin{bmatrix}37.7\\49.4\\44.3\\59.6\\55.4\end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d=\begin{bmatrix}37.7\\37.5\\36.1\\38.8\\40.8\end{bmatrix}$
11	$\tilde{\mathbf{E}}_d^b=\begin{bmatrix}1{,}281\\4{,}985\\6{,}338\\24{,}371\\35{,}619\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b=\begin{bmatrix}1{,}281\\3{,}190\\3{,}046\\12{,}062\\21{,}017\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b=\begin{bmatrix}1{,}281\\3{,}094\\2{,}934\\11{,}488\\20{,}086\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b=\begin{bmatrix}1{,}281\\4{,}294\\4{,}978\\19{,}816\\30{,}140\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b=\begin{bmatrix}1{,}281\\4{,}198\\5{,}042\\19{,}237\\29{,}209\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b=\begin{bmatrix}1{,}281\\3{,}190\\3{,}046\\12{,}062\\17{,}343\end{bmatrix}$

Table 5-2. Summary of financial performance characteristics for all Case I examples (cont.)

	Case C	*Case I-i-a*	*Case-I-i-b*	*Case I-ii-a*	*Case I-ii-b*	*Case I-iii*
12	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b=\begin{bmatrix}37.7\\58.6\\53.3\\75.4\\67.6\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b=\begin{bmatrix}37.7\\37.5\\35.8\\38.9\\39.9\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b=\begin{bmatrix}37.7\\36.4\\34.5\\37\\38.1\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b=\begin{bmatrix}37.7\\50.5\\44.1\\61.3\\57.2\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b=\begin{bmatrix}37.7\\49.4\\44.7\\59.6\\55.4\end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b=\begin{bmatrix}37.7\\37.5\\35.8\\38.9\\40.8\end{bmatrix}$
13	$\mathbf{E}_d^p=\begin{bmatrix}0\\0\\0\\0\\0\end{bmatrix}$	$\mathbf{E}_d^p=\begin{bmatrix}0\\0\\1,253\\479\\0\end{bmatrix}$	$\mathbf{E}_d^p=\begin{bmatrix}0\\0\\1,253\\479\\0\end{bmatrix}$	$\mathbf{E}_d^p=\begin{bmatrix}0\\0\\228\\0\\0\end{bmatrix}$	$\mathbf{E}_d^p=\begin{bmatrix}0\\0\\228\\0\\0\end{bmatrix}$	$\mathbf{E}_d^p=\begin{bmatrix}0\\0\\1,253\\479\\4,187\end{bmatrix}$
14	$\mathbf{E}_d^p./\mathbf{P}_d^p=\begin{bmatrix}0\\0\\0\\0\\0\end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p=\begin{bmatrix}0\\0\\36.9\\37.9\\0\end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p=\begin{bmatrix}0\\0\\36.9\\37.9\\0\end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p=\begin{bmatrix}0\\0\\36.7\\0\\0\end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p=\begin{bmatrix}0\\0\\36.7\\0\\0\end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p=\begin{bmatrix}0\\0\\36.9\\37.9\\41\end{bmatrix}$
15	$MS=65,312$	$MS=5,454$	$MS=2,028$	$MS=42,155$	$MS=39,070$	$MS=5,507$

Table 5-2. Summary of financial performance characteristics for all Case I examples (cont.)

Generator Revenue Components and Corresponding Rates

A striking difference between the various generator revenues and associated rates for Case C and Case I-i-a with low curtailment offers can be seen in rows 2-7 of Table 5-2. In addition, the reader may wish to compare the results from Table 5-10 and Table 5-6 . As row 2 of Table 5-2 indicates, all participants except generators 4 and 5 are individually better off in Case I-i-a compared to Case C because of the contract curtailment. For instance, the revenue of generator 1 has increased from a negative value of $R_{g1} = -6,514$ \$/h in Case C to $R_{g1} = 13,422$ \$/h in Case I-i-a. As for generator 4, it is worse off with curtailment since it produces no power, and its revenue drops from 1,260 \$/h to 0. A similar trend can be seen for the pool and bilateral components in rows 4 and 6.

Similarly, the rates of revenue associated with each type of trading (rows, 3, 5 and 7), are significantly higher for generators 1, 2 and 3. For instance, the rate of return for the net revenue of generator 1, R_{g1} / P_{g1}, has increased from -14.7 for Case C to 33.9 \$/MWh in Case I-i-a. Likewise, for generator 2 the rate of revenue R_{g2} / P_{g2} have increased from 13.7 to 31 \$/MWh, while for the rate associated with the net revenue of bilateral trades, $\tilde{R}^b_{g2} / P^b_{g2}$, it rose from 13.7 to 30.6 \$/MWh. As for the rate of pool revenue, in Case C generator 2 operated at its lower bilateral limit and thus did not sell any power to the pool. In Cases I-i-a and I-iii-a however generator 2 is free and sells 35.3 MW for the rate $R^p_{g2} / P^p_{g2} = 36.7$ \$/MWh, which is also the nodal price at bus 2.

Analysis of similar financial measures for Case I-ii-a with high curtailment offers reveals that insufficient contract curtailment results in lower generator revenues. As, rows 2, 4 and 6 indicate, in comparison with Case I-i-a, the revenues of generators 1, 2 and 3 have dropped, although they are still above the levels seen in Case C. Again, the most significant change is for generator 1 whose revenue is now 2,154 \$/h, compared to 13,422 \$/h in Case I-i-a and -6,514 \$/h in Case C. A similar effect can be observed for the rates of revenue given in rows 3, 5 and 7, which show that, in comparison with Case I-i-a, the worst situation is with generator 1 whose rate of revenue, R_{g1} / P_{g1}, has dropped from 33.9 to 5 \$/MWh.

As the more detailed results of Table 5-12 for Case I-ii-a indicate, the poor financial results are due to transmission congestion and high power transfer payments. Furthermore, most of the bilateral parties that submit high curtailment offers prevent any curtailment and thus are not able to collect any curtailment revenue, R_{ij}^{f}.

The high curtailment offers submitted by generator 1 result in insufficient curtailment of its contracts. Thus, this generator continues to be the main cause of congestion and its financial performance is highly affected by this inefficient operation. While this generator receives a relatively high curtailment payment of 186.7 \$/h for the curtailment of its contract GDF_{13}, that revenue is wiped out by an increase in power transfer payments, that for this generator are now 13,684 \$/h.

The financial performance measures of Case I-iii-a with negative curtailment offers are given in Table 5-14, as well as in rows 2-7 of Table 5-2. These results are very close to those of Case I-i-a, the only difference being in the curtailment of contract GDF_{35} (with negative offer), which proves to be beneficial to generator 3. Even though this generator paid to have one of its contracts curtailed, its total revenue slightly increased to 9,131 \$/h in Case I-iii-a from 8,669 \$/h in Case I-i-a.

Load Expenditure Components and Corresponding Rates

Similarly to the generators, it can be noted from rows 9, 11 and 13 that the load payments in Case I-i-a with low curtailment offers have decreased under curtailment, and the rates associated with each type of trading (rows 12, 14) as well as the overall expenses (row 10) are lower in comparison with Case C. The only exception are the expenditures and rates of expenditure for load 1, which has only local bilateral purchases from generator 1 that remain constant for all cases as such expenditures are unaffected by transmission congestion.

Thus, the bilateral contract curtailments scheduled in Case I-i-a prove to be equally beneficial to the loads as they are for the generators. This indicates that both parties have similar interest when submitting curtailment offers.

In Case I-ii-a with high curtailment offers, with the exception of load 1 all other loads are now worse off. This can be seen in the total load payments, E_{dj}, as shown in row 9, and in the associated rates of expenditure E_{dj} / P_{dj}, as seen in row 10. The same conclusion applies for the net expenditures associated with both bilateral and pool trades given in rows 11 and 13, as well as for the corresponding rates defined in rows 12 and 14. The reason is that loads have to pay high power transfer payments which are indicated in Table 5-12, and this makes their payments closer to those of Case C than to those of Case I-i-a. The only exception is load 1 which, as pointed out before, is unaffected by the contract curtailments since it only has one bilateral contract with the local generator.

Thus, although loads 2 to 5 buy bilaterally from all three generators, the high levels of bilateral output of generator 1 cause expensive operation for all. Since these loads do not show sufficient flexibility to curtail their bilateral trades with generator 1, they are faced with high power transfer payments. For example, because of its high curtailment offer, contract 1-3 is curtailed only by 8.3%, compared to 100% in Case I-i-a, which now forces load 3 to pay power transfer payment of 1,211 $/h (Table 5-12). This amount is much higher than the 148.5 $/h that load 3 paid in Case I-i-a (Table 5-10). Even the curtailment revenue that brings 186.7 $/h to load 3 is insufficient to cover the difference between the power transfer payments of these two cases.

In comparison to Case I-i-a, the only difference in Case I-iii-a is observed for load 5 which has curtailed its contract GDF_{35}. This load is now worse off, as its total expenditure has increased from 4,188 to 4,300 $/h. The revenues of all other loads remain unchanged.

Merchandising Surplus

In Case I-i-a with low curtailment offers, the overall total revenues and expenses are respectively, $\sum_{i=1}^{n} R_{gi} = 36,873$ and $\sum_{j=1}^{n} E_{dj} = 42,329$ in $/h. In comparison the results of Case C are $\sum_{i=1}^{n} R_{gi} = 7,282$ and $\sum_{j=1}^{n} E_{dj} = 72,594$. Thus the merchandising surplus, MS, has significantly decreased to 5,454 $/h, as opposed to 65,312 $/h for Case C. These results become even more interesting in light of the very small value of the overall curtailment costs, as the SO pays only 15.3 $/h to the bilateral parties for the total bilateral contract curtailment.

For Case I-ii-a with high curtailment offers, the total generator revenues and load expenses worsen with respect to the low curtailment offer Case I-i-a, as these have changed from $\sum_{i=1}^{n} R_{gi} = 36,873$ and $\sum_{j=1}^{n} E_{dj} = 42,329$ (in \$/h) in Case I-i-a to $\sum_{i=1}^{n} R_{gi} = 18,684$ and $\sum_{i=j}^{n} E_{dj} = 60,973$ for the case with high offers. The resulting high merchandising surplus of 42,155 \$/h in Case I-ii-a is therefore significantly higher than 5,454 \$/h for Case I-i-a, and is closer to the value of 65,312 \$/h for Case C. A high MS is a signal that additional transmission capacity is economically desirable in order to implement the approved trades. This economic signal also indicates that for the same transmission capacity, the bilateral contracts should be modified to improve the overall economic operation.

In Case I-iii-a that illustrates what happens under negative curtailment offers, the values of the total generator revenues, $\sum_{i=1}^{n} R_{gi} = 37,335$, and the total load expenses, $\sum_{j=1}^{n} E_{dj} = 42,842$ \$/h, are slightly above the values in Case I-i-a, but are far better than the values seen in Cases C and I-ii-a which operated under congestion. The merchandising surplus is now 5,507 \$/h, a value slightly above the 5,454 \$/h in Case I-i-a, but much lower than in Cases C and I-ii-a. This is an expected result as there is no congestion in Case I-iii-a, and the replacement of bilateral contract GDF_{35} with pool supply was beneficial to generator 1 although more expensive for load 5.

<u>Net Prices of Bilateral Trades</u>

The net contract prices are given for Cases C, I-i-a, I-ii-a and I-iii-a from the perspective of both generators, $\hat{\pi}_{gij}^{bf}$, and loads, $\hat{\pi}_{dij}^{bf}$, in Table 5-9,Table 5-11 ,Table 5-13, andTable 5-15 respectively, and they can be compared with the nodal prices that for each of theses cases are given in Table 5-4, Table 5-5, Table 5-6 and Table 5-7. This comparison indicates how well the trading strategies and partners have been chosen, and which contracts should be reevaluated in the future.

Purchased vs. First-Come-First-Serve Bilateral Status

The results of Case I-i-b for low curtailment offers under First-Come-First-Serve Firm Bilateral Status are given in Table 5-16, while the results for the Case I-ii-b with high curtailment offers are shown in Table 5-18. For both of these two cases with First-Come-First-Serve Firm Bilateral Status, the total generator revenues and load expenditures differ from the cases with Purchased Firm Bilateral Status in two ways: (i) the values of curtailment revenues collected by the generators and loads; and (ii) the amount paid by the bilateral parties to obtain firm bilateral status.

The results of these cases reveal that any earnings from curtailment when bilateral parties submit high curtailment offers may not be sufficient to outweigh an increase in power transfer payments caused by congestion. For example, in Case I-i-a with low curtailment offers, the total curtailment revenue paid by the SO is 15.3 \$/h, while in Case I-ii-a with high curtailment offers is jumped to 186.7 \$/h. The additional incomes that bilateral parties collect under Purchased Firm Bilateral Status are small in comparison with the corresponding increase in power transfer payments which in the cases with high curtailment bids totals 20,433 \$/h compared to 1,870 \$/h for the cases with low curtailment offers.

5.5.2 Case II: Firm and Non-Firm Bilateral Contracts with Curtailment Offers and Non-Curtailment Bids

The subsequent examples illustrate a combined pool/bilateral model when both firm and non-firm contracts exist and are allowed to submit corresponding curtailment offers or non-curtailment bids. The objective of the examples given in this section is to illustrate that the system operation can be improved when the SO schedules both firm and non-firm contracts simultaneously.

In this section only low curtailment offers and non-curtailment bids are considered. The benefits of low curtailment offers for firm contracts have already been made clear in the previous sections. The non-curtailment bids of non-firm contracts are also low because non-firm contracts are in an even more risky position when submitting high non-curtailment bids. With high non-curtailment bids, it may be economical for the

SO to schedule non-firm contracts even though these may lead to congested operation. The non-firm contract trading partners would then be faced with both high power transfer payments and high non-curtailment payments.

As in the previous section, the market clearing solution is analyzed first, followed by discussions on the financial performance measures under both Purchased Firm Bilateral Status and First-Come-First-Serve Firm Bilateral Status.

Market Clearing Solution Characteristics

It is assumed again that all loads have requested to be supplied by bilateral contracts, with the following values for approved firm and requested non-firm bilateral contracts,

$$\mathbf{GDF}^{app} = \begin{bmatrix} 32.3 & 48.4 & 32.3 & 145.4 & 161.5 \\ 0 & 32.3 & 32.3 & 113.1 & 242.3 \\ 0 & 0 & 48.5 & 48.5 & 96.9 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW,} \tag{5.58}$$

$$\mathbf{GDNF}^{req} = \begin{bmatrix} 1.7 & 2.6 & 1.7 & 7.6 & 8.5 \\ 0 & 1.7 & 1.7 & 5.9 & 12.7 \\ 0 & 0 & 2.5 & 2.5 & 5.1 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW} \tag{5.59}$$

Thus, $\mathbf{GDF}^{app}$ composes 95%, and $\mathbf{GDNF}^{req}$ 5% of the total planned bilateral contracts. The nodal demands are the same as in the previous cases as defined by (5.45).

The respective curtailment offers and non-curtailment bids are,

$$\mathbf{bf} = \begin{bmatrix} 1.7 & 2.4 & 0.6 & 0.8 & 1 \\ - & 0.5 & 0.7 & 1.7 & 1.6 \\ - & - & 1.3 & 2 & 2.2 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix} \text{ \$/MWh,} \tag{5.60}$$

$$\mathbf{bnf} = \begin{bmatrix} 0.34 & 0.46 & 0.08 & 0.20 & 1.01 \\ - & 0 & 0.12 & 0.24 & 0.36 \\ - & - & 0 & 0.38 & 0.50 \\ - & - & - & - & - \\ - & - & - & - & - \end{bmatrix} \text{\$/MWh}. \qquad (5.61)$$

The assumption for the above offers and bids is that both bilateral parties, generator and load, submit equal curtailment offers and non-curtailment bids, so that, $bf_{gij} = bf_{dij} = bf_{ij}/2$ and $bnf_{gij} = bnf_{dij} = bnf_{ij}/2$. As for the values of payments offered by the bilateral contracts to acquire firm status, they are again assumed to be 10% of the bilateral contract price defined in (4.23).

The market clearing solution of Case II given in Table 5-20 is compared with Case C and with Case I-i with only firm bilateral contracts and low curtailment offers. This is done from the perspectives of:

- system operation;
- contract curtailments; and
- cost and nodal prices.

System Operation

In comparison with Case C, the system operation in Case II has improved as follows: although generator 1 is still operating at its lower bilateral limit, generator 2 is now free, and as Figure 5-8 illustrates no line is congested. Similarly to Cases I-i and I-iii, the dispatch is still slightly "out of merit", but the congestion of line 1-4 that occurs in Cases C and I-ii with high curtailment offers is now eliminated.

Contract Curtailments

The values of the scheduled firm and non-firm contracts are now, Curtailed by 100 % Curtailed by 0.5 %

$$\mathbf{GDF} = \begin{bmatrix} 32.3 & 48.4 & 0 & 144.6 & 161.5 \\ 0 & 32.3 & 32.3 & 113.1 & 242.3 \\ 0 & 0 & 48.5 & 48.5 & 96.9 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW} \tag{5.62}$$

Curtailed by 100 %

$$\mathbf{GDNF} = \begin{bmatrix} 0 & 0 & 0 & 0 & 8.5 \\ 0 & 1.7 & 1.7 & 5.9 & 12.7 \\ 0 & 0 & 2.5 & 2.5 & 5.1 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{ MW} \tag{5.63}$$

Comparison of (5.58) and (5.62) shows that the firm bilateral contract GDF_{13} is 100% curtailed, while GDF_{14} has also been reduced, but only slightly (0.5%). For non-firm contracts, comparing (5.59) and (5.63), all of the agreements of generator 1 are fully curtailed, except for $GDNF_{15}$, which is fully scheduled. Both the firm and non-firm contracts of the other generators are entirely honored. This result is not surprising, and is similar to the one obtained in Case I-a. Essentially, the contracts most responsible for congestion and "out of merit" dispatch originate from generator 1 and thus are curtailed.

Furthermore, the scheduled contract modifications are consistent with the curtailment offers and non-curtailment bids in (5.60) and (5.61), in other words, as expected, the dispatching procedure does not curtail contracts if this does not improve system operation. Thus, bilateral parties may feel safe that with reasonable offers the market clearing procedure will not curtail them unnecessarily. Nonetheless, as mentioned above, non-firm contract have to be cautious about submitting high non-curtailment bids, as they face a double disincentive, one coming from high power transfer payments and the other from high non-curtailment payments.

Cost and Nodal Prices

As Table 5-20 indicates, the total cost of 34,928 \$/h for Case II is the same as in Cases I-i and I-iii with low or negative offers and lower than the costs of Cases C and I-ii. The power transfer rates are now,

$$\{\lambda_j - \lambda_i\} = \begin{bmatrix} 0 & 0.3 & 1.9 & 2.9 & 6.1 \\ -0.3 & 0 & 1.5 & 2.6 & 5.7 \\ -1.9 & -1.5 & 0 & 1 & 4.2 \\ -2.9 & -2.6 & -1 & 0 & 3.5 \\ -6.1 & -5.7 & -4.2 & -3.5 & 0 \end{bmatrix} \text{\$/MWh} \qquad (5.64)$$

and they are considerably lower than those found in Case C.

Financial Performance Measures

These measures are now discussed for the Purchased Firm Bilateral Status (Case II-i-a) and for the First-Come-First-Serve Firm Bilateral Status (Case II-i-b), the details of which are found in Table 5-21 - Table 5-26. Similarly to discussion on cases with only firm bilateral contracts, here a sub-set of financial performance measures are summarized in Table 5-3 so as to facilitate the comparison of the various cases simulated. The structure of Table 5-3 is the same as for the Table 5-2, that is financial measures associated with generators are given rows 1-7, those associated with loads are in rows 8-14, while row 15 shows the values of merchandising surplus.

Cases II-i-a and II-i-b are then compared from the perspectives of:

- generator revenue components and corresponding rates;
- load expenditure components and corresponding rates;
- merchandising surplus;
- net prices of bilateral trades.

	Case C Firm bilateral trades with <u>no curtailment</u>	*Case II-i* Firm and non-firm bilateral trades with <u>low</u> curtailment offers	
	First-Come-First-Serve firm bilateral status	***Case II-i-a*** Purchased firm bilateral status	***Case II-i-b*** First-Come-First-Serve firm bilateral status
1	$\mathbf{Ef}^{app}=0$	$\mathbf{Ef}_g^{app}=\begin{bmatrix}730\\664\\248\\0\\0\end{bmatrix}$	$\mathbf{Ef}^{app}=0$
2	$\mathbf{R}_g=\begin{bmatrix}-6{,}514\\6{,}045\\6{,}131\\1{,}620\\0\end{bmatrix}$	$\mathbf{R}_g=\begin{bmatrix}13{,}445\\14{,}813\\8{,}681\\0\\0\end{bmatrix}$	$\mathbf{R}_g=\begin{bmatrix}14{,}166\\15{,}477\\8{,}929\\0\\0\end{bmatrix}$
3	$\mathbf{R}_g./\mathbf{P}_g=\begin{bmatrix}-14.7\\13.7\\27.7\\57.6\\0\end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g=\begin{bmatrix}34.5\\31\\32.9\\0\\0\end{bmatrix}$	$\mathbf{R}_g./\mathbf{P}_g=\begin{bmatrix}35.9\\32.4\\33.9\\0\\0\end{bmatrix}$
4	$\tilde{\mathbf{R}}_g^b=\begin{bmatrix}-6{,}513\\6{,}045\\5{,}415\\0\\0\end{bmatrix}$	$\tilde{\mathbf{R}}_g^b=\begin{bmatrix}13{,}471\\13{,}612\\6{,}495\\0\\0\end{bmatrix}$	$\tilde{\mathbf{R}}_g^b=\begin{bmatrix}14{,}191\\14{,}276\\6{,}744\\0\\0\end{bmatrix}$
5	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p=\begin{bmatrix}-14.7\\13.7\\26.5\\0\\0\end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p=\begin{bmatrix}34.1\\30.8\\31.8\\0\\0\end{bmatrix}$	$\tilde{\mathbf{R}}_g^b./\mathbf{P}_g^p=\begin{bmatrix}35.9\\32.3\\33.1\\0\\0\end{bmatrix}$
6	$\mathbf{R}_g^p=\begin{bmatrix}0\\0\\716\\1{,}620\\0\end{bmatrix}$	$\mathbf{R}_g^p=\begin{bmatrix}0\\1{,}247\\2{,}198\\0\\0\end{bmatrix}$	$\mathbf{R}_g^p=\begin{bmatrix}0\\1{,}247\\2{,}198\\0\\0\end{bmatrix}$

Table 5-3. Summary of financial performance characteristics for Case II examples

	Case C	Case II-i-a	Case II-i-b
7	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 0 \\ 35.1 \\ 57.1 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 35.3 \\ 36.9 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{R}_g^p./\mathbf{P}_g^p = \begin{bmatrix} 0 \\ 35.3 \\ 36.8 \\ 0 \\ 0 \end{bmatrix}$
8	$\mathbf{Ef}^{app} = 0$	$\mathbf{Ef}_d^{app} = \begin{bmatrix} 0 \\ 91.3 \\ 116.2 \\ 550 \\ 884 \end{bmatrix}$	$\mathbf{Ef}^{app} = 0$
9	$\mathbf{E}_d = \begin{bmatrix} 1{,}128 \\ 4{,}985 \\ 6{,}338 \\ 24{,}371 \\ 35{,}619 \end{bmatrix}$	$\mathbf{E}_d = \begin{bmatrix} 1{,}277 \\ 3{,}179 \\ 4{,}924 \\ 12{,}523 \\ 20{,}978 \end{bmatrix}$	$\mathbf{E}_d = \begin{bmatrix} 1{,}277 \\ 3{,}088 \\ 4{,}188 \\ 11{,}973 \\ 20{,}093 \end{bmatrix}$
10	$\mathbf{E}_d./\mathbf{P}_d = \begin{bmatrix} 37.7 \\ 58.6 \\ 53.3 \\ 75.4 \\ 67.6 \end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d = \begin{bmatrix} 37.5 \\ 37.4 \\ 36.1 \\ 38.8 \\ 39.8 \end{bmatrix}$	$\mathbf{E}_d./\mathbf{P}_d = \begin{bmatrix} 37.5 \\ 36.3 \\ 35.2 \\ 37.1 \\ 38.1 \end{bmatrix}$
11	$\tilde{\mathbf{E}}_d^b = \begin{bmatrix} 1{,}281 \\ 4{,}985 \\ 6{,}338 \\ 24{,}371 \\ 35{,}619 \end{bmatrix}$	$\tilde{\mathbf{E}}_d^b = \begin{bmatrix} 1{,}217 \\ 3{,}089 \\ 3{,}040 \\ 12{,}196 \\ 20{,}905 \end{bmatrix}$	$\tilde{\mathbf{E}}_d^b = \begin{bmatrix} 1{,}217 \\ 2{,}998 \\ 2{,}933 \\ 11{,}646 \\ 20{,}021 \end{bmatrix}$
12	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b = \begin{bmatrix} 37.7 \\ 58.6 \\ 53.3 \\ 75.4 \\ 67.6 \end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b = \begin{bmatrix} 37.7 \\ 37.5 \\ 35.8 \\ 38.8 \\ 40 \end{bmatrix}$	$\tilde{\mathbf{E}}_d^b./\mathbf{P}_d^b = \begin{bmatrix} 37.7 \\ 36.4 \\ 34.5 \\ 37 \\ 38 \end{bmatrix}$
13	$\mathbf{E}_d^p = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{E}_d^p = \begin{bmatrix} 59.5 \\ 90.1 \\ 1{,}253 \\ 317.8 \\ 0 \end{bmatrix}$	$\mathbf{E}_d^p = \begin{bmatrix} 59.5 \\ 90.1 \\ 1{,}253 \\ 317.7 \\ 0 \end{bmatrix}$
14	$\mathbf{E}_d^p./\mathbf{P}_d^p = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p = \begin{bmatrix} 35 \\ 35.3 \\ 36.9 \\ 37.9 \\ 0 \end{bmatrix}$	$\mathbf{E}_d^p./\mathbf{P}_d^p = \begin{bmatrix} 35 \\ 35.3 \\ 36.9 \\ 37.9 \\ 0 \end{bmatrix}$
15	$MS = 65{,}312$	$MS = 5{,}311$	$MS = 2{,}046$

Table 5-3. Summary of financial performance characteristics for Case II examples (cont.)

Generator Revenue Components and Corresponding Rates

Comparison of results from Table 5-3 for Cases II-i-a, II-i-b with those for Case C indicates that the generator revenues and rates of revenues increased under the presence of non-firm bilateral contracts. Moreover, the results are similar to those of cases with only firm bilateral contracts and low curtailment offers of Table 5-3. Generators 1, 2 and 3 are all slightly better off in this Case II-i-a with non-firm contracts than in Case I-i-a. For instance, the total revenue of generator 1 in this case is 13,445 \$/h in comparison with 13,442 in Case I-i-a. For Case II-i-b with First-Come-First-Serve Firm Bilateral Status, the results are mixed, as generators 1 and 3 are better off in Case II-i-b, while generator 2 is worse off since its revenue decreased from 15,481 4/h to 14,813 \$/h. The differences however are not significant.

If compared mutually, the results are better for the case with the First-Come-First-Serve Firm Bilateral Status as curtailment offers earned under the Purchased Firm Bilateral Status are below payments for acquiring that status (Table 5-21).

Load expenditure components and corresponding rates

Similarly to generators, loads are better off under the operation with booth firm and non-firm contracts than in Case C. In addition, financial performance measures defined from the point of view of the loads are very close for corresponding cases with low curtailment offers under the Purchased Firm Bilateral Status and the First-Come-First-Serve Firm Bilateral Status, that is Case II-i-a to Cases I-i-a and I-iii-a, and Case II-i-b to Cases I-i-b and I-i-b.

Merchandising surplus

The values of merchandising surplus (row 15) for cases with firm and non-firm contracts modification, are much better then in Case C, being similar to cases with only firm bilateral contracts and low curtailment offers.

Net prices of bilateral trades

In addition, the net prices of firm and non-firm contracts are given in Table 5-22 andTable 5-23 for the Purchased Firm Bilateral Status and Table 5-25 andTable 5-26 for the First-Come-First-Serve Firm Bilateral Status. These prices are defined from the perspective generators and loads and may help each bilateral party evaluate a particular agreement and compare it with the possible pool trades.

5.6 Concluding Remarks

This extended model allows for better coordination between centralized pool and decentralized bilateral trading by introducing firm and non-firm contracts that may submit corresponding curtailment offers and non-curtailment bids.

Simulation results of this chapter show that the contract flexibility established through curtailment mechanisms, as well as non-firm contracts, can significantly improve the efficiency of system operation, and reduce nodal prices and nodal price differences. Since bilateral parties always face the full impact of power transfer payments that are based on nodal price differences, they have a strong incentive to forfeit their firm transmission access rights and modify initially approved trades so as to avoid expensive congested operation. Furthermore, the flexibility introduced by bilateral curtailment offers can improve financial performance measures of all market participants, and not only those directly involved in curtailment offers.

However, it is also important to stress that the system operation can be improved under curtailment only to the extent permitted by the market participants themselves and according to the values of their offers. For example, with all offers equal to zero, the generation dispatch will be the same as if there were no contracts, as enough contract curtailment will take place to eliminate "out of merit" operation. On the other hand, high offers may enforce the SO to schedule all the approved, resulting in congested operation and high power transfer payments.

Behaviour of bilateral parties however may depend on the way in which firm bilateral status is obtained. Under the Purchased Firm Bilateral Status bilateral parties acquire Financial Curtailment Rights which entitle them to collect revenue form congestion. If bilateral parties feel that they are in a position to exercise market power and earn from curtailment bids, they may be tempted to submit high curtailment bids and earn from Financial Curtailment Rights. However, getting in such a position may be difficult, and probably does not occur often. In the examples given in this chapter, earnings from high curtailment offers were negated by high power transfer payments, yet we cannot claim that the situation in which curtailment revenues are very high will never or cannot happen.

Thus, to lessen the possibility of gaming by firm bilateral contracts, the First-Come-First-Serve Firm Bilateral Status is also investigated, under which bilateral parties do no pay for the firm status, but are also not entitled to collect curtailment revenue. They still submit curtailment offers, but these now only reflect the degree to which the contract parties are prepared to undergo curtailment to eliminate congestion and out of merit operation. This second approach is also interesting from the perspective of the merchandising surplus collected by the SO, since it has the same value as the originally proposed pool/bilateral market model if only firm bilateral trades without curtailment options are allowed.

Finally, all presented examples illustrate that the power transfer payments indeed send important economic signals to market participants regarding congested operation. Thus, these payments can be used as a useful tool to entice all bilateral parities to carefully plan their bilateral trades, or to submit curtailment offers and non-curtailment bids that will leave sufficient flexibility to the SO to curtail certain trades during market clearing procedure and eliminate congestion.

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	0	0	0	0	0	0
P_d^b $[MW]$	34	85	119	323	527	1,088
P_g $[MW]$	442	442	224	28	0	1,137
P_g^b $[MW]$	442	442	204	0	0	1,088
P_g^p $[MW]$	0	0	0	0	0	0
$I\Theta$ $[\$/MWh]$	37.7	34.3	35.1	57.1	57.0	-
λ_i $[\$/MWh]$	-65.3	9.1	35.1	57.1	54.6	-
π_g^b $[\$/MWh]$	37.7	34.3	34.2	-	-	-
C_g $[\$/h]$	13,147	12,712	7,343	2,004	400	35,606

Table 5-4. Case C: Market clearing dispatch results

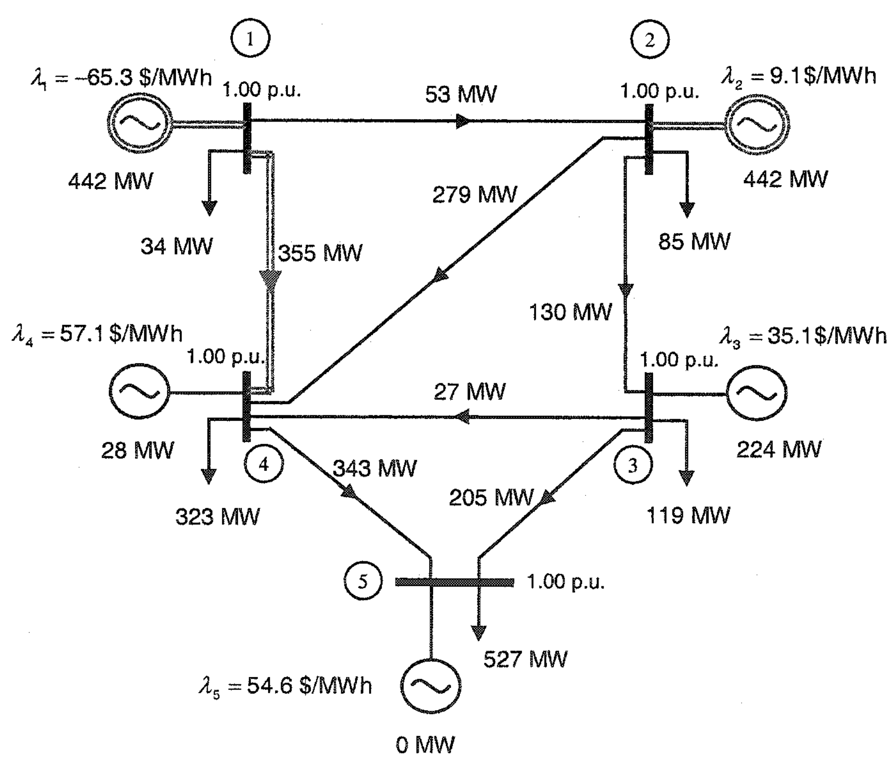

Figure 5-4. Case C: Line flows and nodal prices

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	0	0	34	12.6	0	46.6
P_d^b $[MW]$	34	85	85	310.4	527	1,041
P_g $[MW]$	395.4	477.3	263.6	0	0	1,136
P_g^b $[MW]$	395.4	442	204	0	0	1,041
P_g^p $[MW]$	0	35.3	59.6	0	0	94.9
$I\Theta$ $[\$/MWh]$	37.7	35.3	36.9	56	57	—
λ_i $[\$/MWh]$	35	35.3	36.9	37.9	41.4	—
π_g^b $[\$/MWh]$	37.7	34.3	34.2	—	—	—
C_g $[\$/h]$	11,433	13,941	8,754	400	400	34,928

Table 5-5. Case I-i: Market clearing dispatch results with low curtailment offers

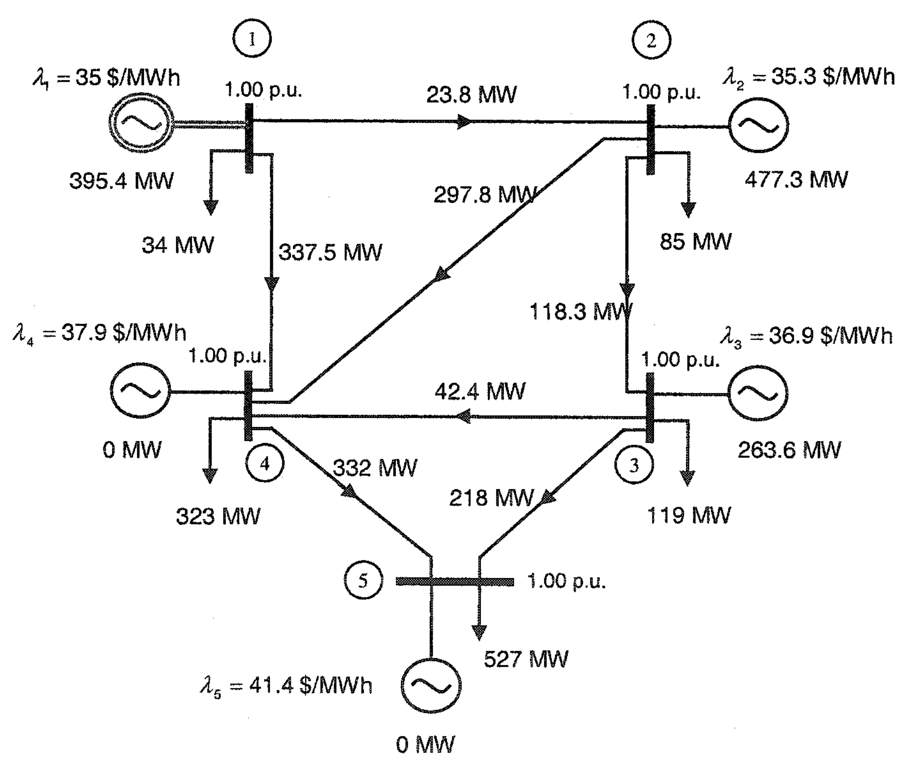

Figure 5-5. Case I-i: Line flows and nodal prices with low curtailment offers

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	0	0	6.2	0	0	6.2
P_d^b $[MW]$	34	85	112.8	323	527	1,082
P_g $[MW]$	435.6	442	259.2	0	0	1,137
P_g^b $[MW]$	435.6	442	204	0	0	1,082
P_g^p $[MW]$	0	0	55.2	0	0	55.2
$I\Theta$ $[\$/MWh]$	37.7	34.3	36.7	56	57	—
λ_i $[\$/MWh]$	-22.6	21	36.7	50.2	50.1	—
π_g^b $[\$/MWh]$	37.7	34.3	34.2	—	—	—
C_g $[\$/h]$	12,913	12,712	8,591	400	400	35,017

Table 5-6. Case I-ii: Market clearing dispatch results with high curtailment offers

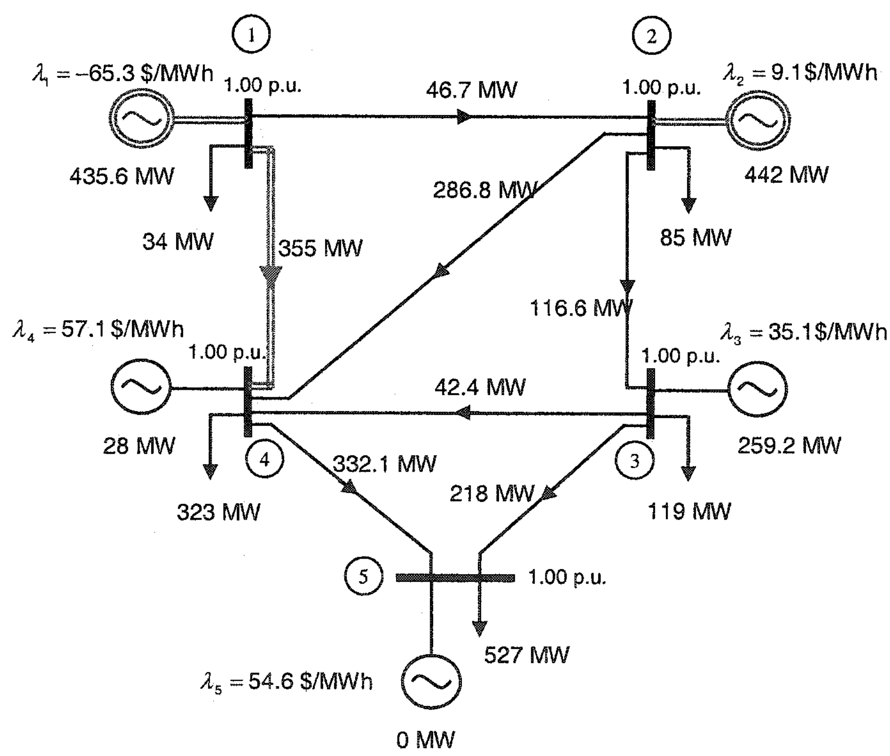

Figure 5-6. Case I-ii: Line flows and nodal prices with high curtailment offers

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	0	0	34	12.6	102	148.6
P_d^b $[MW]$	34	85	85	310.4	425	939.4
P_g $[MW]$	395.4	477.3	263.6	0	0	1,136
P_g^b $[MW]$	395.4	442	102	0	0	939.4
P_g^p $[MW]$	0	35.3	161.6	0	0	197
$I\Theta$ $[\$/MWh]$	37.7	35.3	36.9	56	57	—
λ_i $[\$/MWh]$	35	35.3	36.9	37.9	41	—
π_g^b $[\$/MWh]$	37.7	34.3	34.2	—	—	—
C_g $[\$/h]$	11,433	13,941	8,754	400	400	34,928

Table 5-7. Case I-iii: Market clearing dispatch results with negative curtailment offers

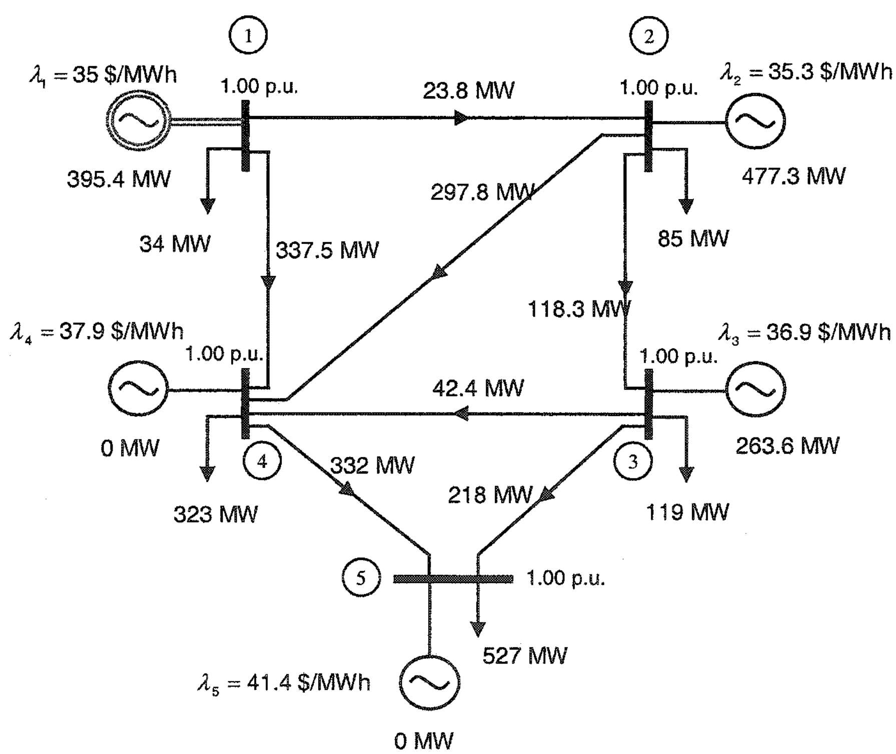

Figure 5-7. Case I-iii: Line flows and nodal prices with negative curtailment offers

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
$R_g^p\ [\$/h]$	0	0	716	1,620	0	2,335
$R_g^b\ [\$/h]$	16,655	15,143	6,973	0	0	38,770
$Ef^{bcl}/2\ [\$/h]$	23,168	9,098	1,558	0	0	33,824
$Ef^{app}/2\ [\$/h]$	0	0	0	0	0	0
$E^{bcl}/2\ [\$/h]$	23,168	9,098	1,558	0	0	33,824
$R_g^f\ [\$/h]$	0	0	0	0	0	0
$R_g\ [\$/h]$	-6,514	6,045	6,131	1,620	0	7,282
$E_d^p\ [\$/h]$	0	0	0	0	0	0
$E_d^b\ [\$/h]$	1,281	3,087	4,189	11,585	18,628	38,770
$Ef^{bcl}/2\ [\$/h]$	0	1,898	2,149	12,786	16,991	33,824
$Ef^{app}/2\ [\$/h]$	0	0	0	0	0	0
$E^{bcl}/2\ [\$/h]$	0	1,898	2,149	12,786	16,991	33,824
$R_d^f\ [\$/h]$	0	0	0	0	0	0
$E_d\ [\$/h]$	1,281	4,985	6,338	24,371	35,619	72,594

Table 5-8. Case C: Financial performance measures

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$
bus # of selling generator	1	37.7	37.7	0.5	74.9	-12.5	87.9	-23.5	99	-22.3	97.6
	2	—	—	34.3	34.3	21.3	47.3	10.3	58.3	11.5	57
	3	—	—	—	—	34.2	34.2	23.2	45.2	24.4	43.9

Table 5-9. Case C: Net prices of firm bilateral contracts

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [$/h]	0	1,247	2,198	0	0	3,444
R_g^b [$/h]	14,897	15,143	6,973	0	0	37,013
$Ef^{bcl}/2$ [$/h]	721.7	909.1	239.4	0	0	1,870
$Ef^{app}/2$ [$/h]	768.7	699	261.5	0	0	1,729
$E^{bcl}/2$ [$/h]	1,490	1,608	500.1	0	0	3,599
R_g^f [$/h]	15.3	0	0	0	0	15.3
R_g [$/h]	13,422	14,782	8,669	0	0	36,873
E_d^p [$/h]	0	0	1,253	478.7	0	1,732
E_d^b [$/h]	1,281	3,087	2,908	11,109	18,628	37,013
$Ef^{bcl}/2$ [$/h]	0	7.8	26.2	378,9	1,457	1,870
$Ef^{app}/2$ [$/h]	0	96.1	122.3	579.3	931.4	1,729
$E^{bcl}/2$ [$/h]	0	103.8	148.5	958.1	2,389	3,599
R_d^f [$/h]	0	0	10.2	5.1	0	15.3
E_d [$/h]	1,281	3,190	4,300	12,541	21,017	42,327

Table 5-10. Case I-i-a: Financial performance measures with low curtailment offers for Purchased Firm Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$
bus # of selling generator	1	37.7	37.7	35.6	39.7	—	—	34.2	41.1	32.8	42.6
	2	—	—	34.3	34.3	31.8	36.7	31.3	37.7	29.9	38.8
	3	—	—	—	—	34.2	34.2	32	36.4	30.4	38

Table 5-11. Case I-i-a: Net prices of firm contracts with low curtailment offers for Purchased Firm Bilateral Status

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [$/h]	0	0	2,024	0	0	2,024
R_g^b [$/h]	16,420	15,143	6,973	0	0	38,536
$Ef^{bcl}/2$ [$/h]	13,684	5,715	1,334	0	0	20,433
$Ef^{app}/2$ [$/h]	768.7	699	261.5	0	0	1,729
$E^{bcl}/2$ [$/h]	14,452	6,414	1,295	0	0	22,162
R_g^f [$/h]	186.8	0	0	0	0	186.8
R_g [$/h]	2,154	8,729	7,701	0	0	18,584
E_d^p [$/h]	0	0	228.3	0	0	228.3
E_d^b [$/h]	1,281	3,087	3,954	11,585	18,628	38,536
$Ef^{bcl}/2$ [$/h]	0	1,112	1,088	7,652	10,581	20,433
$Ef^{app}/2$ [$/h]	0	96.1	122.3	579.3	931.4	1,729
$E^{bcl}/2$ [$/h]	0	1,208	1,211	8,231	11,512	22,162
R_d^f [$/h]	0	0	186.8	0	0	186.8
E_d [$/h]	1,281	4,294	5,207	19,816	30,140	60,739

Table 5-12. Case I-ii-a: Financial performance measures with high curtailment offers for Purchased Firm Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$
bus # of selling generator	1	37.7	37.7	14	61.4	12.5	62.9	-0.6	76	-0.5	75.9
	2	—	—	34.3	34.3	24.7	43.8	17.9	50.6	18	50.5
	3	—	—	—	—	34.2	34.2	25.7	42.7	25.8	43

Table 5-13. Case I-ii-a: Net prices of firm contracts with high curtailment offers for Purchased Firm Bilateral Status

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [\$/h]	0	1,247	5,958	0	0	7,204
R_g^b [\$/h]	14,897	15,143	3,486	0	0	33,527
$Ef^{bcl}/2$ [\$/h]	721.7	909.1	25.9	0	0	1,657
$Ef^{app}/2$ [\$/h]	768.7	699	261.5	0	0	1,729
$E^{bcl}/2$ [\$/h]	1,490	1,608	287.3	0	0	3,386
R_g^f [\$/h]	15.3	0	-25.5	0	0	-10.3
R_g [\$/h]	13,422	14,782	9,131	0	0	37,335
E_d^p [\$/h]	0	0	1,253	478.7	4,187	5,919
E_d^b [\$/h]	1,281	3,087	2,908	11,108	15,142	33,527
$Ef^{bcl}/2$ [\$/h]	0	7.8	26.2	378,9	1,244	1,657
$Ef^{app}/2$ [\$/h]	0	96.1	122.3	579.3	931.4	1,729
$E^{bcl}/2$ [\$/h]	0	103.9	148.5	958.1	2,175	3,386
R_d^f [\$/h]	0	0	10.2	5.1	-25.5	-10.3
E_d [\$/h]	1,281	3,190	4,300	12,541	21,539	42,842

Table 5-14. Case I-iii-a: Financial performance measures with negative curtailment offers for Purchased Firm Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$
bus # of selling generator	1	37.7	37.7	35.6	39.7	—	—	34.2	41.1	32.8	42.6
	2	—	—	34.3	34.3	31.8	36.7	31.3	37.7	29.9	38.8
	3	—	—	—	—	34.2	34.2	32	36.4	—	—

Table 5-15. Case I-iii-a: Net prices of firm contracts with negative curtailment offers for Purchased Firm Bilateral Status

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [$/h]	0	1,247	2,198	0	0	3,444
R_g^b [$/h]	14,897	15,143	6,973	0	0	37,013
$E^{bcl}/2$ [$/h]	721.7	909.1	239.4	0	0	1,870.2
R_g^f [$/h]	0	0	0	0	0	0
R_g [$/h]	14,173	15,481	8,931	0	0	38,587
E_d^p [$/h]	0	0	1,253	478.7	0	1,732
E_d^b [$/h]	1,281	3,087	2,908	11,109	18,628	37,013
$E^{bcl}/2$ [$/h]	0	7.8	26.2	378.9	1,457	1,870
R_d^f [$/h]	0	0	0	0	0	0
E_d [$/h]	1,281	3,094	4,188	11,967	20,086	40,615

Table 5-16 . Case I-i-b: Financial performance measures with low curtailment offers for First-Come-First-Serve Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$
bus # of selling generator	1	37.7	37.7	35.6	39.7	—	—	36.2	39.1	34.7	40.7
	2	—	—	34.3	34.3	33.5	35	33	35.5	31.4	37.1
	3	—	—	—	—	34.2	34.2	33.	37.7	32	36.3

Table 5-17. Case I-i-b: Net prices of firm contracts with low curtailment offers for First-Come-First-Serve Bilateral Status

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [$\$/h$]	0	0	2,024	0	0	2,024
R_g^b [$\$/h$]	16,420	15,143	6,973	0	0	38,536
$E^{bcl}/2$ [$\$/h$]	13,684	5,715	10,334	0	0	20,433
R_g^f [$\$/h$]	0	0	0	0	0	0
R_g [$\$/h$]	2,736	9,428	7,963	0	0	20,127
E_d^p [$\$/h$]	0	0	228.3	0	0	228.3
E_d^b [$\$/h$]	1,281	3,087	3,954	11,585	18,628	38,536
$E^{bcl}/2$ [$\$/h$]	0	1,112	1,088	7,652	10,581	20,433
R_d^f [$\$/h$]	0	0	0	0	0	0
E_d [$\$/h$]	1,281	4,198	5,271	19,237	29,209	59,197

Table 5-18. Case I-ii-b: Financial performance measures with high curtailment offers for First-Come-First-Serve Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$	$\hat{\pi}_{gij}^{bf}$	$\hat{\pi}_{dij}^{bf}$
bus # of selling generator	1	37.7	37.7	15.9	59.5	8.1	67.3	1.3	74.1	1.3	74
	2	—	—	34.3	34.3	26.4	42.1	19.7	48.9	19.1	48.8
	3	—	—	—	—	34.2	34.2	27.4	41	27.4	41

Table 5-19. Case I-ii-b: Net prices of firm contracts with high curtailment offers for First-Come-First-Serve Bilateral Status

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d $[MW]$	34	85	119	323	527	1,088
P_d^p $[MW]$	1.7	2.5	34	8.4	0	46.7
P_d^b $[MW]$	32.3	82.4	85	314.6	527	1,041
P_g $[MW]$	395.4	477.3	263.6	0	0	1,136.3
P_g^b $[MW]$	395.4	442	204	0	0	1,041.4
P_g^p $[MW]$	0	35.3	56.6	0	0	94.9
IC $[\$/MWh]$	35.8	35.3	36.9	56	57	—
π_i $[\$/MWh]$	35	35.3	36.9	37.9	41.4	—
π_g^b $[\$/MWh]$	37.7	34.3	34.2	—	—	—
C_g $[\$/h]$	11,433	13,941	8,754	400	400	34,928

Table 5-20. Case II: Market clearing dispatch results

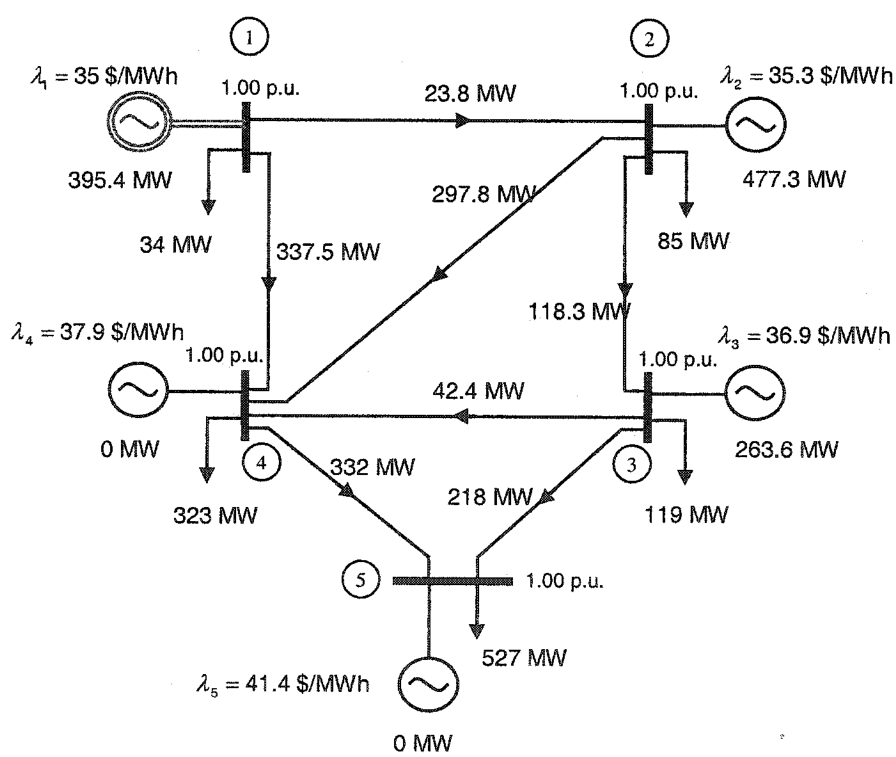

Figure 5-8. Case II: Line flows and nodal prices

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [$/h]	0	1,247	2,198	0	0	3,495
R_g^b [$/h]	14,897	15,143	6,973	0	0	37,012
$Ef^{bcl}/2$ [$/h]	701.7	863.7	227.4	0	0	1,793
$Enf^{bcl}/2$ [$/h]	25.6	45.5	12	0	0	83.1
$Ef^{app}/2$ [$/h]	730.2	664	248.4	0	0	1,643
R_g^f [$/h]	10	0	0	0	0	10
$E^{nf}/2$ [$/h]	4.3	3.2	2.1	0	0	9.6
R_g [$/h]	13,445	14,813	8,681	0	0	36,940
E_d^p [$/h]	59.5	90.1	1,253	317.7	0	1,721
E_d^b [$/h]	1,217	2,990	2,908	11,269	18,628	37,012
$Ef^{bcl}/2$ [$/h]	0	7.4	24.9	376	1,384	1,793
$Enf^{bcl}/2$ [$/h]	0	0	1.3	8.9	72.9	83.1
$Ef^{app}/2$ [$/h]	0	91.3	116.2	550.3	884.4	1,643
R_d^f [$/h]	0	0	9.7	0.3	0	10
$E^{nf}/2$ [$/h]	0	0.1	0.4	1.2	7.9	9.6
E_d [$/h]	1,277	3,179	4,294	12,523	20,987	42,251

Table 5-21. Case II-a: Financial performance measures for Purchased Firm Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$
bus # of selling generator	1	37.7	37.7	35.6	39.7	—	—	34.4	41	32.8	42.5
	2	—	—	34.3	34.3	31.8	36.7	31.3	37.3	29.7	38.8
	3	—	—	—	—	34.2	34.2	32	36.4	30.4	38

Table 5-22. Case II-a: Net prices of firm contracts for Purchased Firm Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$
bus # of selling generator	1	—	—	—	—	—	—	—	—	34.2	41.2
	2	—	—	34.3	34.3	33.4	35.1	32.9	35.7	31.2	37.3
	3	—	—	—	—	34.2	34.2	33.5	34.9	31.8	36.5

Table 5-23. Case II-a: Net prices of non-firm contracts for Purchased Firm Bilateral Status

	Bus 1	***Bus 2***	***Bus 3***	***Bus 4***	***Bus 5***	**Sum**
R_g^p [$\$/h$]	0	1,247	2,198	0	0	3,445
R_g^b [$\$/h$]	14,897	15,143	6,973	0	0	37,013
$Ef^{bcl}/2$ [$\$/h$]	701.7	863.7	227.4	0	0	1,793
$Enf^{bcl}/2$ [$\$/h$]	25.6	45.5	12	0	0	83.1
$Ef^{app}/2$ [$\$/h$]	0	0	0	0	0	0
R_g^f [$\$/h$]	10	0	0	0	0	10
$E^{nf}/2$ [$\$/h$]	4.3	3.2	2.1	0	0	9.6
R_g [$\$/h$]	14,166	15,477	8,929	0	0	38,571
E_d^p [$\$/h$]	59.5	90.1	1,253	317.7	0	1,721
E_d^b [$\$/h$]	1,217	2,990	2,908	11,269	18,628	37,013
$Ef^{bcl}/2$ [$\$/h$]	0	7.4	24.9	376	1,384	1,793
$Enf^{bcl}/2$ [$\$/h$]	0	0	1.3	8.9	72.9	83.1
$Ef^{app}/2$ [$\$/h$]	0	0	0	0	0	0
R_d^f [$\$/h$]	0	0	9.7	0.3	0	10
$E^{nf}/2$ [$\$/h$]	0	0.1	0.4	1.2	7.9	9.6
E_d [$\$/h$]	1,277	3,088	4,188	11,973	20,093	40,619

Table 5-24. Case II-b: Financial performance measures for First-Come-First-Serve Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$	$\hat{\pi}^{bf}_{gij}$	$\hat{\pi}^{bf}_{dij}$
bus # of selling generator	1	37.7	37.7	37.5	37.8	—	—	36.2	39.1	34.7	40.7
	2	—	—	34.3	34.3	33.5	35	33	35.5	31.4	37.1
	3	—	—	—	—	34.2	34.2	33.7	34.7	32.1	36.3

Table 5-25. Case II-b: Net prices of firm contracts for First-Come-First-Serve Bilateral Status

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$	$\hat{\pi}^{bnf}_{gij}$	$\hat{\pi}^{bnf}_{dij}$
bus # of selling generator	1	—	—	—	—	—	—	—	—	34.2	41.2
	2	—	—	34.3	34.3	33.4	35.1	32.9	35.7	31.2	37.3
	3	—	—	—	—	34.2	34.2	33.5	34.9	31.8	36.5

Table 5-26. Case II-b: Net prices of non-firm contracts for First-Come-First-Serve Bilateral Status

Chapter 6.

Service and Cost Unbundling in Combined Pool/Bilateral Model and its Implementation in Pay-as-Bid Pricing

The final chapter of this thesis develops a procedure to decompose (*unbundle*) the generation outputs into a number of distinct services and to calculate their respective costs.

In general, one way to do this unbundling is through pro-rata methods, however, although these are usually easy to apply, they do not account for transmission losses or congestion or the power flows themselves. Moreover, pro-rata methods cannot identify and distinguish certain services such as the supply of losses and congestion management associated with bilateral trades or with pool demand. With pro-rata methods, such services have to be lumped into one single service and cost.

An alternative approach to unbundle the various generation services developed in this chapter, builds on the optimal power flow of the original combined pool/bilateral model defined in (3.8) [91]. The unbundling process follows the Aumann–Shapley approach [3, 4, 89] under which the two load components, pool and bilateral, are first divided into the sum of very small increments. For each load component increment, we can compute the corresponding increments in generation services and corresponding cost increments. Since these increments are small, they are additive and can be separated uniquely according to the service. The method then integrates the separated incremental values along a predefined trajectory to calculate the final unbundled values.

There are two main motivations for this cost unbundling. One is to compare the marginal and the negotiated prices of the unbundled services with their actual average costs. This information would help consumers and suppliers to evaluate discrepancies between what they pay or earn for the service, and what the actual unbundled costs are. The second motivation is its potential application to Pay-as-Bid pricing as an alternative to marginal pricing [92].

Under the Pay-as-Bid approach each generator is paid the amount it requested in its offer. This is in contrast to marginal pricing under which the bus incremental costs define the nodal or locational marginal prices that are then used for generation service pricing as well as to define load payments.

Most electricity markets have adopted marginal pricing with the exception of the new trading agreement in England and Wales that has moved toward the pay-as bid scheme [39]. Recent research suggests that Pay-as-Bid may be beneficial in overcoming some of the problems that arise in the current market operation. For example, there are claims that PAB may reduce price volatility and discourage the exercise of market power [37]. Support for the Pay-as-Bid method however is not uniform as some argue that its application may lead to inefficiency and weaken competition [39, 40].

The Pay-as-Bid rule is typically used to price bilateral contracts since loads pay the generators the pre-negotiated requested price, π_{ij}^{b}. As both the price and the traded amount to which this price applies are known accurately, the Pay-as-Bid pricing for bilateral trades is straightforward. In the case of combined pool/bilateral operation however, the PAB method becomes more complex since a generator provides more than just bilateral power, that is, it also provides power for pool demand, for transmission losses, and for congestion management, each of which usually has a different cost. Then, it becomes necessary to decompose the output of each generator into the sum of the various services that it provides and the corresponding costs. These unbundled generator costs are not marginal costs and are not directly related to the nodal prices. In addition, under PAB, the generator costs must be allocated among the loads and the bilateral trades in order to charge a corresponding amount and recover the costs.

The outline of this chapter is the following: First, the various generation services that exist in the combined pool/bilateral operation and associated costs are defined. Then, in combination with the Aumann–Shapley unbundling procedure, the original pool/bilateral model of Chapters 3 and 4 is applied to calculate the unbundled services and costs and to allocate these among the different market participants. This is followed by the definition of a set of financial performance measures from the perspective of the generators and loads. Following some practical considerations, the unbundling algorithm is applied to some sample networks to illustrate its application in service unbundling and in implementing a Pay-as-Bid pricing method in combined pool/bilateral operation.

6.1 Unbundling Procedure for Generation Services and Offered Costs

In this chapter the original combined pool/bilateral model with only firm bilateral contracts defines the market clearing algorithm. For simplicity, curtailment options and non-firm contracts are not modeled here, although an extension to include this additional flexibility is possible.

6.1.1 Definition of Unbundled Services and Offered Costs

Since in this chapter only firm bilateral contracts exist, the same notation as in Chapters 3 and 4 is used. Thus, the bilateral contract between generator i and load j is here denoted as GD_{ij}.

Recall from Chapter 3 that in a combined pool/bilateral market the net demand at bus j is supplied by two terms, one from long-term bilateral contracts with the pool generators, $P_{dj}^{b}=\sum_{i=1}^{n}GD_{ij}$, and the other from the pool-dispatched spot market, P_{dj}^{p}. Thus, the total demand at bus j is given by,

$$P_{dj}=P_{dj}^{b}+P_{dj}^{p} \tag{6.1}$$

The supply of $P_{dj};\forall j$ requires three discernible services,

- $P_{gi}^{pcl};\forall i$ – generation components that supply the pool demands plus their share of losses and congestion management;
- $P_{gi}^{bcl};\forall i$ – generation components that supply the share of ancillary services required by all bilateral contracts[23];
- $P_{gi}^{b}=\sum_{j=1}^{n}GD_{ij};\forall i$ – generation components that supply the bilateral agreements between generators and loads.

In this chapter, the goal is to separate or unbundle the three services defined above and their respective costs for two reasons: one is to calculate the exact cost of each service so as to compare the cost with the revenue received for the service, while the second reason is to be able to implement Pay-as-Bid pricing in the combined pool bilateral operation and charge for each service the exact amount that it costs to deliver it.

From the above definitions, the generation at bus i is defined as the sum of the three services,

$$P_{gi}=P_{gi}^{pcl}+P_{gi}^{bcl}+P_{gi}^{b}=P_{gi}^{pcl}+P_{gi}^{bcl}+\sum_{j=1}^{n}GD_{ij}, \tag{6.2}$$

Note that since both P_{gi}^{pcl} and P_{gi}^{bcl} are supplied by the pool, the net pool generation component used in the previous chapters is,

$$P_{gi}^{p}=P_{gi}^{pcl}+P_{gi}^{bcl}. \tag{6.3}$$

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[23] A generator with no bilateral contracts can still supply some P_{gi}^{bcl}.

The above three services were not explicitly defined in the previous chapters because under marginal pricing the supply of losses and congestion management for both pool and bilateral contracts is priced at the same nodal price. Under cost unbundling however, it will shown here that for the same MW level the 'pcl' and 'bcl' services have different costs in general.

For each of the three services provided by generator i, the corresponding costs are defined as:

- Θ_{gi}^{pcl} – cost for generating the component P_{gi}^{pcl}.
- Θ_{gi}^{bcl} – cost for generating the component P_{gi}^{bcl}.
- Θ_{gi}^{b} – cost for generating the component $P_{gi}^{b} = \sum_{j=1}^{n} GD_{ij}$.

If the cost offer submitted by generator *i,* is the function, $\Theta_{gi}(P_{gi})$, then the sum of the above three cost components must satisfy,

$$\Theta_{gi}(P_{gi}) = \Theta_{gi}^{pcl} + \Theta_{gi}^{bcl} + \Theta_{gi}^{b}. \qquad (6.4)$$

Since the total generation cost of equation (6.4) is known from the market clearing step, there are two issues to be resolved. One is how to separate $\Theta_{gi}(P_{gi})$ into the three components defined by (6.4). The second is how recover the combined generation costs for each service from the loads and the bilateral contracts.

In a pool/bilateral market however, the role of the generators is more complex than in pure pool markets. Notably, generators do not only sell the above defined services, but are also participants in bilateral contracts and thus are also end users of the services that support bilateral trades. Therefore, all generators must pay a portion of the costs with these ancillary services. For now however, the service costs associated with the bilateral trades are considered the responsibility of the "bilateral contracts", without directly distinguishing between a generator and a load side. In this sense, from the point of view of the bilateral contracts the following cost components are defined,

- $\tilde{\Theta}_{ij}^{bcl}$ – cost component allocated to the bilateral contract GD_{ij}, for the supply of its associated ancillary services.

- Θ_{ij}^{b} – cost component allocated to the bilateral contract between generator i and load j for the supply of GD_{ij}.

Note that although the cost component Θ_{ij}^{b} is associated with the bilateral trade GD_{ij}, this cost component is always paid by load j to generator i. Therefore, from the point of the view of the load, a bilateral cost component, Θ_{dj}^{b}, can be allocated to load j, given by the sum of the costs allocated to all its bilateral contracts,

$$\Theta_{dj}^{b} = \sum_{i=1}^{n} \Theta_{ij}^{b} \tag{6.5}$$

Furthermore, loads also buy from the pool, but for these purchases they are the sole end users of the corresponding generation services, including ancillary services. Thus, the cost components associated with the pool demands are,

- Θ_{dj}^{p} – cost component allocated to load j for the supply of its pool demand, P_{dj}^{p}, plus associated losses and congestion re-dispatch.

6.1.2 Reconciliation of Cost Components

The unbundled costs allocated to the pool demand and to the bilateral contracts must exactly match the unbundled generation cost components,

$$\sum_{i=1}^{n}\left(\Theta_{gi}^{pcl} + \Theta_{gi}^{bcl} + \Theta_{gi}^{b}\right) = \sum_{j=1}^{n} \Theta_{dj}^{p} + \sum_{i,j=1}^{n} \tilde{\Theta}_{ij}^{bcl} + \sum_{j=1}^{n} \Theta_{dj}^{b}\,. \tag{6.6}$$

In addition, for each service there must be a match between the unbundled terms in the generation and load sides. For the supply of pool demand and associated ancillary services the reconciliation condition is,

$$\sum_{i=1}^{n} \Theta_{gi}^{pcl} = \sum_{j=1}^{n} \Theta_{dj}^{p}\,. \tag{6.7}$$

Similarly, for the services received by the bilateral contracts for loss and congestion management we have,

$$\sum_{i=1}^{n} \Theta_{gi}^{bcl} = \sum_{i,j=1}^{n} \tilde{\Theta}_{ij}^{bcl} . \tag{6.8}$$

As for the costs of supplying power to the bilateral contracts, they must satisfy,

$$\sum_{i=1}^{n} \Theta_{gi}^{b} = \sum_{j=1}^{n} \Theta_{dj}^{b} . \tag{6.9}$$

The next section describes in detail how to obtain the unbundled service and cost terms defined above.

6.1.3 Calculation of Unbundled Generation and Cost Components by the Aumann-Shapley Procedure

The unbundling of cost and generation into the terms defined above follows an integration process that modifies the two load components (bilateral and pool) in uniform small increments, one at a time, over a given path[24] as shown in Figure 6-1. For each intermediate value of the load components, the market clearing procedure (equation (3.8)) is solved for all pertinent variables. The path of integration is generally linear starting with all generation and cost variables set to zero and proceeding to the final specified values. This path is characterized by a scalar $t; 0 \le t \le 1$.

Each integration step has three parts as described below:

(1) Bilateral integration sub-step:

- Increase only the bilateral contracts by $d\mathbf{GD}$, keeping $d\mathbf{P}_d^p = \mathbf{0}$.
- Solve the combined pool/bilateral optimal power flow procedure (3.8) with the new load levels. Identify all corresponding values of the bus incremental costs, λ_i, the

[24] The possible integration paths are discussed later in this chapter.

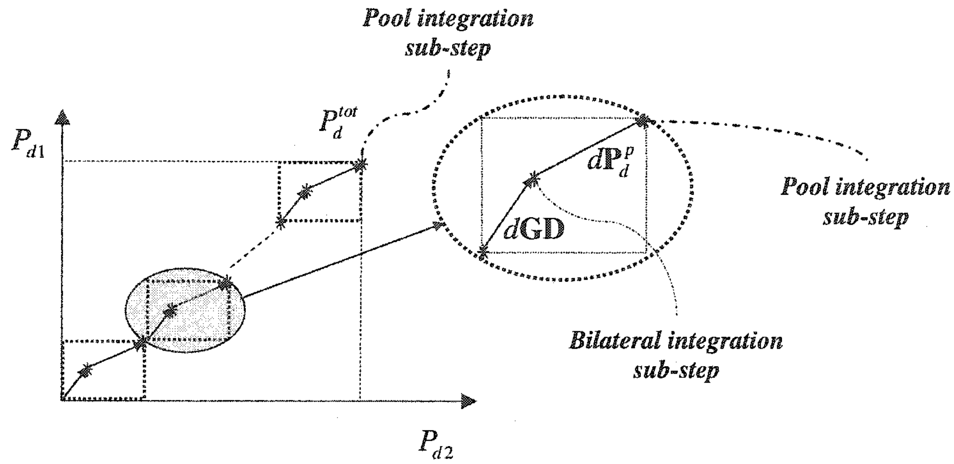

Figure 6-1. Integration process along a predefined path for a two load system

generator incremental costs, $I\Theta_i = \dfrac{d\Theta_{gi}}{dP_{gi}}$, and the increments in the real power optimum dispatch which for this step is denoted by $dP_{gi}\big|_p$, where the symbol $\big|_p$ indicates that the pool demand is kept constant.

- For each generator i calculate the increment in the bilateral loss and congestion re-dispatch service, dP_{gi}^{bcl}. This is found by taking the difference between the increment in the optimum generation and the increment in the bilateral commitments,

$$dP_{gi}^{bcl} = dP_{gi}\Big|_p - \sum_{j=1}^{n} dGD_{ij}\,. \tag{6.10}$$

- Calculate the increments in the service costs from the perspective of all market participants. For generator i, the increment in cost is,

$$d\Theta_{gi} = I\Theta_i \cdot dP_{gi}\Big|_p = I\Theta_i(dP_{gi}^{bcl} + \sum_{j=1}^{n} dGD_{ij}), \tag{6.11}$$

from which we can identify the following unbundled terms,

$$d\Theta_{gi} = d\Theta_{gi}^{bcl} + d\Theta_{gi}^{b}, \tag{6.12}$$

where,

$$d\Theta_{gi}^{bcl} = I\Theta_i \, dP_{gi}^{bcl} , \tag{6.13}$$

and where,

$$d\Theta_{gi}^{b} = \sum_{j=1}^{n} I\Theta_i \cdot dGD_{ij} . \tag{6.14}$$

From, the perspective of the bilateral contracts, if the increment in the cost of generator i for the supply of dGD_{ij} is allocated to the bilateral contract i-j, then,

$$d\Theta_{ij}^{b} = I\Theta_i \cdot dGD_{ij} . \tag{6.15}$$

From the perspective of load j, the allocated incremental cost is therefore the sum of the costs allocated to its bilateral contracts,

$$d\Theta_{dj}^{b} = \sum_{i=1}^{n} d\Theta_{ij}^{b} . \tag{6.16}$$

- Finally, as discussed in Appendix A, the increment in the total generation cost due to the ancillary services provided by all generators to bilateral contract i-j, $d\tilde{\Theta}_{ij}^{bcl}$, can be unbundled into two terms,

$$d\tilde{\Theta}_{ij}^{bcl} = d\Theta_{ij}^{\max} + d\Theta_{ij}^{bcl} \tag{6.17}$$

The first reflects the increment in the total cost attributed to the bilateral contract i-j when the selling generator is operating at its maximum generation level,

$$d\Theta_{ij}^{\max} = -\mu_i^{\max} \, dGD_{ij} . \tag{6.18}$$

As discussed in Appendix A, this cost term reflects the fact that if a generator is operating at its maximum capacity and one of its bilateral contracts changes, then its pool component and those of all other generators will be affected. This effect may occur in mixed pool/bilateral markets even in the absence of transmission losses and congestion.

The second term in (6.17) is the incremental power transfer cost due to the increment in losses and any addition congestion re-dispatch created by dGD_{ij},

$$d\Theta_{ij}^{bcl} = (\lambda_j - \lambda_i)\, dGD_{ij}\,. \tag{6.19}$$

(2) Pool integration sub-step :

- Increase only the pool demand by $d\mathbf{P}_d^p$, while keeping the bilateral contracts constant.
- Solve the combined pool/bilateral optimal power flow procedure (3.8) with the new load levels for all λ_i, $I\Theta_i$ and for the increments in generation, here denoted by $dP_{gi}\big|_b$.
- The generation service component that supplies pool demand together with its associated losses and congestion re-dispatch is,

$$dP_{gi}^{pcl} = dP_{gi}\big|_b\,. \tag{6.20}$$

- Calculate the increments in the service costs from the perspective of all market participants. For generator i, the increment in cost is,

$$d\Theta_{gi}^{pcl} = I\Theta_i\, dP_{gi}^{pcl}\,. \tag{6.21}$$

while for load j, the increment in cost is defined by the bus incremental cost, λ_j, that is,

$$d\Theta_{dj}^{pcl} = \lambda_j\, dP_{dj}^{p}\,. \tag{6.22}$$

(3) Integration of all incremental variables:

The increments calculated above are added over a sufficiently large number of integration steps until both the pool and the bilateral demands reach their final values. The final integrated values define the desired unbundled generation and cost components defined earlier. Thus, denoting dx as any of the above incremental variables, its final integrated value is determined by,

$$x = \int_{t=0}^{1} dx(t) \approx \sum_{k=1}^{N_{steps}} \Delta x_k \,. \tag{6.23}$$

The specific integrated unbundled services and costs are defined in the next section.

6.2 Integrated Unbundled Services and Costs

6.2.1 Unbundled Load Costs

The cost allocated to load j for the supply of its pool component including ancillary services is equal to the integrated value of (6.22),

$$\Theta_{dj}^{pcl} = \int d\Theta_{dj}^{pcl} = \int \lambda_j \, dP_{dj}^{P} \,. \tag{6.24}$$

Also, as defined by (6.15) and (6.16) the unbundled cost allocated to load j for the supply of its bilateral contracts excluding ancillary services is,

$$\Theta_{dj}^{b} = \int \sum_{i=1}^{n} I\Theta_i dGD_{ij} \,. \tag{6.25}$$

6.2.2 Unbundled Costs of the Ancillary Services Required by the Bilateral Trades

Similarly, from the results of Appendix A and from (6.19), the integrated cost of supplying losses and congestion management allocated to the bilateral trade GD_{ij} is,

$$\Theta_{ij}^{bcl} = \int d\Theta_{ij}^{bcl} = \int \left(\lambda_j - \lambda_i\right) dGD_{ij} \,, \tag{6.26}$$

As explained in Appendix A, an additional cost is allocated to the bilateral trade GD_{ij} due to the effect of generator i operating at its maximum limit,

$$\Theta_{ij}^{\max} = -\int \mu_i^{\max} \sum_{j=1} dGD_{ij} \qquad (6.27)$$

6.2.3 Unbundled Generator Costs

The unbundled net cost of generator i for the pool service, P_{gi}^{pcl}, is from (6.11) and (6.21),

$$\Theta_{gi}^{pcl} = \int d\Theta_{gi}^{pcl} = \int I\Theta_i \, dP_{gi}^{pcl} \, . \qquad (6.28)$$

The corresponding unbundled MW service is,

$$P_{gi}^{pcl} = \int dP_{gi}^{pcl} \, . \qquad (6.29)$$

For the generation service that supplies ancillary services for the bilateral trades, P_{gi}^{bcl}, the net unbundled cost to generator i is,

$$\Theta_{gi}^{bcl} = \int d\Theta_{gi}^{bcl} = \int \lambda_i \, dP_{gi}^{bcl} \, , \qquad (6.30)$$

while the corresponding integrated unbundled service is,

$$P_{gi}^{bcl} = \int dP_{gi}^{bcl} \, . \qquad (6.31)$$

The unbundled net cost for the bilateral contracts (excluding ancillary services) of generator i is,

$$\Theta_{gi}^{b} = \sum_{j=1}^{n} \int d\Theta_{gi}^{b} = \sum_{j=1}^{n} \int IC_i \, dGD_{ij} \, . \qquad (6.32)$$

Thus, the total cost to generator i is unbundled according to,

$$\Theta_{gi}(P_{gi}) = \Theta_{gi}^{pcl} + \Theta_{gi}^{bcl} + \Theta_{gi}^{b} \, . \qquad (6.33)$$

6.3 Application of the Unbundling Procedure to Pay-as-Bid Pricing

The above unbundled costs are now implemented in the Pay-as-Bid pricing method for the combined pool/bilateral market. Under Pay-as-Bid, generators are paid the amount that they ask through their offers. These costs are then allocated among the bilateral contracts and pool demands so that their overall payments exactly match the cost to the generators.

In this section a number of financial performance measures of the Pay-as-Bid approach are defined from the point of view of both generators and loads.

6.3.1 Generator Revenues and Expenditures

Under PAB, the revenue of generator i for supplying the pool services, P_{gi}^{pcl}, is equal to the cost of providing these services (6.28) that is,

$$R_{gi}^{pcl} = \Theta_{gi}^{pcl} . \tag{6.34}$$

The average selling price associated with this unbundled service is defined by the ratio of the revenue and the corresponding MW service,

$$\hat{\pi}_{gi}^{pcl} = \frac{R_{gi}^{pcl}}{P_{gi}^{pcl}} . \tag{6.35}$$

For the generation service that supplies losses and congestion re-dispatch associated with the bilateral trades, P_{gi}^{bcl}, generator i collects a total revenue given by,

$$R_{gi}^{bcl} = \Theta_{gi}^{bcl} , \tag{6.36}$$

at an average selling price of,

$$\hat{\pi}_{gi}^{bcl} = \frac{R_{gi}^{bcl}}{P_{gi}^{bcl}}. \tag{6.37}$$

The revenue of generator i for its privately negotiated bilateral contracts (excluding ancillary services) depends on the pre-negotiated price, π_{ij}^{b}, that is,

$$R_{gi}^{b} = \sum_{j=1}^{n} \pi_{ij}^{b} GD_{ij}. \tag{6.38}$$

In general this revenue is not equal to the corresponding unbundled cost quantity given in (6.32), that is,

$$R_{gi}^{b} \neq \Theta_{gi}^{b}. \tag{6.39}$$

As before, the average unbundled bilateral selling price is defined as,

$$\hat{\pi}_{gi}^{b} = \frac{\Theta_{gi}^{b}}{P_{gi}^{b}} \tag{6.40}$$

The comparison between the true revenue, R_{gi}^{b}, and the unbundled bilateral cost term, Θ_{gi}^{b}, is useful information for the generator to evaluate the profitability of its bilateral trades, as the latter indicates the possible earnings had the same bilateral exchange been priced according to $\hat{\pi}_{gi}^{b}$. In addition, if the generator had submitted its true cost for pool generation, then the unbundled bilateral cost, Θ_{gi}^{b}, also reveals the true cost for supplying the bilateral trades.

In addition to the revenues described above, generators are also allocated two expenditure terms. One is due to the overall losses and congestion management required by its bilateral trades, while the second is due to the effect on the system cost of operating at maximum generation output, both services that are provided by all generators in the pool. Thus, in keeping with the policy that both buyer and seller are equally responsible for the power transfer expenses, half of the cost allocated to the bilateral contract i-j for losses and congestion management as defined by equation (6.26) is allocated to generator

i as an expenditure, with the other half allocated to load j. Summing over all contracts, the total expenditure allocated to generator i becomes,

$$E_{gi}^{bcl} = \frac{1}{2}\sum_{j=1}^{n}\Theta_{ij}^{bcl}. \tag{6.41}$$

The average price of losses and congestion management for the power transfer of each bilateral trade under PAB can then be defined as,

$$\hat{\pi}_{ij}^{bcl} = \frac{\Theta_{ij}^{bcl}}{GD_{ij}}. \tag{6.42}$$

This PAB price is analogous to the nodal price difference, $\lambda_j - \lambda_i$, that bilateral contracts pay for power transfer payments under marginal pricing. As $\hat{\pi}_{ij}^{bcl}$ indicates the exact rate seen by the SO for the generation of these services, this rate comparison can be used to evaluate whether the marginal pricing method is relatively more expensive or cheaper than the unbundled rate.

Furthermore, the unbundling procedure has also identified the additional cost, $\Theta_{ij}^{\max}$, that arises if the selling generator in a bilateral trade i-j operates at its maximum limit. This cost term, defined in (6.27), could be attributed to the bilateral contract, however we argue here that all the $\Theta_{ij}^{\max}$ costs should instead be allocated to the generator that operates at its maximum output level, and is the cause of this extra cost. This then defines an additional expenditure allocated to generator i,

$$E_{gi}^{\max} = \sum_{j=1}^{n}\Theta_{ij}^{\max} \tag{6.43}$$

Taking now into consideration both the bilateral and the average price of losses and congestion re-dispatch, as well as the expenditure due to operation at maximum generation, the net price of each bilateral trade seen by generator i becomes,

$$\hat{\pi}_{gij}^{b} = \pi_{ij}^{b} - \frac{\hat{\pi}_{ij}^{bcl}}{2} - \hat{\mu}_{i}^{\max}. \tag{6.44}$$

where,

$$\hat{\mu}_i^{\max} = \frac{\Theta_{ij}^{\max}}{GD_{ij}} \tag{6.45}$$

Finally, the net revenue of generator i is,

$$R_{gi} = R_{gi}^{pcl} + R_{gi}^{bcl} + R_{gi}^{b} - E_{gi}^{bcl} - E_{gi}^{\max}. \tag{6.46}$$

6.3.2 Load Revenues and Expenditures

Similarly to the generators, the expenditure of load j for pool demand under PAB is equal to the unbundled value of this service defined by (6.24),

$$E_{dj}^{pcl} = \Theta_{dj}^{pcl}, \tag{6.47}$$

with an average buying price given by,

$$\hat{\pi}_{dj}^{p} = \frac{E_{dj}^{p}}{P_{dj}^{p}}. \tag{6.48}$$

Note that under PAB this buying price is not the same as the average selling price associated with the pool generation at the same bus, $\hat{\pi}_{gj}^{p}$.

The privately negotiated load payments for the bilateral contracts (excluding ancillary services) are defined by the pre-negotiated bilateral price which is independent of the market clearing procedure, so that,

$$E_{dj}^{b} = \sum_{i=1}^{n} \pi_{ij}^{b} GD_{ij}. \tag{6.49}$$

Again, in general this payment is not equal to the corresponding unbundled cost quantity defined by (6.25)

$$E_{dj}^{b} \neq \Theta_{dj}^{b}. \tag{6.50}$$

The average unbundled bilateral price seen by the load is then,

$$\hat{\pi}_{dj}^{b} = \frac{\Theta_{dj}^{b}}{P_{dj}^{b}} \tag{6.51}$$

Furthermore, since the power transfer payments of bilateral contracts Θ_{ij}^{bcl} as defined by equation (6.26) are split equally between generators and loads, the expenditure of load j for these services is,

$$E_{dj}^{bcl} = \frac{1}{2}\sum_{i=1}^{n}\Theta_{ij}^{bcl}, \tag{6.52}$$

Considering all load payments associated with bilateral trading, the net buying price of each bilateral trade seen by the load is,

$$\hat{\pi}_{dij}^{b} = \pi_{ij}^{b} + \frac{\hat{\pi}_{ij}^{bcl}}{2}. \tag{6.53}$$

where $\hat{\pi}_{ij}^{bcl}$ is the average price of losses and congestion management defined by (6.42).

From the previous equations, the total expenditure of load j is then,

$$E_{dj} = E_{dj}^{pcl} + E_{dj}^{b} + E_{dj}^{bcl}. \tag{6.54}$$

The monetary and information flows associated with these financial performance measures under the Pay-as-Bid approach are illustrated in Figure 6-2.

6.3.3 Merchandising Surplus

An important feature of the Pay-as-Bid method is that end users pay exactly what it costs to compensate the generators for their supply, so that there is no merchandising surplus.

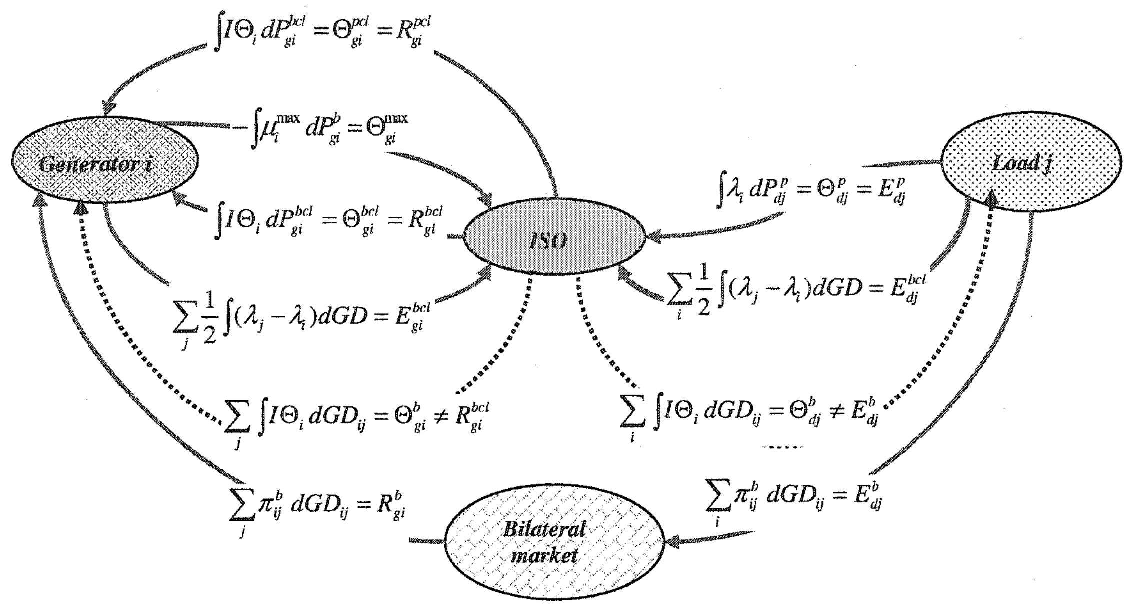

Figure 6-2. Monetary and information flows under the Pay-as-Bid method

6.4 Practical Considerations in the Unbundling Process

Two issues are relevant here. The first is the dependence of the unbundling process on the path of integration. The second concerns the number of integration steps along that path.

Regarding the path of integration, three possibilities could be defined: (a) Incrementally increasing the pool demands from zero to their final values, followed by the same procedure for the bilateral demands; (b) Incrementally increasing the bilateral demands from zero to their final values, followed by the same procedure for the pool demands; (c) Alternating the increase in the bilateral and pool demands, one step at a time.

In the simulation results of this chapter the third approach is applied starting with an increase in the bilateral demands as illustrated in Figure 6-1[27]. The drawback of the other two alternate paths is that the service that is integrated first is allocated relatively low losses and congestion management costs, while those integrated last are allocated a higher proportion of losses and congestion management services and costs. The choice of the integration path should be part of the market rules.

As the number of integration steps diminishes, the final sum of the incremental variables differs from the exact values. Specifically, equations (6.4), and (6.7)-(6.9) are only approximately met. Such errors are inevitable if we wish to limit the number of integration steps to a reasonable number. However, the impact of these errors can be limited by distributing them in a pro-rata manner among the unbundled quantities.

6.5 Simulation Results

The analysis of the unbundling of generation services and costs considers the same network as in the previous chapters (whose data are given in Appendix C). Again, only Case C of Chapter 4 with the entire load supplied solely through bilateral trades (no pool demand) is examined here[29]. Similarly to Case C, there is no curtailment of bilateral trades. Thus, the pool only provides ancillary services associated with the bilateral contracts.

As in Chapter 4, the following assumptions apply here,

- the bus voltage magnitudes of the transmission network are assumed fixed at one per unit by sufficient VAr sources;
- the total value of bus demands (combined pool and bilateral) are considered inelastic;

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[27] The final values of the unbundled service variables are not be affected by the order in which the services are considered within the integration sequence, provided that the integration steps are sufficiently small.

[29] In the rest of the text, when referring to "Case C", it will be understood that it is Case C from Chapter 4.

- the bilateral contracts are considered physical, which means that generator i has an obligation to inject the scheduled value into bus i while the consumers at bus j must absorb the same level of power;

The effect of the number of integration steps on the unbundling procedure is illustrated on both the previously specified 5-bus network as well as on a modified IEEE 24-bus system whose data are given in Appendix D.

Finally, the financial performance measures developed in section 6.3 are used to illustrate the application of the Pay-As-Bid pricing method as well as to compare the results with the values obtained under Locational Marginal Pricing as discussed in Chapter 4. In the application of Pay-as-Bid, the pre-negotiated bilateral contract rates supplied by each generator are considered to be the same for all its contracts. These rates are assumed equal to the marginal generation cost of the selling generator evaluated at its total bilateral output, that is,

$$\pi_{ij}^{b} = \frac{d\Theta_i(P_{gi}^{b})}{dP_{gi}}; \quad \forall j. \tag{6.55}$$

where

$$P_{gi}^{b} = \left(\sum_{j=1}^{n} GD_{ij} \right)$$

Unbundled Generation Services and Costs

The total system demand of 1088 MW is split among the network buses according to,

$$\mathbf{P}_d = [34 \quad 85 \quad 119 \quad 323 \quad 527]^T \quad \text{MW}. \tag{6.56}$$

Under the assumption of Case C, there is no pool demand so that $\mathbf{P_d} = \mathbf{GD}^T\mathbf{e}$, with the matrix of firm contracts being defined as,

$$\mathbf{GD} = \begin{bmatrix} 34 & 51 & 34 & 153 & 170 \\ 0 & 34 & 34 & 119 & 255 \\ 0 & 0 & 51 & 51 & 102 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \text{MW.} \qquad (6.57)$$

Recall that in Case C, and therefore also here, the specified pool/bilateral mix caused congestion on line 1-4, as well as out of merit operation of generators 1 and 2 due to their extensive bilateral commitments. However, non of the generators were operating at their maximum output limit.

The results of the unbundling procedure for this congested case are given in Table 6-1 from the perspectives of the generators. As the values of the unbundled generation services show, the total P_g^{bcl} service components (in this example only losses and congestion re-dispatch, since $P_{gi} < P_{gi}^{\max}; \forall i$) add up to 48.7 MW. This loss and congestion re-dispatch service due to the bilateral trades is allocated a corresponding cost by the unbundling procedure, Θ_g^{bcl}, which totals 2,127 \$/h.

	Bus 1	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**	**Sum**
P_g^{pcl} [MW]	0	0	0	0	0	0
P_g^{bcl} [MW]	0	0	20.4	28.3	0	48.7
P_g^{b} [MW]	442	442	204	0	0	1,088
P_g [MW]	442	442	224.4	28.3	0	1,136.7
Θ_g^{pcl} [\$/h]	0	0	0	0	0	0
Θ_g^{bcl} [\$/h]	-2.4	-108.4	634.5	1,604	–	2,127
$\Theta_g^{\max}$ [\$/h]	0	0	0	0	0	0
Θ_g^{b} [\$/h]	12,749	12,318	6,107	0	0	31,176
Θ_g [\$/h]	12,746	12,211	6,742	1,604	–	33,303

Table 6-1. Unbundling from the generators' perspective

Table 6-1 also indicates how the services and costs are split among all generators. For instance, because of congestion, even though it is expensive, generator 4 is scheduled to produce a portion (28.3 MW) of the bilateral loss and congestion management component. On the other hand, generators 1 and 2 do not contribute to this service, as they operate at their lower bilateral limits. However, perhaps surprisingly, the costs of this service, Θ_{gi}^{bcl}, in generators 1 and 2 are not zero but rather negative. This means that these generators pay (rather than collect) for having forced other more expensive generators to supply loss and congestion management services. This is a reasonable economic signal to such generators, inducing them not to over-commit in the bilateral market to the point of causing congestion.

The unbundled costs associated with losses and congestion re-dispatch due to the bilateral trades are given in Table 6-2. As all the demand is supplied bilaterally, only the unbundled bilateral cost component exists, while the pool cost components are all zero. Note that the sum of the unbundled bilateral costs from the point of view of the demands, Θ_d^b, is equal to the sum of the unbundled bilateral costs from the point of view of the generators, $\Theta_g^b = 31{,}176$ \$/h. However, the total generation costs $\Theta_g = 33{,}303$ \$/h are not equal to the total $\Theta_d^p + \Theta_d^b$, the difference being the sum of the costs of losses and congestion re-dispatch, that is, $\Theta_g^{bcl} = 2{,}127$ \$/h. This service is also shown in Table 6-3 from the perspective of the bilateral contracts which, as can be seen, adds up to 2,132 \$/h. For instance, contract $GD_{12} = 51\text{MW}$ pays 46.2 \$/h for losses and congestion management, while contract GD_{34} of the same size pays only 23.4 \$/h. This significant difference is due to the high levels of bilateral trades of generator 1 and the congestion of line 1-4.

Also, for all bilateral contracts, values of $\Theta_{ij}^{\max}$ costs are zero, as all generators operate below their maximum capacity.

Pay-as-Bid Pricing

The values of the revenues and expenditures defined under Pay-as-Bid pricing for this 5-bus congested case are given in Table 6-4. Note that the generator revenues differ from the values of the total generation costs of

Table 6-1. This difference arises because (i) the revenues include the generator payments for bilateral loss and congestion re-dispatch, and (ii) because the actual bilateral

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
P_d^p [MW]	0	0	0	0	0	0
P_d^b [MW]	34	85	119	323	527	1.088
P_d [MW]	34	85	119	323	527	1.088
Θ_d^p [\$/h]	0	0	0	0	0	0
Θ_d^b [\$/h]	981	2,419	3,455	9,257	15,065	31,176

Table 6-2. Unbundling from loads' perspective

		Θ_{ij}^{bcl}				
		bus # of buying load				
		1	2	3	4	5
bus # of selling generator	1	0	46.2	63.5	355.7	601.2
	2	–	0	32.7	168.8	670.8
	3	–	–	0	23.4	170.3

Table 6-3. Unbundling cost for losses and congestion re-dispatch from bilateral contracts' perspective

contract revenues are based on the pre-agreed bilateral contract prices, π_{ij}^b, rather than on the unbundled bilateral service costs, Θ_{gi}^b. The results reveal that the revenues of generators 1, 2 and 3 for supplying bilateral generation services, R_g^b, are higher than the corresponding unbundled bilateral costs, Θ_g^b, from Table 6-1, since the pre-negotiated bilateral rates, π_{ij}^b, are higher than the average unbundled bilateral rate, $\hat{\pi}_{gi}^b$, defined in (6.40). For instance, the bilateral revenue of generator 1, $R_{g1}^b = 16{,}119$ \$/h is higher than the corresponding unbundled bilateral cost, $\Theta_{g1}^b = 12{,}749$ \$/h, as the pre-negotiated bilateral rates, $\pi_{1j}^b = 37.7$ \$/MWh, are higher than the average unbundled rate, $\hat{\pi}_{g1}^b = 28.8$ \$/MWh (given in Table 6-4).

Similarly, the net generator revenues after accounting for all income and expenditures, R_{gi}, are higher than or equal to the total unbundled costs, Θ_{gi}, for all generators. In this example, all the generators clearly negotiated advantageous bilateral deals at the expense of the consumers.

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
$R_g^b \neq \Theta_g^b$ [\$/h]	16,655	15,143	6,973	0	0	38,770
$R_g^{bcl} = \Theta_g^{bcl}$ [\$/h]	-2.4	-108.4	634.5	1,604	–	2,127
$R_g^{pcl} = \Theta_g^{pcl}$ [\$/h]	0	0	0	0	0	0
$R_g^p = \Theta_g^p$ [\$/h]	0	0	0	0	0	0
E_g^{bcl} [\$/h]	533.3	436.2	96.8	0	0	1,066
$R_g^{\max}$ [\$/h]	0	0	0	0	0	0
R_g [\$/h]	16,119	14,598	7,510	1,604	0	39,833
$I\Theta$ [\$/MWh]	37.7	34.3	35.1	57.1	57	–
λ_i [\$/MWh]	-65.3	9.1	35.1	57.1	54.6	–
π_g^b [\$/MWh]	37.7	34.3	35.1	57.1	57	–
$\hat{\pi}_g^{pcl} = \Theta_g^{pcl} / P_g^{pcl}$ [\$/MWh]	0	0	0	0	0	–
$\hat{\pi}_g^{bcl} = \Theta_g^{bcl} / P_g^{bcl}$ [\$/MWh]	0	0	31.1	56.7	0	–
$\hat{\pi}_g^b = \Theta_g^b / P_g^b$ [\$/MWh]	28.8	27.9	30	0	0	–
E_d^b [\$/h]	1,281	3,087	4,189	11,585	18,628	38,770
E_d^{bcl} [\$/h]	0	23.1	48.1	273.9	721.2	1,066
E_d^p [\$/h]	0	0	0	0	0	0
E_d [\$/h]	1,281	3,110	4,237	11,859	19,349	39,835
$\hat{\pi}_d^p = \Theta_d^p / P_d^p$ [\$/MWh]	0	0	0	0	0	–
$\hat{\pi}_d^b = \Theta_d^b / P_d^b$ [\$/MWh]	28.8	28.4	29	28.7	28.6	–

Table 6-4. Pay-as-Bid: Revenues, expenditures and average prices

In addition, it is interesting to compare some of the unbundled service average prices against the nodal prices and the negotiated bilateral price. For instance, the nodal price at bus 3, $\lambda_3 = 35.1$\$/MWh is above the average unbundled bilateral loss and congestion management price of generator 3, $\hat{\pi}_{g3}^{bcl} = 31.1$ \$/MWh for the P_{g3}^{bcl} service. Also, its pre-negotiated bilateral price of $\pi_3^b = 35.1$ \$/MWh is higher that the unbundled average price of bilateral service $\hat{\pi}^b_{g3}$= 30 \$/MWh. The last comparison is a signal to generator 3 that his pre-negotiated rate is good, however the first comparison tells generator 3 that he may do equally well by selling to the pool rather than bilaterally.

From Table 6-4, the net load expenditures for bilaterally purchased power, E^b_{dj}, are above the unbundled costs associated with these services, Θ^b_{dj}. This is not a surprising result considering that the privately negotiated bilateral rates, π^b_{gi}, are above the average unbundled rates of supplying this service, $\hat{\pi}^b_{dj}$. This means that the loads could be better off by buying a portion of their demands from the pool or by re-negotiating their bilateral contracts. For example, the load at bus 5 is buying bilaterally from generators 1, 2 and 3 whose average unbundled bilateral prices, respectively $\hat{\pi}^b_1 = 28.2$, $\hat{\pi}^b_2$=27.9 and $\hat{\pi}^b_3 = 30$ \$/MWh, are lower than what this load is paying, namely the pre-negotiated generator bilateral rates, $\pi^b_{15}= 37.7$, $\pi^b_{25} = 34.3$ and $\pi^b_{35} = 35.1$ \$/MWh. Furthermore, the average rate of the unbundled cost of delivering power to load 5 is $\hat{\pi}^b_{d5}$=28.6 \$/MWh, which is also less than what it is paying. Clearly, the loads did not do a good job of negotiating bilaterally and of specifying an adequate pool/bilateral mix.

It is also interesting to compare the generator revenues and the load expenditures under Pay-as-Bid pricing as given in Table 6-4, with the results of Case C which are calculated under marginal pricing (MP). Both PAB and MP cases are analyzed under identical bus loads and pool/bilateral mixes, as well as cost offers and pre-negotiated bilateral rates. For convenience, the marginal pricing results are repeated here in Table 6-5. From the results of Table 6-4 and Table 6-5 it can be seen that all market participants are better off under PAB, except for generator 4 which is slightly worse off. The most striking difference is in generator 1, whose revenue under marginal pricing is even negative (-6,514 \$/h), while under PAB it actually earns 16,119 \$/h. Similarly, all loads are significantly better off under PAB than under marginal pricing.

The main reason behind these large differences in generator revenues and load expenditures under these two pricing schemes is that under the PAB the market participants are allocated the actual offered cost of generation, Θ_g, whereas under marginal pricing the most expensive generator dictates the nodal prices. The most remarkable difference in rates between the PAB and marginal pricing is reflected in the power transfer payments and their corresponding rates, which for both pricing schemes is compared in Table 6-6. For example, for the bilateral trade GD_{12}, the unbundled rate associated with losses and congestion management, $\hat{\pi}_{12}^{bcl} = 0.9$ \$/MWh, is significantly lower under PAB than the nodal price difference, $\lambda_2 - \lambda_1 = 74.4$ \$/MWh, which this contract pays under marginal pricing. Differences of similar magnitudes between PAB and MP can also be observed for other bilateral contracts as a result of transmission congestion.

	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Sum
R_g^p [\$/h]	0	0	716	1,620	0	2,335
R_g^b [\$/h]	16,655	15,143	6,973	0	0	38,770
$E^{bcl}/2$ [\$/h]	23,168	9,098	1,558	0	0	33,824
R_g^f [\$/h]	0	0	0	0	0	0
R_g [\$/h]	-6,514	6,045	6,131	1,620	0	7,282
E_d^p [\$/h]	0	0	0	0	0	0
E_d^b [\$/h]	1,281	3,087	4,189	11,585	18,628	38,770
$E^{bcl}/2$ [\$/h]	0	1,898	2,149	12,786	16,991	33,824
R_d^f [\$/h]	0	0	0	0	0	0
E_d [\$/h]	1,281	4,985	6,338	24,371	35,619	72,594

Table 6-5. Case C: Revenues and expenditures under marginal pricing

		Pay-as-Bid					Marginal Pricing				
		$\hat{\pi}_{ij}^{bcl}$					$\lambda_j - \lambda_i$				
		bus # of buying load					bus # of buying load				
		1	2	3	4	5	1	2	3	4	5
bus # of selling generator	1	0	0.9	1.9	2.3	3.5	0	74.4	100.4	122.4	120
	2	–	0	1	1.4	2.6	–	0	26	48	45.5
	3	–	–	0	0.5	1.7	–	–	0	22	19.5

Table 6-6. Rates of power transfer payments: Pay-as-Bid vs. Marginal Pricing

The net bilateral rates seen by generators, $\hat{\pi}^b_{gij}$, and loads, $\hat{\pi}^b_{dij}$ under PAB are both given in Table 6-7. These values are defined by and respectively, and reflect both the pre-negotiated bilateral prices and the average unbundled prices of the power transfer payments. The net bilateral rates under marginal pricing, defined by (4.5) and (4.11), are repeated in Table 6-8 for convenience. Their comparison with the PAB rates of Table 6-7 indicates the stronger negative impact of congestion under marginal pricing. For instance, for generator 1, its net bilateral rates, $\hat{\pi}^b_{g1j} = [37.7 \quad 32.7 \quad 36.7 \quad 36.5 \quad 36]$ \$/MWh, are all positive under PAB, whereas under marginal pricing they are very small or even negative, $\hat{\pi}^b_{g1j} = [37.3 \quad 0.5 \quad -12.5 \quad -23.5 \quad -22.3]$ \$/MWh. Similarly for the loads, the net unbundled bilateral rates, $\hat{\pi}^b_{dij}$, under PAB are lower then corresponding net bilateral prices under the marginal pricing. For example, for load 4 under PAB $\hat{\pi}^b_{di4} = [38.8 \quad 35 \quad 34.4 \quad - \quad -]$\$/MWh, while under marginal pricing they take the values of $\hat{\pi}^b_{di4} = [99 \quad 58.3 \quad 45.2 \quad - \quad -]$ \$/MWh.

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$
bus # of selling generator	1	37.7	37.7	32.7	38.1	36.7	38.6	36.5	38.8	36	39.4
	2	–	–	34.3	34.3	33.8	34.7	33.5	35	32.9	35.6
	3	–	–	–	–	34.2	34.2	33.9	34.4	33.3	35

Table 6-7. Pay-as-Bid: Net bilateral prices seen from the perspective of generators and loads

		bus # of buying load									
		1		2		3		4		5	
		$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$	$\hat{\pi}^b_{gij}$	$\hat{\pi}^b_{dij}$
bus # of selling generator	1	37.7	37.7	0.5	74.9	-12.5	87.9	-23.5	99	-22.3	97.6
	2	—	—	34.3	34.3	21.3	47.3	10.3	58.3	11.5	57
	3	—	—	—	—	34.2	34.2	23.2	45.2	24.4	43.9

Table 6-8. Marginal Pricing: Net bilateral prices seen from the perspective of generators and loads

Number of steps

Table 6-9 illustrates the effect of the number of integration steps on the unbundling process. The first row shows the exact value of the sum of the offered generation costs, Θ_g^{exact}, which is independent of the number of steps. Rows 2 and 3 show the integrated estimates of this sum from the perspective of the generators, Θ_g, and from that of the loads, Θ_d, calculated according to the procedure described in section VI. Rows 4 to 7 describe the estimated costs of the unbundled services. These costs have been normalized to ensure that their sum always equals the exact total cost, Θ_g^{exact}. Moreover, a second normalization is done on the cost components associated with the loads so that for each service the cost is the same whether viewed by the loads or by the generators.

Table 6-10 illustrates the effect of the number of integration steps in the unbundling process for a modified IEEE 24-bus system. Comparison of Table 6-9 and Table 6-10 suggests that approximate unbundling is reasonably accurate for all services when at least 100 integration steps are carried out.

	Number of Integration Steps				
	10	100	1000	2000	4000
Θ_g^{exact}	33,306	33,306	33,306	33,306	33,306
Θ_g	32,140	33,189	33,294	33,300	33,303
$\Theta_d + \sum_i \Theta_{ij}^{bcl}$	34,755	33,949	33,293	33,312	33,308
$\hat{\Theta}_g^{pcl} = \hat{\Theta}_d^{pcl}$	0	0	0	0	0
$\hat{\Theta}_g^{b} = \hat{\Theta}_d^{b}$	31,094	31,171	31,178	31,178	31,177
$\hat{\Theta}_g^{bcl} = \hat{\Theta}_d^{bcl}$	2,212	2,135	2,128	2,128	2,128

Table 6-9. Unbundled costs vs. number of integration steps for 5-bus example network

	Number of Integration Steps				
	10	100	1000	2000	4000
Θ_g^{exact}	40,350	40,350	40,350	40,350	40,350
Θ_g	40,023	40,317	40,347	40,348	30,349
$\Theta_d + \sum_i \Theta_{ij}^{bcl}$	39,999	40,318	40,347	40,348	30,349
$\hat{\Theta}_g^{pcl} = \hat{\Theta}_d^{pcl}$	33,413	33,124	33,096	33,096	33,096
$\hat{\Theta}_g^{b} = \hat{\Theta}_d^{b}$	6,936	7,229	7,257	7,257	7,257
$\hat{\Theta}_g^{bcl} = \hat{\Theta}_d^{bcl}$	0.87	-3.37	-3.84	-3.84	-3.84

Table 6-10. Unbundled costs vs. number of integration steps for modified IEEE 24bus system with 83% of pool and 17% bilateral supply

6.6 Concluding Remarks

The above results indicate that in the combined pool/bilateral model service and cost unbundling are useful tools for both generators and loads to evaluate the fraction of the total cost associated with the supply of various generation services. From these unbundled costs it is possible to define a set of average unbundled prices and compare them with the actual prices used to settle the market or with the prices of the bilateral trades. This comparison can be used by market participants to refine their future bilateral strategies, including rates, trading partners and levels of pool/bilateral mix.

In the context of Pay-as-Bid pricing, the unbundled costs and services are used to define a set of financial performance measures, that is, revenues and expenditures from the point of view of individual generators and loads. These measures are then compared with the corresponding revenues and expenditures calculated under marginal pricing. The results for the case when high levels of bilateral trades cause transmission congestion suggest that the Pay-as-Bid approach is beneficial for both loads and generators due to the absence of a merchandising surplus, which significantly reduces the power transfer payments.

Chapter 7.

Conclusions

This thesis develops an optimization model that can be used to clear combined pool/bilateral electricity markets as well as to evaluate their technical and economic merits. One goal is to provide the various market participants, that is, the generators and loads, with a tool that will help them manage their pool/bilateral portfolio, in other words, to determine relative levels of bilateral and pool commitments that offer a good balance between revenues, expenses and the risk of economic losses. A second simultaneous goal of the optimization model is to maximize social welfare while satisfying power system security, namely, respecting the characteristics of the lossy non-linear power flow problem as well as technical limits on the generation outputs and transmission flows.

The notions of pool and bilateral demand and generation are established first. The problem formulation and optimization are based on the assumption that the scheduled bilateral contracts are physical rather than financial obligations. Physical bilateral contracts always impose lower limits on the generation outputs which, if active, result in inefficient out of merit operation and possible transmission congestion. Bilateral contracts are initially assumed to be firm without the possibility of curtailment (except in emergencies requiring load-shedding) but later in the thesis this condition is relaxed

In addition to the generation outputs, transmission losses and line power flows, the market-clearing optimization procedure yields the bus or nodal incremental costs, which under marginal pricing become the so-called Locational or Nodal Marginal Prices. This model does not allow for the purchase of financial transmission rights that shield the bilateral partners from paying for the actual cost of transmission. In this model the bilateral partners may obtain pre-approved firm bilateral status at an auction, but still face paying for power transfer fees at a rate defined by the actual nodal price differences. The point of view of this thesis is that such power transfer payments are good economic signals to market participants to avoid trades that can cause congested operation.

The nodal prices and price differences are then used to define and calculate individual financial performance measures such as generator revenues and load payments separated according to pool or bilateral trading. The goal of the initial analyses is to evaluate to what degree the relative mix of pool versus bilateral trading influences individual and system performance.

Results of these studies are used to evaluate the potential benefits and difficulties that arise from this mixed operation. Notably, the results have indicated the importance of good planning of the pool/bilateral mix to avoid costly congested operation, particularly due to the power transfer payments paid by the bilateral contracts. This planning, however, is not trivial because of the difficulty of predicting the actual mix and distribution of the pool/bilateral commitments of all participants at the time when the bilateral contracts are being individually negotiated.

To address this problem, this thesis proposes additional dispatch flexibility in the form of: (i) a curtailment procedure that permits holders of firm bilateral contracts to offer voluntarily to reduce their firm bilateral commitments at a price and replace the energy from the pool at the prevailing nodal price; (ii) non-firm contracts where the holders submit non-curtailment bids to avoid curtailment.

These curtailment offers are essentially a decentralized tool that bilateral parties may use to reduce the risk of transmission congestion and high power transfer payments at the time of market-clearing. However, bilateral parties may also use curtailment offers to modify unprofitable trades in their favour.

Non-firm contracts are not subject to pre-approval because they have no transmission rights or obligations until they are scheduled after the market is cleared. Being non-firm, they give additional flexibility to the system operator as they could be curtailed if needed for both economical or security reasons. To increase the likelihood of being dispatched, non-firm contracts may submit non-curtailment bids implying that the parties in a non-firm bilateral contract are willing to pay in order not to be curtailed.

The simulation results here compare combined pool/bilateral operation with and without curtailment flexibility. With bilateral contract curtailment offers and bids, the results point out a significant improvement in the overall technical and financial system operation. For instance, under high levels of bilateral trading, low firm contract curtailment offers give the SO the flexibility to sufficiently curtail certain firm bilateral contracts and eliminate congestion. Even though some firm contracts are curtailed, there is still a significant improvement in the net revenues of individual generators and the net payments of the loads, as both now face much lower power transfer payments.

The results also illustrate that the system operation can be improved under curtailment only to the extent permitted by the offers submitted by the bilateral parties. High curtailment offers may not be wise since they force the SO to schedule the bilateral contracts close to their approved levels even when such a dispatch results in congested operation and high power transfer fees.

Finally, this thesis also presents a technique that allows the unbundling of the total generation into three distinct services, namely, (i) bilateral generation, (ii) supply of ancillary services associated with the bilateral generation, and (iii) the supply of the pool demand plus its associated ancillary services. The technique identifies the costs corresponding to each service from the point of view of the loads and generators following an unbundling algorithm based on the Aumann–Shapley procedure. According to this procedure, the separated services are calculated by integrating the output variables of the optimization problem by varying the demand components in small increments, one service at a time.

The results of the unbundled generation and cost services can be used in two ways: one is to compare the unbundled costs associated with each service with the actual revenues and payments found by the marginal pricing method normally used. This can then determine whether the actual profits and payments for each service are in line with the actual unbundled costs, information that can help in defining future pool/bilateral mixes and the settlement price of privately negotiated bilateral deals. The second application of the unbundling procedure is to define a new pricing structure based on the Pay-as-Bid principle in which dispatched generators are paid for pool services exactly what they offer instead of being paid at the nodal price. Similarly, under Pay-as-Bid, the total payments allocated to the loads sum up to the total generator offer costs. These payments do not depend on the nodal prices.

Simulation results are used to compare the individual revenues and payments as well as the average and marginal prices under the two pricing methods. The results indicate that, for the *same offers*, under congested operation, the market participants are better off under Pay-as-Bid than under Locational Marginal Pricing because under Pay-as-Bid they only pay for the cost of losses as well as generation re-dispatches due to transmission congestion and maximum generation constraints. The merchandising surplus that exists under Locational Marginal Pricing is eliminated under Pay-as-Bid. Note, however, that the above comparison between these two pricing methods does not account for the different offer strategies that generators would use under different pricing rules.

Future extensions

Extensions of the work presented in this thesis could include the following topics:

- A forecasting module that would enable market participants to predict the bilateral trading behavior of other trading agents and the nodal prices;
- Based on the previous module, develop strategic pool/bilateral portfolio management schemes from the points of view of the various market players for both Pay-as-Bid and marginal pricing. Strategic planning defines the offer strategies of generators and the levels of pool/bilateral mix that maximize the welfare (profit) of individual market participants under uncertainty;
- Introduce unit commitment into the combined pool/bilateral model;
- Allow for demand elasticity in the pool demand;
- Define and analyze procedures for auctions that pre-approve firm bilateral status.

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Appendix A

Incremental Power Transfer Payments of Firm Bilateral Contracts

This appendix outlines the derivation of the incremental power transfer payment that a firm bilateral contract GD_{ij} is allocated to cover the costs of those ancillary services needed to support the transfer of GD_{ij} megawatts from point i to point j. For both marginal and Pay-as-Bid pricing, the first step to calculate this payment is to find the marginal cost of transferring this amount power under the market clearing rules.

First, recall from Chapter 3 that both the generation at bus i, P_{gi}, and the load demand at bus j, P_{dj}, can be expressed in terms of the pool and bilateral components as,

$$P_{gi} = P_{gi}^{p} + P_{gi}^{b} = P_{gi}^{p} + \sum_{j=1}^{n} GD_{ij} , \tag{A.1}$$

and,

$$P_{dj} = P_{dj}^{p} + P_{dj}^{b} = P_{dj}^{p} + \sum_{i=1}^{n} GD_{ij} . \tag{A.2}$$

In vector form, this can be written as,

$$\mathbf{P}_g = \mathbf{P}_g^p + \mathbf{P}_g^b = \mathbf{P}_g^p + \mathbf{GD}\cdot\mathbf{e}, \tag{A.3}$$

and

$$\mathbf{P}_d = \mathbf{P}_d^p + \mathbf{P}_d^b = \mathbf{P}_g^p + \mathbf{GD}^T\cdot\mathbf{e} \tag{A.4}$$

where $\mathbf{e}$ is a vector of ones of dimension n.

Using equations (A.3) and (A.4), the market clearing optimization now becomes,

$$\underset{\mathbf{P}_g^p,\boldsymbol{\delta}}{Min} \quad \Theta_g(\mathbf{P}_g^p + \mathbf{GD}\cdot\mathbf{e}) \tag{A.5}$$

$$\begin{array}{lll} s.t. & \mathbf{P}_g^p + \mathbf{GD}\cdot\mathbf{e} - \mathbf{P}_d^p + \mathbf{GD}^T\cdot\mathbf{e} = \mathbf{P}(\boldsymbol{\delta}) & \boldsymbol{\lambda} \\ & -\mathbf{P}_g^p \le \mathbf{0} & \boldsymbol{\mu}^{\min} \\ & \mathbf{P}_g^p + \mathbf{GD}\cdot\mathbf{e} \le \mathbf{P}_g^{\max} & \boldsymbol{\mu}^{\max} \\ & \mathbf{P}_{flow}^{\min} \le \mathbf{P}_{flow}(\boldsymbol{\delta}) & \boldsymbol{\alpha} \\ & \mathbf{P}_{flow}(\boldsymbol{\delta}) \le \mathbf{P}_{flow}^{\max} & \boldsymbol{\beta} \end{array}$$

where $\boldsymbol{\lambda}$, $\boldsymbol{\mu}^{\min}$, $\boldsymbol{\mu}^{\max}$, $\boldsymbol{\alpha}$ and $\boldsymbol{\beta}$ are the vectors of Lagrange multipliers associated with the corresponding equality and inequality constraints for the following Lagrangian function,

$$\begin{aligned} \mathcal{L} = \sum_{i=1}^{n}\Theta_{gi} - \boldsymbol{\lambda}^{\mathrm{T}}\left[\mathbf{P}_g^p + \mathbf{GD}\cdot\mathbf{e} - \mathbf{P}_d^p - \mathbf{GD}^T\cdot\mathbf{e} - \mathbf{P}(\boldsymbol{\delta})\right] \\ + \left(\boldsymbol{\mu}^{\min}\right)^T\cdot\mathbf{P}_g^p - \left(\boldsymbol{\mu}^{\max}\right)^T\left[\mathbf{P}_g^p + \mathbf{GD}\cdot\mathbf{e} - \mathbf{P}_g^{\max}\right] \\ - \boldsymbol{\alpha}^{\mathrm{T}}\left[-\mathbf{P}_{flow}^{\max} - \mathbf{P}_{flow}(\boldsymbol{\delta})\right] - \boldsymbol{\beta}^{\mathrm{T}}\left[\mathbf{P}_{flow}(\boldsymbol{\delta}) - \mathbf{P}_{flow}^{\max}\right] \end{aligned} \tag{A.6}$$

In this formulation, the optimization variables are $\mathbf{P}_g^p$ and $\boldsymbol{\delta}$, rather than $\mathbf{P}_g$ and $\boldsymbol{\delta}$ as used in the original formulation given by equation (3.8), however the two are completely equivalent. Note that for simplicity, in the problem formulation (A.5), the bus voltage magnitudes are assumed fixed at one per unit by sufficient VAr resources.

The partial derivatives of $\mathcal{L}$ with respect to the variables $\mathbf{P}_g^p$ and $\boldsymbol{\delta}$ yield two of the necessary conditions,

$$\frac{\partial \mathcal{L}}{\partial \mathbf{P}_g^p} = \mathbf{I\Theta} - \boldsymbol{\lambda} + \boldsymbol{\mu}^{\min} - \boldsymbol{\mu}^{\max} = \mathbf{0}, \tag{A.7}$$

and

$$\frac{\partial \mathcal{L}}{\partial \boldsymbol{\delta}} = \boldsymbol{\lambda}^T \frac{\partial P(\boldsymbol{\delta})}{\partial \boldsymbol{\delta}^{\mathrm{T}}} - (\boldsymbol{\alpha} - \boldsymbol{\beta})^T \frac{\partial P_{flow}(\boldsymbol{\delta})}{\partial \boldsymbol{\delta}^{\mathrm{T}}} = \mathbf{0}. \tag{A.8}$$

Assuming quadratic generation offers,

$$\Theta_{gi} = c_{oi} + a_i P_{gi} + \frac{1}{2} b_i P_{gi}^2, \tag{A.9}$$

a typical element i of the vector of incremental costs for constant bilateral contracts, $\mathbf{I\Theta}$, is defined as,

$$I\Theta_i = \frac{\partial \Theta_{gi}}{\partial P_{gi}^p} = a_i + b_i P_{gi}. \tag{A.10}$$

The incremental cost of transferring power bilaterally, is the sensitivity of the overall cost Θ_g with respect to an arbitrary contract, GD_{ij}, under the optimality conditions of the market clearing problem (A.5). To derive this sensitivity, first we reformulate the market clearing problem (A.5) in a more general form,

$$\min \quad C(\mathbf{x}, \boldsymbol{\pi}) \tag{A.11}$$

$$s.t \quad \mathbf{F}(\mathbf{x}, \boldsymbol{\pi}) \leq \mathbf{0},$$

where $\mathbf{x}$ is the vector of the problem decision variables, namely $\mathbf{P}_g^p$ and $\boldsymbol{\delta}$, while $\boldsymbol{\pi}$ represents the bilateral contract parameters, $\mathbf{GD}$. The term $C(\mathbf{x}, \boldsymbol{\pi})$ is the cost function, while $\mathbf{F}(\mathbf{x}, \boldsymbol{\pi})$ defines the set of equality and inequality constraints of (A.5). The necessary conditions are then reformulated as,

$$\frac{\partial C}{\partial \mathbf{x}} - \frac{\partial \mathbf{F}^T}{\partial \mathbf{x}} \cdot \boldsymbol{\lambda} = \mathbf{0}, \tag{A.12}$$

where $\boldsymbol{\lambda}$ is the vector of Lagrange multipliers associated with the constraints.

Now, if we allow the parameter vector to vary by a small increment, $d\boldsymbol{\pi}$ both the equality and inequality constraint functions and the cost function must also vary according to,

$$d\mathbf{F} = \left[\frac{\partial \mathbf{F}}{\partial \mathbf{x}}\right]^T d\mathbf{x} + \left[\frac{\partial \mathbf{F}}{\partial \boldsymbol{\pi}}\right]^T d\boldsymbol{\pi} = \mathbf{0}, \tag{A.13}$$

as well as,

$$dC = \frac{\partial C}{\partial \mathbf{x}^T} d\mathbf{x} + \frac{\partial C}{\partial \boldsymbol{\pi}^T} d\boldsymbol{\pi}, \tag{A.14}$$

so that the change in the cost function can be expressed solely in terms of the change in the parameters as,

$$dC = \frac{\partial C}{\partial \boldsymbol{\pi}^T} d\boldsymbol{\pi} - \boldsymbol{\lambda}^{\mathrm{T}} \cdot \frac{\partial \mathbf{F}}{\partial \boldsymbol{\pi}^{\mathrm{T}}} d\boldsymbol{\pi}, \tag{A.15}$$

that is,

$$\frac{dC}{d\boldsymbol{\pi}} = \frac{\partial C}{\partial \boldsymbol{\pi}} - \frac{\partial \mathbf{F}^T}{\partial \boldsymbol{\pi}} \cdot \boldsymbol{\lambda}. \tag{A.16}$$

Note that if an inequality constraint, $F_i(\mathbf{x}, \boldsymbol{\pi}) \leq 0$, is inactive then its Lagrange multiplier, λ_i, is zero. Alternatively, if the constraint is active, its multiplier is negative. This necessary condition allows us to represent the inequalities as pure equalities in (A.13) without loss of generality.

Consider now a change in one arbitrary specific parameter, $\pi = GD_{ij}$, and assume that the quadratic generation offers are defined by (A.9). This gives the following partial derivatives with respect to the parameter, holding the decision variables constant,

$$\frac{\partial \Theta_{gk}}{\partial GD_{ij}} = \begin{cases} a_i + b_i \cdot P_{gi} = I\Theta_i; & k = i \\ 0 & k \neq i \end{cases}, \tag{A.17}$$

so that,

$$\frac{\partial \Theta_g}{\partial GD_{ij}} = I\Theta_i \tag{A.18}$$

and, also,

$$\frac{\partial \mathbf{F}}{\partial GD_{ij}} = \begin{array}{cl} \left[\begin{array}{c} 0 \\ \vdots \\ 1 \\ \vdots \\ -1 \\ \vdots \\ 0 \\ 0 \\ \vdots \\ 0 \\ 0 \\ \vdots \\ 1 \\ \vdots \\ 0 \\ 0 \\ \vdots \\ 0 \\ 0 \\ \vdots \\ 0 \end{array}\right] & \begin{array}{l} \\ \\ \longleftarrow \text{corresponding to bus } i \\ \\ \longleftarrow \text{corresponding to bus } j \\ \\ \\ \\ \\ \\ \\ \\ \longleftarrow \text{corresponding to bus } i \\ \\ \\ \\ \\ \\ \\ \\ \\ \end{array} \end{array} \tag{A.19}$$

Then, from (A.16)-(A.19),

$$\frac{d\Theta_g}{dGD_{ij}} = \frac{\partial \Theta_g}{\partial GD_{ij}} - \frac{\partial \mathbf{F}^T}{\partial GD_{ij}} \cdot \begin{bmatrix} \boldsymbol{\lambda} \\ \boldsymbol{\mu}^b \\ \boldsymbol{\mu}^{\max} \\ \boldsymbol{\alpha} \\ \boldsymbol{\beta} \end{bmatrix} \tag{A.20}$$

$$= I\Theta_i + (\lambda_j - \lambda_i) - \mu_i^{\max}$$

Thus, the increment in the total generation cost, $d\Theta_g$, due to a change in the bilateral trade, dGD_{ij}, can be written as,

$$d\Theta_g = I\Theta_i \cdot dGD_{ij} + (\lambda_j - \lambda_i) \cdot dGD_{ij} - \mu_i^{\max} \cdot dGD_{ij} . \tag{A.21}$$

The question, now, is how to allocate this incremental cost among the three services being analyzed? First, since in the above result only one bilateral contract changes and the pool demand is constant, all cost components in (A.21) are attributed to services related to the bilateral contract.

The first term in (A.21) corresponds to the incremental cost of generator *i* due to the change in the amount traded, dGD_{ij}. This term covers the basic cost of generating the GD_{ij} megawatts of bilateral power excluding any necessary ancillary services. This amount is paid by load *j* and collected by generator *i*.

The second term, $(\lambda_j - \lambda_i)\, dGD_{ij}$, reflects the cost of supplying losses and congestion management due to the incremental power transfer, dGD_{ij}. This term is clearly allocated to the bilateral contract GD_{ij}[30].

The third term in (A.21), namely $-\mu_i^{\max} dGD_{ij}$ exists only when generator *i* operates at its maximum output. Normally, this term is equal to zero since generators often operate below their maximum limits. This cost reflects the fact that if generator *i* is operating at its maximum and one of its bilateral contracts changes, then its pool supply must also change, a change that, because of the nodal power balance requirement, affects the output of all other generators supplying pool power.

The way in which this third cost component is allocated however is not unique. One way to allocate the third term in (A.21), $-\mu_i^{\max} dGD_{ij}$, is to assume that it is the responsibility of the generator, and this is the choice made in this thesis. Note that $\mu_i^{\max}$ is negative, thus this term is an extra cost to the generator.

Under this assumption, the system incremental cost equation (A.21) can be split into two cost increments,

$$d\Theta_g = d\Theta_{gi}^{b} + d\tilde{\Theta}_{ij}^{bcl} . \tag{A.22}$$

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[30] Costs allocated to the bilateral contracts eventually have to be split among the bilateral parties as discussed in Chapter 3.

one for the basic bilateral contract generation,

$$d\Theta_{gi}^{b} \triangleq I\Theta_i \, dGD_{ij}, \tag{A.23}$$

and the other for the supply of the corresponding ancillary services,

$$d\tilde{\Theta}_{ij}^{bcl} = \left(\lambda_j - \lambda_i - \mu_i^{\max}\right) dGD_{ij}. \tag{A.24}$$

The ancillary service term can be further split into the sum of two terms, one accounting for losses and congestion management only,

$$d\Theta_{ij}^{bcl} = \left(\lambda_j - \lambda_i\right) dGD_{ij}. \tag{A.25}$$

and the second accounting for operation at maximum generation capacity,

$$d\Theta_{gi}^{\max} = -\mu_i^{\max} \, dGD_{ij}. \tag{A.26}$$

Under marginal pricing used in Chapters 4 and 5, equation (A.25) defines the power transfer rate, that is,

$$\pi_{ij}^{bcl} = (\lambda_j - \lambda_i) \tag{A.27}$$

as under this pricing mechanism the influence of generators that operate at the maximum output levels is implicitly accounted through nodal prices.

Appendix B

Mechanisms for Acquiring Firm Bilateral Status

Purchased Firm Bilateral Status (PFBS)

The systematic auction mechanism carried out by the SO to allocate PFBS to bilateral contracts is now presented. To compete for firm status, each bilateral contract submits a bid to the SO representing the value that the contract parties jointly place on acquiring firm status. This value should normally be less than the negotiated price of the bilateral agreement. The SO then allocates firm status as shown below to the sub-set of bidders who place the highest combined worth on their requested bilateral contracts. The contracts that are assigned firm rights by the auction pay to the SO an amount equal to the value that they quoted.

In this auction, the bid submitted by each bilateral contract specifies the points of injection, i, and consumption, j, and the price in \$/MWh that the contract parties are willing to pay, bf_{ij}^{app}, for the eventual amount of firm power allocated, $\widetilde{GDF}_{ij}$. This level of firm allocated power must be less than or equal to the amount desired, that is, $\widetilde{GDF}_{ij} \leq \widetilde{GDF}_{ij}^{des}$.

The auction run by the SO is settled by solving an optimization that maximizes the combined revenue from all bids, while respecting the system constraints,

$$\underset{\widetilde{\mathbf{GDF}}}{Max} \ \sum_{i,j=1}^{n} bf_{ij}^{app}\, \widetilde{GDF}_{ij} \tag{B.1}$$

$$\text{s.t.} \quad (\mathbf{P}_g, \mathbf{Q}_g, \mathbf{V}, \boldsymbol{\delta}) \in S$$

$$0 \le \widetilde{GDF}_{ij} \le \widetilde{GDF}_{ij}^{req}$$

$$\mathbf{P}_g \ge \mathbf{P}_g^b = \widetilde{\mathbf{GDF}} \cdot \mathbf{e}$$

The set S above denotes the same security region of the power system defined in Chapter 3 including the real and reactive bus power balance at every network bus. Note also that the pool demands are set to zero, as only bilateral trades are considered in this preliminary auction.

Thus, the auction for firm bilateral status is carried in a systematic fashion that accounts for both the network power balance at all buses and for transmission flow constraints. This is an important feature when compared to the allocation of financial transmission rights which in practice is based on simple transmission capacity models which may not accurately reflect the true transmission capacity.

The allocated firm contract amount, $\widetilde{GDF}_{ij}$, then becomes the pre-approved firm requested bilateral contract, GDF_{ij}^{app}, used in Chapter 5. Generally, if there is sufficient transmission capacity, the requested and the allocated or approved values will be the same.

As discussed before, once a firm contract is approved, the trading parties have both the right and the obligation to transfer the allocated amount of power. In addition, the trading partners acquire the right to be compensated for a price if this firm contract needs to be curtailed by the SO, as discussed in Chapter 5.

The revenue of the SO from the above auctions is,

$$R_{SO}^{app} = \sum_{i,j=1}^{n} bf_{ij}^{app}\, \widetilde{GDF}_{ij}\,, \tag{B.2}$$

which becomes part of the SO merchandising surplus.

First-Come-First-Serve Firm Bilateral Status (FFBS)

The allocation of firm bilateral status can also be acquired using a First-Come-First-Serve method. Here, the SO performs the allocation procedure periodically as new requests for bilateral firm status are received. Allocation of the remaining capacity is performed without modifying any of the firm bilateral contracts previously approved. Also, in a new batch, all requests for firm status have the same priority.

Since the objective of the SO is still to maximize the combined value of the approved firm bilateral contracts, the objective function as defined in (B.1) is used here with $bf_{ij}^{app} = 1$ for all new allocated bilateral agreements, $\widetilde{GDF}_{ij}$. Moreover, the lower generation limit now also has to account for the already approved bilateral contracts, GDF_{ij}^{app}, that is, $\mathbf{P}_g \geq \mathbf{P}_g^b = (\mathbf{GDF}^{app} + \widetilde{\mathbf{GDF}}) \cdot \mathbf{e}$. Thus, in the sequential First-Come-First-Served approach, the SO allocates firm bilateral status by carrying out the following optimization procedure,

$$\underset{\widetilde{\mathbf{GDF}}}{Max} \sum_{i,j=1}^{n} \widetilde{GDF}_{ij} \tag{B.3}$$

$$\text{s.t.} \quad (\mathbf{P}_g, \mathbf{Q}_g, \mathbf{V}, \boldsymbol{\delta}) \in S$$

$$0 \leq \widetilde{GDF}_{ij} \leq \widetilde{GDF}_{ij}^{des}$$

$$\mathbf{P}_g \geq \mathbf{P}_g^b = (\mathbf{GDF}^{app} + \widetilde{\mathbf{GDF}}) \cdot \mathbf{e}$$

As in the case of (B.1), the set S denotes the power system security region that includes the real and reactive bus power balance at each bus.

In the First-Come-First-Serve approach, as the bilateral parties do not pay to acquire firm status, the SO does not collect any revenue. A difficulty with this approach is that when there is not sufficient transmission capacity the solution of (B.3) may not be unique.

Appendix C

5-bus Network

A line diagram of the five-bus illustrative network used in these studies is given in Figure C-1, while Table C-1 shows the network line data. The line series impedances and shunt reactances are in per unit on a basis of 100 MVA and 200 kV. The column, $P_f^{\max}$, denotes the absolute line flow limits in MW.

From	*To*	*r* (p.u.)	*x* (p.u.)	*b* (p.u.)	$P_f^{\max}$ (MW)
1	2	0.0147	0.168	0.138	300
1	4	0.0108	0.126	0.102	355
2	3	0.0185	0.210	0.185	300
3	4	0.0294	0.336	0.296	300
3	5	0.0221	0.252	0.213	300
4	5	0.0108	0.126	0.104	450
2	4	0.0105	0.130	0.100	360

Table C-1. Network line data.

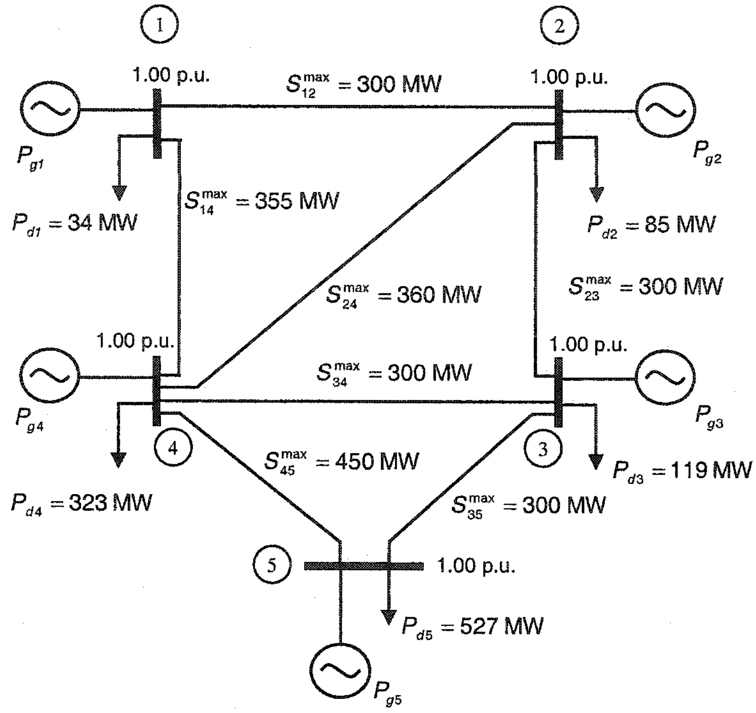

Figure C-1. Line diagram of 5-bus network

The cost data *offers* by the generators to supply power to the pool (to meet transmission losses, congestion, and pool demand) is given in Table C-2. Note that the unit commitment requires that all five generators be available.

Generator Bus	P_g^{max} (MW)	c_0 (\$/h)	***a*** (\$/MWh)	***b*** (\$/MW^{2}h)
1	500	400	20	0.040
2	500	500	21	0.030
3	500	600	25	0.045
4	500	400	56	0.040
5	500	400	57	0.040
$P_g^{min} = 0$ for all generators				

Table C-2. Generator bid data.

The inelastic system demand of 1088 MW is distributed among the buses according to:

$$\mathbf{P}_d = [34\ \ 85\ \ 119\ \ 323\ \ 527]^T \quad \text{MW}, \tag{C.1}$$

with the matrix of bilateral trades defined as

$$\mathbf{GD} = \rho \begin{bmatrix} 20 & 30 & 20 & 90 & 100 \\ 0 & 20 & 20 & 70 & 150 \\ 0 & 0 & 30 & 30 & 60 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \quad \text{MW}. \tag{C.2}$$

A proportion between a pool and bilateral demand is controlled through parameter $\rho \in [0,1]$. For $\rho = 0$ all of the demand is supplied though the pool, while $\rho = 1$ indicates that loads are buying only through bilateral contracts. The pool part of the demand, $\mathbf{P}_d^p$, is equal to the difference between the vectors of total bus demands and the bilateral bus demands,

$$\begin{aligned} \mathbf{P}_d^p = \ & \mathbf{P}_d \quad - \quad \mathbf{P}_d^b \\ = & \begin{bmatrix} 34 \\ 85 \\ 119 \\ 323 \\ 527 \end{bmatrix} - \rho \begin{bmatrix} 34 \\ 85 \\ 119 \\ 323 \\ 527 \end{bmatrix} \quad \text{MW}. \end{aligned} \tag{C.3}$$

Appendix D

24-Bus Network

The 24 bus network used here a slightly modified IEEE 24-bus network. Line data of this network are given in Table C-1, where the line series impedances and shunt reactances are in per unit while the column, P_f^{max}, denotes the absolute line flow limits in MW.

From	*To*	*r* (p.u.)	*x* (p.u.)	*b* (p.u.)	P_f^{max} (MW)
1	2	0.003	0.014	0.461	175
1	3	0.055	0.211	0.057	175
1	5	0.022	0.085	0.023	175
2	4	0.033	0.127	0.034	175
2	6	0.050	0.192	0.052	175
3	9	0.031	0.119	0.032	175
3	24	0.002	0.084	0	400
4	9	0.027	0.104	0.028	175
5	10	0.023	0.088	0.024	175

Table D-1. 24-bus network: Line data.

From	To	r (p.u.)	x (p.u.)	b (p.u.)	P_f^{max} (MW)
6	10	0.014	0.061	2.459	175
7	8	0.016	0.061	0.017	175
8	9	0.043	0.165	0.045	175
8	10	0.043	0.165	0.045	175
9	11	0.002	0.084	0	400
9	12	0.002	0.084	0	400
10	11	0.002	0.084	0	400
10	12	0.002	0.084	0	400
11	13	0.006	0.048	0.1	500
11	14	0.005	0.042	0.088	500
12	13	0.012	0.048	0.1	500
12	23	0.011	0.097	0.203	500
13	23	0.005	0.087	0.182	500
14	16	0.002	0.059	0.082	500
15	16	0.006	0.017	0.036	500
15	21	0.006	0.049	0.103	500
15	21	0.007	0.049	0.103	500
15	24	0.003	0.052	0.109	500
16	17	0.003	0.026	0.055	500
16	19	0.002	0.023	0.049	500
17	18	0.014	0.014	0.030	500
17	22	0.003	0.105	0.221	500
18	21	0.003	0.026	0.055	500
18	21	0.005	0.026	0.055	500
19	20	0.005	0.040	0.083	500
19	20	0.003	0.040	0.083	500
20	23	0.003	0.022	0.046	500
20	23	0.009	0.022	0.046	500
21	22	0.009	0.068	0.142	500

Table D-2. Line data (cont.)

The cost data *offers* by the generators to supply power to the pool is given in Table C-2. The inelastic total system demand is distributed among the buses as shown in Table D-3, and part of demand is supplied through bilateral contracts defined in Table D-4.

Generator Bus	$P_g^{\max}$ (MW)	c_0 (\$/h)	a (\$/MWh)	b (\$/MW²h)
1	192	0	28	0.02
2	192	0	28	0.02
7	300	0	27	0.03
13	591	0	30	0.01
15	410	0	20.5	0.08
16	350	0	15	0.02
18	400	0	17.5	0.01
21	400	0	17.5	0.01
22	300	0	19	0.005
23	660	0	14.5	0.01
$P_g^{\min} = 0$ for all generators				

Table D-2. Generator bid data.

Bus Number	$P_g^{\max}$ (MW)	***Bus Number***	$P_g^{\max}$ (MW)	***Bus Number***	$P_g^{\max}$ (MW)
1	108	9	175	17	0
2	97	10	195	18	333
3	180	11	0	19	181
4	74	12	0	20	128
5	71	13	265	21	0
6	136	14	194	22	0
7	125	15	317	23	0
8	171	16	100	24	0

Table D-3. Load data

Generator Bus	Generator Bus	GD (MW)
1	10	50
13	15	75
16	18	150
18	18	50
23	14	146

Table D-4. Bilateral contracts