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Service identification and allocation in market-based power system operation

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LIST OF SYMBOLS

Δ:	incremental / decremental value
$\mathcal{R}$:	revenue of market participants
$\mathcal{P}r$:	selling price
$\mathcal{C}s$:	cost of service
$\mathcal{C}e$:	cost of energy production
$\mathcal{C}_{adj}$:	cost of transaction adjustment
π:	profit
pr:	bid price submitted to the ISO
C:	cost
EC:	explicit cost
OC:	opportunity cost
MC:	marginal cost
$E\pi$:	expected profit
a, b, c, d:	coefficients
PUC:	per unit capacity cost
P, Q, S:	real, reactive and apparent power
SV:	level of service
V, δ:	voltage magnitude and angle
I:	current injection
Tap:	tap position
K:	swing bus distribution factor
AS:	average sensitivity

nt, ns:	number of transactions and service providers
G, B:	line conductance and susceptance
$prob$:	probability
F, f:	general function
X:	general variable
IV:	capital cost investment
af:	availability factor
lf:	load factor
pf:	power factor

subscripts:

t:	index of energy market participant and transaction
m, k:	index of services
b:	buyer
s:	seller
sv:	service provider
p:	real power
q:	reactive power
s:	apparent power
i, j:	bus index
g:	generator
d:	load
c:	capacitor
x:	transformer
l:	loss
max, mx:	maximum value
min, mn:	minimum value
x, y:	transactions

superscripts:

ebuyer:	energy buyer
eseller:	energy seller
etran:	energy transaction
sprovider:	service provider
erg:	energy market or energy market participants
loss:	loss market or loss market participants
p:	proposed transaction or service
a:	transaction adjustment
s:	scheduled real and reactive power

1 INTRODUCTION

The increased competition, change in government regulation and customers' ability for choice have provided the electric industry in the US a more competitive environment. The importance of ancillary services and other interconnected services cannot be overemphasized in maintaining system security and reliability in this new climate.

Among the several re-regulation models that have evolved so far, a central entity, called the independent system operator (ISO), has been created to have various responsibilities including identifying the necessary services and allocating the costs of services to the transmission users.

In the research reported in this dissertation, how the ISO should identify and allocate the services of reactive support and real power loss are the major focus. Preliminary service identification and allocation for reactive support as a part of this research were reported in [1, 2] and [3].

In this section, the motivation and objective of this research is first presented. After that, the background that is the basis of this work is described. The problem statement is provided in the following section, followed by an overview of the original contributions. The last part of this chapter is an executive summary.

1.1 Research Motivation and Objective

This research was motivated by the challenges that the electric industry faces in a competitive environment, in identifying and allocating the ancillary services and other interconnected services. These services, according to the definitions in the Federal Energy Regulatory Commission's (FERC) Notice of Proposed Rulemaking [4], are "those necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas

and transmitting utilities within those control areas to maintain RELIABLE operation of the inter-connected transmission system."

The services listed in FERC's order 888 [5] include:

- Ancillary services
  - Scheduling, system control and dispatch service;
  - Reactive supply and voltage control from generation source service[1];
  - Regulatory and frequency response service;
  - Energy imbalance service;
  - Operating reserve — spinning reserve service; and
  - Operating reserve — supplemental reserve service.
- Other interconnected services
  - real power loss service
  - dynamic scheduling service
  - backup supply service
  - restoration service

Until a few years ago, these services were bundled together and were provided by the vertically integrated utilities, who were nearly the only participants. The changes that have occurred include increased competition with additional new players; and modified regulations for the U.S. electricity industry. As the costs related to these services are approximately $14 billion per year in US [6], it has been realized that unbundling these services is likely to promote economic efficiency in terms of increased competition among the service providers and lowered cost to customers. The problem of service identification and allocation becomes a key factor in the overall structure of deregulation.

[1] In this research, this service is called reactive support service for short.

However, identifying individual services as a separate commodity is complicated by the level of transactions, various market conditions, the technical interdependences and the reliability requirements. Moreover, the non-linearity in the transmission grid as a whole and the simultaneity of transactions increase the complexity of service allocation.

Motivated by these challenges, the objectives of this research are to:

1. Define an optimization framework for the ISO to identify necessary services while managing transmission congestion; apply this framework into the service identification of reactive support and real power losses.

2. Develop an allocation algorithm for the ISO's use to allocate the cost of the identified services fairly and quickly .

1.2 Research Background — Power system Operation in the Competitive Environment

This research is based on a market-based competitive operational environment. Figure 1.1 describes the operation model. This model was developed by the author and is believed to be flexible enough to represent most situations. The roles of the markets, the databases, and the ISO are described in the following sections. A similar model is being implemented in the California utlitity restructuring.

1.2.1 Markets, Market Participants and Market Models

The roles of profit-driven entities are depicted in the top part of Figure 1.1. These entities include the transmission system owners and various market participants.

The transmission component of power delivery has declining average costs. It presently appears that transmission will remain a natural monopoly for the near future. Therefore, the transmission owners have few competitors and they profit from the current pricing structure.

The energy and service markets are the two market places, where the sellers compete for

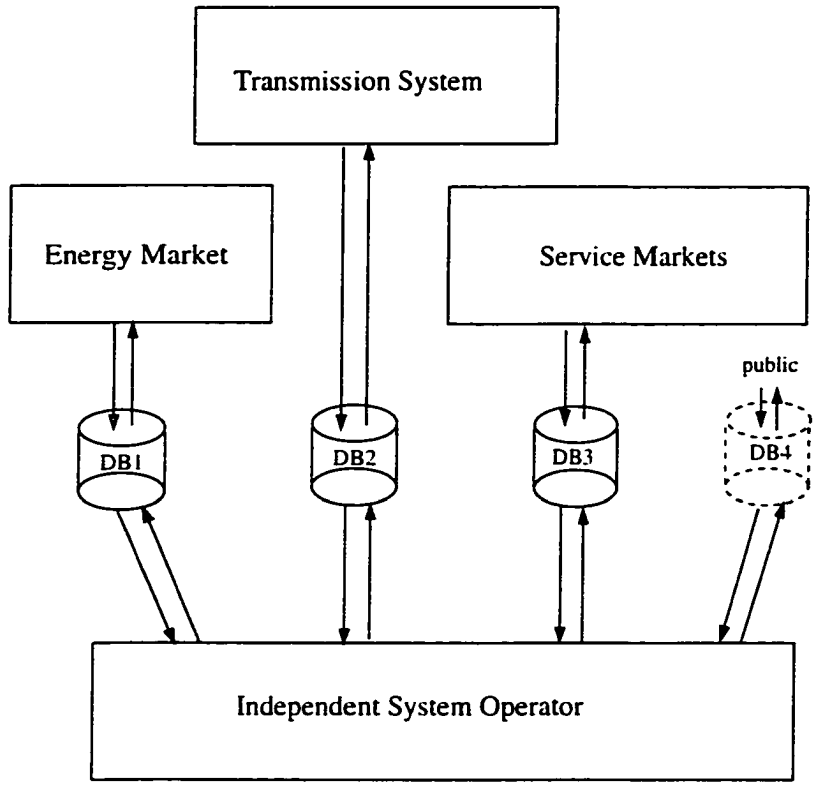


Figure 1.1 Power system operation model

demands and the buyers compete for supplies. [2] In California, these markets are called power exchanges and are operated by a group of schedule coordinators.

In the competitive environment, electric energy and the various related services are traded as commoditities. The individual decisions of commoditity production and consumption are aggregated and equilibrium prices result. Therefore, the market participants are not limited to the vertically integrated utilities, who historically were the main supplier of electricity before deregulation. Various players and their roles in the markets are listed in Table 1.1.

In both the energy market and the service markets, the commodities could be traded either through formal organized exchanges with well-defined rules and trading procedures, or through less-formal markets called over-the-counter markets.

Trading through organized exchanges is always via an auction system, of which there are a number of variants; but the general result is intense competition in the trading on both the

[2] Unless rules are in place, market conditions may, under certain conditions, produce a buyer or a seller market.

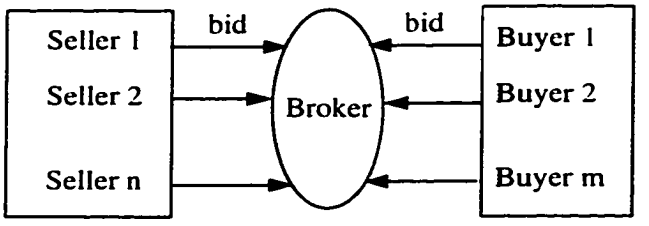
Table 1.1 The roles of market participants

Participants	Energy Markets	Service Markets
1. Gencos		
IOUs	seller/buyer	seller/buyer
Fed Gens	seller/buyer	seller/buyer
State Gens	seller/buyer	seller/buyer
G&T Co-ops	seller/buyer	seller/buyer
Munis	seller/buyer	seller/buyer
IPPs	seller/buyer	seller/buyer
Cogens	seller/buyer	seller/buyer
Other *NUGs*[a]	seller/buyer	seller/buyer
2. Transcos		
IOUs		seller
Fed Trans		seller
State Trans		seller
G&T Co-ops		seller
Munis		seller
Other NUTs		seller
3. Discos		
IOUs	buyer	seller/buyer
Dist Co-ops	buyer	seller/buyer
Munis	buyer	seller/buyer
4. Customers		
Industrial	buyer	buyer
Commercial	buyer	buyer
Residental	buyer	buyer
Agricultural	buyer	buyer
Other	buyer	buyer
5. Other Groups		
Power Marketers	seller/buyer	seller/buyer
Load Aggregators	buyer	buyer
Metering Service Co.		seller

a Certain member of the customer group may also function as NUGs in both the energy and service markets.

buying and selling sides [7]. The aution models that are involved in this research are the double auction and the single auction models.

A double auction model is depicted by Figure 1.2, where both the sellers and the buyers submit bids and the broker matches these bids according to the merit order. A clearing price is determined when there is little, if any, price difference between the seller's and the buyer's bid.



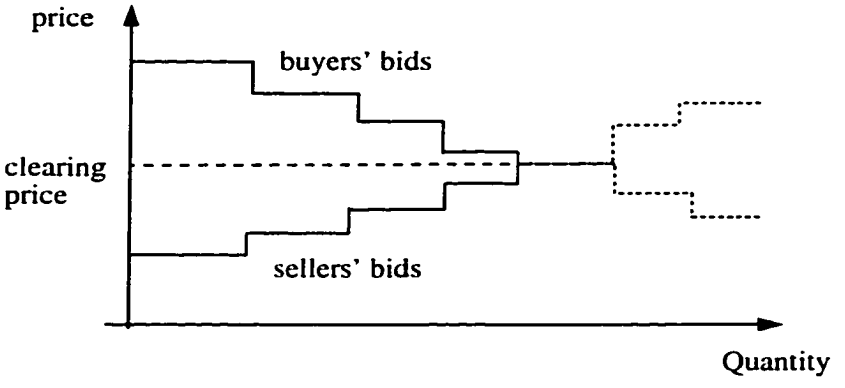


Figure 1.2 Double auction model

A single auction model is shown in Figure 1.3, where only sellers explicitly compete for customers. The clearing price will be determined by the last bid price when the forecast demand is met.

The over-the-counter markets are usually the dealer markets, which are described by Figure 1.4. A broker or dealer makes a market by offering to both buy and sell an asset. Sometimes, the buyer and the seller contact each other directly and make a deal. This model is also called the bilateral contract model.

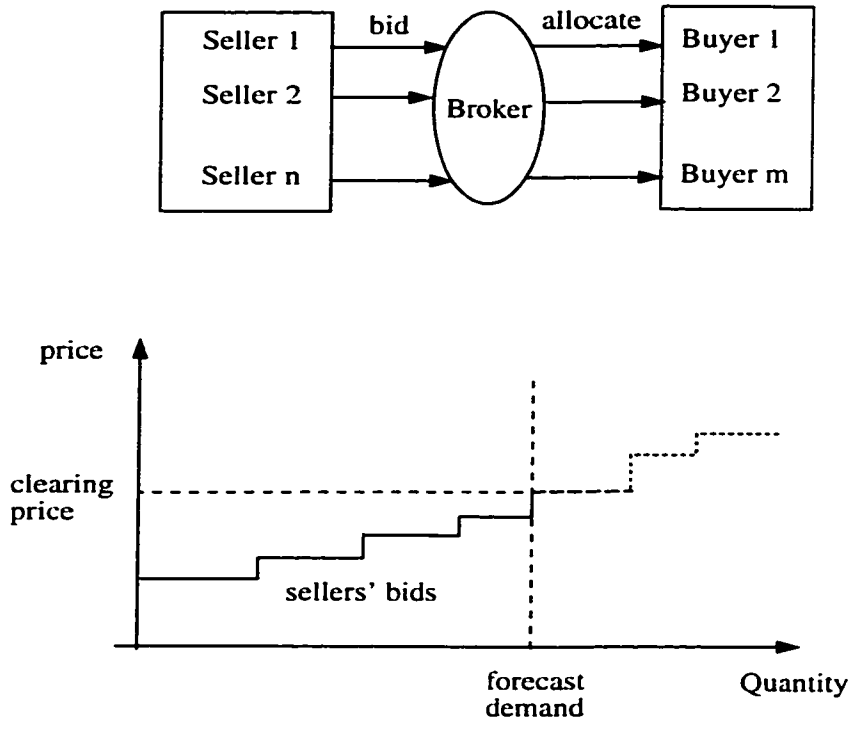


Figure 1.3 Single auction model

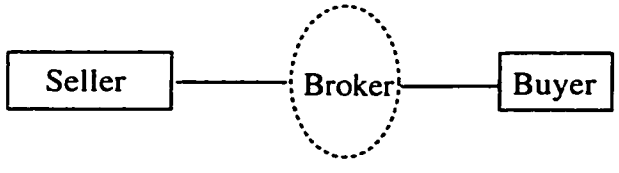


Figure 1.4 Over-the-counter (bilateral contract) model

Different market models have been adopted by different countries and U.S. states in their re-regulation process. In UK, a single auction model is being implemented, where the system operator determines the seller's bids and energy price so that the forecasted loads can be satisfied. California allows both the double auction and over-the-counter models for their energy markets.

For the service markets, different services are unbundled and are traded seperately. A market clearing price for each service will be calculated. In addition to the double auction and bilateral contract model that could be used, a single auction model is required for ISO to select necessary services for system reliability.

Figure 1.1 is flexible enough to include each of the market models just described. For reasonable analysis in this research, the energy market was assumed to include both the double auction and over-the-counter models. For the service markets, the two markets that were considered are the reactive support market and real power loss market. They are each assumed to be a single auction market. Table 1.2 lists the market models that were used in this research.

Table 1.2 The market models used in this research

	Double auction	Single auction	Over-the-counter
Energy markets	√		√
Reactive support market		√	
Real power loss market		√	

1.2.2 Databases

As shown in Figure 1.1, several databases were used to store the necessary information related to the energy markets, the service markets, the transmission system and the ISO. The first database, DB1, is a confidential energy market database, which contains the information for proposed and accepted transactions bids. DB2 is a confidential database for the individual transmission systems. Any confidential information, such as the cost of transmission facilities and their operations, is stored here. DB3 is a confidential service market database and it contains the information for the proposed and accepted service bids. The last database, DB4, is a public database for maintaining information such as historical generation and transmission

data, transmission maintenance schedules, transmission rates[3], available transmission capacity (ATC), and etc. It has the same function as the open-access same-time information service (OASIS).

Since this research is modeling only a subset of the ISO's functions, it only requires a portion of the information in these databases. The related information flow is listed in Table 1.3.

1.2.3 The Independent System Operator

A central coordinator, defined as the independent system operator (ISO), plays an important role in guaranteeing transmission open access on a non-discriminatory basis.

In Reference [5], eleven ISO principles are provided which include:

1. The ISO has a fair, non-discriminatory governance structure.
2. The ISO has no financial interests in any power market participants.
3. There is a single, open-access tarriff for the entire ISO area.
4. The ISO has responsibility for system security.
5. The ISO may control system dispatch in its area for effectuating pool or bilateral dispatches.
6. The ISO can identify and resolve transmission constraints.
7. The ISO has incentives to act efficiently.
8. The ISO's transmission and ancillary service pricing promotes efficiency.
9. The ISO must post transmission availability in real time on electronic bulletin boards.
10. The ISO must coordinate with adjacent control access.
11. The ISO must have a dispute resolution procedure.

[3]Practically, different transmission rate may exist within the ISO's control area.

Table 1.3 Information flow related to the research

	In-bound information flow to ISO	Out-bound information flow from ISO
DB1 (confidential)	**proposed transactions** for each transaction. 1. Buyer and seller names 2. Energy amount 3. Buying and selling price 4. Buying and selling adjustment bid 5. Buying and selling locations 6. Beginning and ending time	**accepted transactions** for each transaction. 1. Accepted energy amount 2. Expected cost of losses 3. Expected cost of reactive support
DB2 (confidential)	1. Cost data for transformer 2. Cost data for capacitors	1. Tap positions 2. Capacitor switching schedule
DB3 (confidential)	**proposed reactive support service** for each bid. 1. Seller names 2. Price of reactive power 3. Location of reactive power 4. Min-max reactive power range 5. Beginning and ending time **proposed real power loss service** for each bid. 1. Seller names 2. Price of loss support 3. Location of loss supporter 4. Min-Max loss support range 5. Beginning and ending time	**accepted reactive support service** for each bid. 1. Voltage setting 2. Reactive power output 3. Expected service payment **accepted real power loss service** for each bid. 1. Amount of real power output 2. Expected service payment
DB4 (public)	1. Transmission facility technical data 2. Generation facility technical data 3. Loading /voltage limits 4. Availability of facilities 5. Typical power flow data and current schedules 6. Typical market price data and transmission rates	1. Forecasted power flow 2. Forecasted price of service

Membership and departure requirements must also be defined and be public knowledge. According to these principles, different ISOs may develop their own functions based on the requirement specified by their regulation rules.

In this research, the ISO's technical functions are of major concern. Based on the market-based power system operation model set up by the author, the ISO's technical functions are divided into three parts as shown in Figure 1.5.

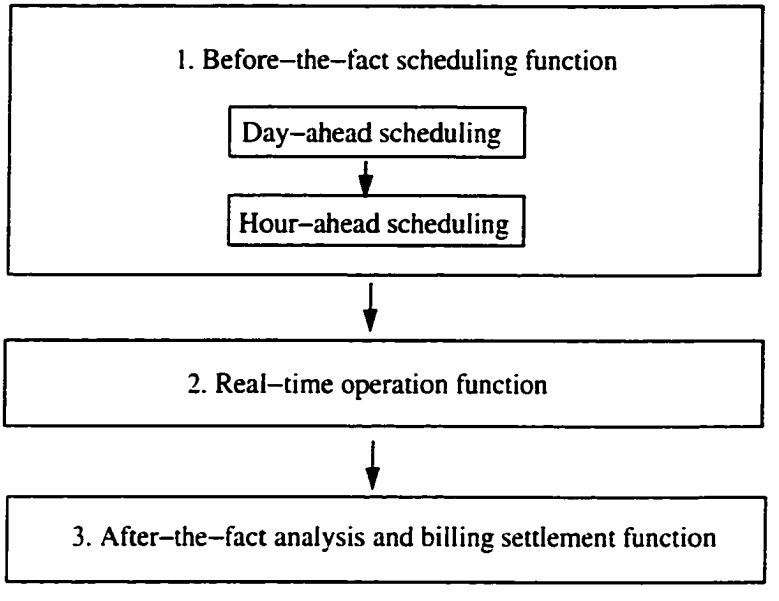


Figure 1.5 ISO functionalities

- Before-the-fact scheduling

  The scheduling process has been designed to provide reasonable time frames so that the ISO can do periodic analysis to ensure reliable transmission system operation, and the market participants can make realistic operational decisions.

  This process is divided into two time frames [8]: the day ahead energy schedule, to be completed approximately 5-10 hours before the beginning of the operating day, and hour-ahead energy schedule, which occurs approximately one hour prior to each hour within the operating day.

- Day-ahead scheduling

  The day-ahead schedule is developed after several iterations between market participants and the ISO. The ISO uses computer tools to evaluate whether all energy schedules can be accommodated simultaneously on the transmission system. These schedules come from the successfully matched bids by the brokers and the two parties of bilateral contracts. If the ISO finds potential transmission congestion, it informs the scheduling parties how, based on modeling results, the congestion will be eliminated.

  Market participants could modify and resubmit their schedules. It further requires the brokers to re-match the modified bids. The ISO will then resolve any remaining congestion by the same process until no congestion would occur or the time for day-ahead scheduling is over.

  The day-ahead scheduling also includes the scheduling of services. Parties wishing to offer services will submit bids. Based on the day-ahead energy schedules submitted, the ISO will determine what services it needs to support the resultant scheduled transactions. The ISO will also allocate the expected cost of services to each energy market participant. This allocated cost information will assist them in making operational decisions and adjusting bids. To the service providers, the ISO acts as a buyer, and to the transmission users, the ISO acts like a service seller.

- Hour-ahead scheduling

  The day-ahead accepted schedules become the basis for settlement in the real-time market. Parties will however, be able to ask the ISO for schedule adjustments closer to real time. The goal is to move the time at which the last schedule adjustments can be accepted by the ISO to as close as possible to real time. This will permit suppliers to most closely commit to meeting the requirments of their customers. In contrast to day-ahead scheduling process, there will be no iteration between the ISO and the market participants in response to congestion.

- Real time operation

  The ISO is responsible for the second-to-second balancing of system-wide generation and load to meet the control area operating criteria. It will use the services that it has acquired. If a system emergency occurs, the ISO has the authority to order on or off any generator or load and adjust any schedules to maintain or restore reliable, stable system conditions. It will also record the actual system operation as it occurs on a second-to-second basis.

- After-the-fact analysis and billing settlement

  No matter how well the participants do their forecasting, the actual load, generation, and transmission system conditions will differ from what was scheduled. The ISO will use the recorded results of real-time operation to determine the final cost to each participant that reflects actual usage.

1.3 Problem Statement

This research is focused on the challenges that are faced by the ISO in the day-ahead scheduling function. Three functional activities are considered including : congestion management/transaction adjustment, service identification, and service allocaiton. The relationship between the three functions is shown in Figure 1.6.

In this section, the assumptions that this research is based upon are discussed in Secion 1.3.1. The problem descriptions for the three functions are provided in Sections 1.3.2.

1.3.1 General Assumptions

1. Assumptions on the market models

   (a) Imperfect competition exists in the energy markets and services markets.

   In a perfectly competitive market, there are no barriers to entry and exit. No single participant has the power to influence the prices and the marginal cost of production equals to the market price. However, in the actual energy markets and

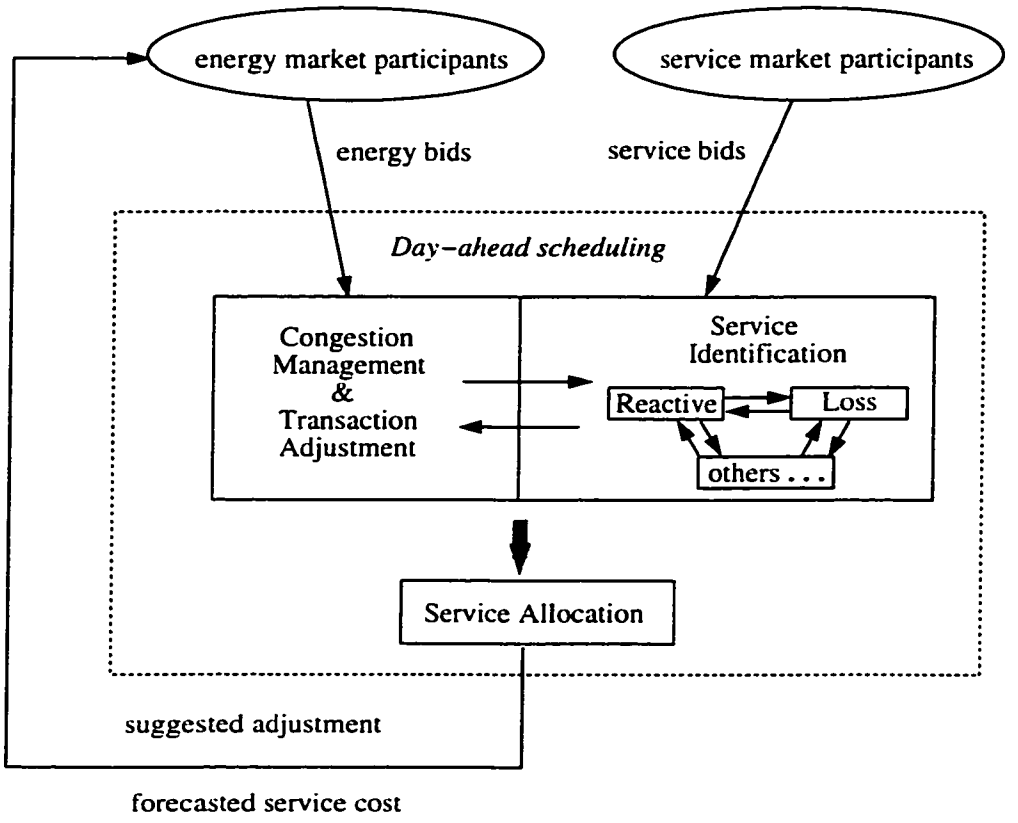


Figure 1.6 Three function modules in day-ahead scheduling

service markets that have come in to existence so far and appear to evolve in the near future. some barriers to entry and exit exist, as listed in Reference [9]. In addition, some participants may be able to influence prices if sufficient competition does not exist.

(b) The energy market was assumed to include the double auction and over-the-counter (bilateral contract) models. Service markets were assumed to be based on the single auction model.

All the three models are allowed in the energy market and the service markets. But at least the single auction markets must be in existence for the ISO to guarantee sufficient services for system security. The assumptions for the market models are only for the research convenience and will not affect the general results and conclusions.

(c) The transmission and distribution systems were assumed to be monopolies. Retail access was not allowed.

It is widely accepted that the transmission stage of the power industry has declining average costs over the range of outputs observed today [10]. It appears that transmission will remain a natural monopoly for the near future. Most observers also believe that the distribution stage of the industry is a natrual manopoly, although agreement is not universal.

The prerequisite for direct retail access is a well-functioning wholesale market, an open-access transmission system, an independent system operator, well-defined ancillary services, etc. These prerequisites are still developing. It was assumed that no retail access is allowed. The distribution system will take full responsibility to serve the customers. However, it is realized that retail markets are being established and more will occur in the future. This assumption does not violate the operation models, but it does service to simplify the research compliexity.

2. Assumptions on the market participants

(a) Rational behavior of market participants were assumed.

The rational behavior of the individual participants is to maximize the individual utility. It is assumed that this utility is proportional to the individual economic profit.

(b) Capital cost investment is recovered hourly.

This research deals with the day-ahead scheduling of the ISO, which is, by its definition, a short run behavior. Generally, the decision making in the short run does not require the inclusion of fixed cost. However, power system devices require large investments of capital cost. Traditionally these costs are covered by the customers through the prices they pay. In the competitive environment, these costs could be transformed into the cost per operating hour per MW, MVar or MVA. Whenever the devices are in operation, their related capital costs could be partly recovered.

3. Assumptions on the ISO's decision making

(a) There exists a known feasible base case and final case.

The base case is asssumed to be given. It includes previously agreed upon contracts that existed before the submission of proposed transactions. The ISO should have already identified an optimal amount and sources of services for these contracts to maintain system reliability. All the proposed energy transactions and service bids are assumed to be in addition to the base case. A feasible final case is assumed to exist. Otherwise, it is meaningless to attempt the real-time operation.

(b) Two-party energy transactions were the minimum unit for adjustment and allocation.

FERC and most utilities today function in a bilateral world [10], the bilateral contracts are called transactions. Although sometimes, one contract may involve several buyers and sellers, the multi-party contract can be decomposed into several two party transactions, that have the same effect as the orignal multi-party contract. However, the bilateral model (over-the-counter model) is not the only market model that is allowed in this research. In the double auction model, the matched selling

and buying bids can also be regarded as transactions between the sellers and buyers. When transaction adjustment is necessary, the adjustment is considered "intra-transaction" adjustment, i.e., the buyer and the seller for one transaction will be adjusted by the same amount.

The ISO will also allocate the cost of services based on transactions. But who will pay for them, the buyer, the seller, or both, is not the concern of this research. This research serves only to identify how to allocate the cost and service to individual transactions; the split within a transaction is a legal, rather than a technical question.

(c) A transaction was described by the real power that it is to be transferred. A fixed power factor was assumed if the buyer is a load.

(d) A steady state model of electric system is assumed.

The compelete description of power system involves the solution of algebraic equations and differential equations. In this research, the dynamic behavior of power system is considered beyond the scope of this research. Only the algebraic equations of the power system analysis were used.

(e) The level of services was assumed to be a continuous scalar function and was not affected by the transaction simulation order for simultaneous transactions.

For the services related to this research, i.e. the services of reactive support and real power losses, the service levels are continuous scalar functions with respect to transaction amount. Therefore, they will not be affected by the transaction simulation order.

1.3.2 Problem Description

1.3.2.1 Congestion Management and Service Identification

More and more transactions are utilizing the transmission system in the market-based operation environment. However, the capacity of the system is limited by physical constraints and

reliability requirement. In day-ahead scheduling, when the ISO finds out that the transmission system can not accommodate all the proposed transactions without violating reliability requirement, an optimal transaction curtailment should be determined through congestion management techniques.

Service identification is to identify the optimal amount and location of services, such as reactive support and real power loss services, so that the transmission system can accomodate as many transactions as possible. Since it was assumed that an optimal base case exists, the services identified were the additional services required by the additional transactions.

Congestion management and service identification are dependent on each other. The proposed transactions will determine how much of each service is required and the service level may aggrevate or alleviate the operating limits. Therefore, both the congestion management and the service identification will be affected by the transmission-related factors and market-related factors. These factors are listed in Table 1.4.

Table 1.4 Transmission-related factors and market-related factors

Factor		Congestion management	Service identification
Transmission-related			
System conditions	thermal overload	Within scope	Within scope
	voltage/Var conditions	Within scope	Within scope
	stability conditions	Outside scope	Outside scope
Cost of basic transmisison services		Outside scope	Outside scope
Network outage risk		Outside scope	Outside scope
Other		Outside scope	Outside scope
Market-related			
Intra-market	distribution of prices	Within scope	Within scope
	cost and bidding price	Within scope	Within scope
	buyer and seller location	Within scope	Within scope
	others	Outside scope	Outside scope
Inter-market	multiple market participation	Within scope	Within scope
	technical interdependence	Within scope	Within scope

Transmission-related factors

System conditions are important factors in congestion management and the resultant service identification. Congestion is a consequence of network constraints characterizing a finite network capacity that precludes the simultaneous delivery of the total power for an associated set of power transactions. The network constraints include thermal limits, voltage/VAR requirements and stability consideration. Since a steady state power system model was assumed in this research, only the thermal limit and voltage/VAR requirements were considered.

The *cost of basic transmission services* was determined by the transmission owner, since the transmission system is assumed to be a monoploy and their owners profits from the regulated transmission prices. It should be remembered that, according to FERC's rules, the transmission must charge the same price to all users including himself. Certainly, the market participants will be affected by the cost of transmission service according to the schedules determined by the ISO. However, this is outside the scope of this research.

Network outage risk is an aspect that affects system operation. The ISO should consider the probability and the impact of contingencies before making the operating decisions. However, how to incorporate this item into congestion management and service identification is outside the research scope.

Market-related factors

Intra-market factors include the distribution of bidding prices, cost and bidding prices of individual market participants, the buyer and seller's locations, and other attributes of the transactions. All these factors should be considered when competing the resources inside each service market and the energy market.

Inter-market factors include multiple market participations and the technical interdependence between various markets. One participant is able to participate in more than one market, as long as his utlitity function or economic profit is maximized. This will certainly affect the individual's decisions and the resultant ISO's decisions. The technical interdependence refers to

the coupling between energy and various services. For example, the acutal transaction amount affects the services required, such as the reserve and reactive support; and the appropriate level of services may alleviate transmission congestions.

Considering the transmission-related and market-related factors, an optimization procedure is proposed in this research to manage congestions and identify necessary services. Its objective is to maximize the overall profit of all market participants. In case of limited information, a lower bound profit maximization (cost minimization) becomes a substitute. How to evaluate the cost of services and prepare the bids are also presented as a part of this work.

1.3.2.2 Service Allocation

Service allocation is to divide the amount and cost of services among the individual transactions. However, the further division within the transaction, if any, between the seller and the buyer is not of interest.

As the transactions are added simultaneously on the transmission system, the non-linearity of the system increases the difficulty of service allocation. For a successful allocation algorithm to work, it must include the following properties:

- Allocation quantity: the allocation quantity must fully recover the cost of services.
- Allocation ratio: the allocation ratio should reflect fairness, i.e. allocation should be based on the actual usage of the services by the individual transmission users.
- Application feasibility: the allocation method should be feasible in practical application, i.e. there should be no convergence problems and the method should require only limited computational time, capability, and storage.

It is almost impossible to find an algorithm that could easily satisfy all these properties. The average sensitivity method proposed in this work is a positive step toward this goal. Details of this method are presented in Chapter 6.

1.4 Overview of Original Contibutions

This section provides an overview of the original contributions made by this research. In this dissertation, an attempt has been made to clarify which parts of the work presented are the results of the assumptions and lessons drawn from existing literature, and which parts are the results of original work; this section clearly states the original contributions.

1. A possible representation of the structure for the combined energy market, service markets, the ISO and the market participants was defined. It can be used to analyze the behavior of market participants and the ISO.

2. A framework of total profit maximization was proposed in this research to identify services and manage congestion. Since the rational behavior of profit maximization for each participants is assumed, the ISO's decision will inevitably affect the individual's profit. By analyzing the cash flow among the market participants and the ISO, a total profit maximization was proposed so that the profit for each individual is treated equally in terms of dollar values.

3. The ideal optimization requires the accurate information on the cost of energy and services. However, these information is generally not directly available to the ISO. Given the available information, the lower bound profit maximization or upper bound cost minimization was proposed as a subsititute.

4. Because of the technical interdependence among the reactive power, transmission losses and congestions, identifying separately each service and the adjustment of transactions may under or overestimate the amount of services required. The lower bound profit maximization was applied in this research to simultaneously identify transaction curtailment, reactive support services and real power loss services.

5. The concept of economic cost has been widely used in economic analysis. It represents the true cost so that the economic profit can be evaluated as it affects the behavior of producers. In this research, the analytic framework of economic cost analysis was

presented. It is composed of the explicit and opportunity costs. Because of the various markets in which a producer can be involved, the opportunity cost reflects the intermarket related factors.

6. The opportunity cost for the reactive support service and real power loss service were identified and evaluated. The opportunity cost refers to the profit of capacity that is unrealizable because of the service production. Strategic bidding technique was applied to evaluate this profit.

7. The average sensitivity method is a significant improvement from the previously used power flow-based and sensitivity-based approaches. Theoretical evidence indicates that for a second-order service function, this method guarantees full cost recovery. For higher order service functions, the allocation quantity mismatch can be reduced and eliminated by piecewise approximations. These transaction sensitivities correctly reflect the usage of the services.

8. The average sensitivity method was applied to allocate the services of reactive support and real power loss. Practical implementation does not require complicated mathematical calculations. Under most operating conditions, the average loss sensitivity and average reactive power sensitivity require only limited number of power flows. Since the allocation is performed after the optimal service is identified, the allocation amount will not affect ISO's decisions.

1.5 Executive Summary

In Chapter 2, a review of the relevant literature is presented. Because of the wide scope of the services involved, this chapter is not intended to be a comprehensive bibliography on the issues that affect congestion management, service identification and allocation. However, an attempt has been made to provide a review of representative papers from each relevant area.

In Chapter 3, a framework of total profit maximization is presented and discussed. It is a combined method that simultaneously identifies services and determines transaction curtail-

ment.

In Chapter 4, a framework of economic cost analysis is presented. The economic cost is composed of the explicit opportunity costs. They are used to evaulate the cost of reactive support services and real power loss services. The evaluation method, especially the evaluation of opportunity cost is discussed in detail. The bid preparation is also briefly included in this chapter.

In Chapter 5, the proposed optimization approach is applied to determine curtailment and identify reactive support and real power loss services. Solution algorithms are also discussed.

In Chapter 6, a service allocation method using the average sensitivity method is presented. It begins with the theoretical proof of the average sensitivities, followed by a practical application that avoids complicated computations.

In first part of Chapter 7, test results of the economic cost analysis are presented. Results on service identification and congestion management are presented next. In the last part, the service allocation results are compared with other allocation mechanisms.

In Chapter 8, conclusions and suggestions for future work are presented and discussed.

2 REVIEW OF RELEVANT LITERATURE

2.1 Power Industry Restructuring

There are many issues associated with the power industry restructuring, especially when open access is fully considered. It is not possible to include all the related literature in this review. However, an attempt has been made in this section to review the papers that are most relevant. For a comprehensive bibliography of work related to these issues, see references [12] and [13].

2.1.1 Important Rules and Regulation Models

The power industry restructuring is being driven by the increased competition, changing regulation and increased customer choice. From the rules that have already been made, how US utility re-regulation has evolved thus far clearly can been seen.

As early as 1978, the passage of the Public Utilities Regulatory Policies Act (PURPA) first required utilities to purchase electricity at their avoided cost from qualifying facilities. The Energy Policy Act of 1992 further expanded wholesale competition. It opened all utilities to the unregulated generation business, and introduced wholesale wheeling between generators and distributors. This act laid the groundwork for the FERC "MegaNOPR" rulemaking [4], which proposed open access for the transmission under FERC's jurisdiction. In 1996, the passage of FERC's Order 888 [5] formally created open access. It required utilities to file nondiscriminatory open access tariffs and provided for recovery of stranded costs. State utility regulators have also enacted significant reforms — most prominently, California's ongoing restructuring and more recent proposals in almost every other state. It is interesting to note that three months after all customers in California were given the opportunity to select their

electricity provider, less than 0.5% have switched providers.

Several reform models have been implemented or are under discussion. In [14], these models can be classified into (1) franchise bidding, (2) competitive bidding for generation, (3) wholesale or retail wheeling, and (4) mandatory or voluntary pooling. The authors of [15] chose four models that correspond to varying degrees of monopoly, competition and choice in the industry. These models are: (1)monopoly at all levels, (2) purchasing agency or poolco, (3) wholesale competition, and (4) retail competition. Figure 2.1 shows how these models move closer to providing the consumer a choice of suppliers.

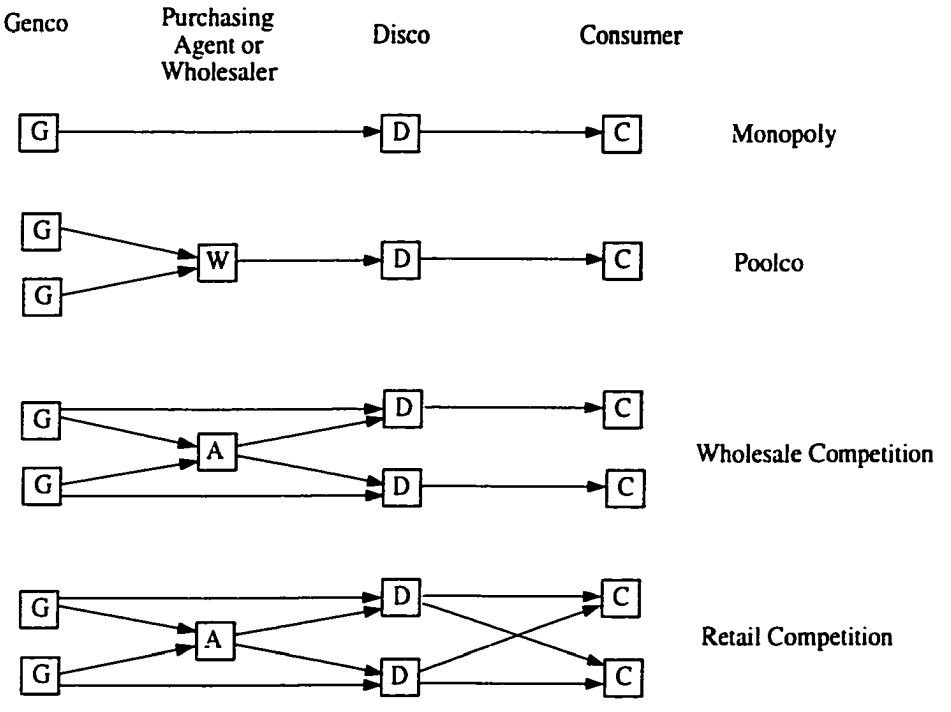


Figure 2.1 Regulation models

2.1.2 Energy Markets

In Reference [16], electric energy is viewed as a commodity. Although unlike other commodities, the energy can not be stored. It still can be traded in commodity markets. These markets include cash (spot) markets, futures markets, options markets, swap markets and planning markets. Energy brokers match the "bid" and "ask" prices in each market.

Several methods have been proposed for implementing a brokerage. A linear programming based implementation was proposed in [17], in which the optimal bids were selected by a LP-based bid-matching algorithm. Optimal bids can also be determined by the OPF method presented in [18].

Different market participants may use different strategies in determining their own energy bids. Strategic bidding, which is commonly used in other industries, has been introduced in the power area. In [19], a suboptimal bidding strategy was proposed, which resulted in the maximization of the expected lower bound profit on the savings achieved by a buyer or a seller. A novel approach by using genetic algorithms was presented in [20].

2.1.3 Independent System Operator

The creation of an "independent system operator" (ISO) is an idea that has gained almost universal acceptance in the restructuring debate. But the functions of the ISO vary from location to location. This can be reflected by the proposed names for the grid operator, which include the ISO, the independent grid operator (IGO), the independent tariff administrator (ITA), the independent contract administrator (ICA) and others [10]. The ISO could also be a regional transmission group (RTG) with the authority and responsibility of operating a reliable transmission grid [16]. In Order 888, FERC did not require, but did encourage, the establishment of an ISO-type organization in each interconnected area.

The California's ISO is separated by several hundred miles from the power exchange, which is an organization where the energy bids are matched. The responsibilities of the ISO include ensuring that the schedules for use of the transmission system are feasible, operating the transmission system in real time, and settling financially with various parties who own and/or use the transmission systems [8].

2.1.4 Ancillary Services and the Service Markets

Ancillary services are those things necessary to support the delivery of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those

control areas to maintain RELIABLE operation of the inter-connected transmission system [4].

The unbundling of ancillary services from the basic transmission service is thought to promote greater economic efficiency in the electric industry. However, what kind of services are considered as an ancillary service and are able to be unbundled has been in controversy for some time. FERC proposed the following six ancillary services in its MegaNOPR: scheduling and dispatching service, reactive power/voltage control service, load following service, energy imbalance service, loss compensation service, and system protection service. It also asked for comments regarding them. The feedback varied. Different people, utilities and organizations may define their own set of ancillary services. To complicate matter further, different terms have been used to described the same services. In [21], three generation-related services and seven transmission-related services were proposed. They overlapped with the NOPR's services. In [6], five revised sets were discussed. Although their services were close to FERC's suggestion, different terms were used. The final rule of Order 888 divided the services into six ancillary services and several other interconnected services as listed in Section 1.1. However, different utilities are allowed to use their own subset of services according to their re-regulation models. For example, in California, six services are defined which are spinning reserve, non-spinning reserve, replacement reserve, regulation/AGC, voltage support and black-start capability [8].

Some of the services can be obtained from the competitive service market, where the services are regarded as commodities and are traded separately. The existence of markets for AGC, spinning reserve, non-spinning reserve and operating reserve services were assumed in [22]. For the services defined in [6], the authors claimed that the services of scheduling/dispatch and transmission voltage control can not be obtained competitively. Whether the market for generation voltage control is competitive depends on the specifics of each situation. In [23], the authors pointed out that the competitive markets for spinning reserve, non-spinning reserves, AGC, replacement reserve, voltage support and black start already have been setup and are now in operation in California. However, the last two services, i.e., black start capability and VAR support, are more suitable for purchasing, based on long-term contracts from among those units physically capable of providing such services.

2.2 Congestion Management

In this section, the papers relevant to congestion management and transaction adjustment are reviewed. Congestion is a consequence of various network constraints characterizing a finite network capacity that may limit the simultaneous delivery of power from an associated set of power transactions [24]. The network constraints include thermal limits, voltage/VAR requirements and the stability considerations. Among all the constraints, thermal limits are the most frequently considered factor in determining network capacity.

2.2.1 Traditional Congestion Management

Traditionally, the power transfer distribution factor(PTDF) method [25, 26] was used to manage the congestion. The PTDF refers to the sensitivity of line flow with respect to each transaction. A linear programming procedure was set up to maximize the total transfered power while ensuring that the thermal limits were not violated. The first contingency rule was also included in the constraints. Because of the uncertainties related to contingencies, a probabilistic approach was proposed in [27]. The authors applied the Wind Chime Diagram in the contingency selection, and determined a probabilistic simultaneous transfer capability using a linearized optimization procedure, whose objective function minimized the energy reduction.

2.2.2 Congestion Management in the New Climate

Congestion management in the competitive markets is discussed in [24, 28, 29]. In Reference [24], congestion management in a pool and a bilateral model was proposed. In the pool model, the optimal dispatch problem minimized the total net cost/benefit of individual buses. The cost of congestion was bundled with the nodal cost at each bus. In the bilateral model, the objective was to minimize the cost of congestion given the incremental and decremental bids submitted by generators. The bids represent a generator's willingness to pay to increase or decrease its output. The authors concluded that the nodal pricing seeks to provide the correct locational price signals, while in bilateral model, the central dispatch process is limited to the steps necessary for removing congestion.

A study of congestion management based on congestion pricing as might be done by an ISO was provided in [28]. It was based on quadratic cost coefficient estimates around a market solution and assumed that operators responsible for congestion management can use price signals of the generators to manage congestion. The marginal cost was inferred from an observation of the market prices. The solutions obtained under the rational economic behavior assumption are identical to the solution of an OPF. The authors concluded that the use of prices for congestion relief is separable from its use for the generation of transmission revenue.

The authors of [29] posed two questions regarding congestion management: (1) how will each transaction be modified in a non-discriminatory manner, and (2) who will modify the transactions? They proposed a minimum-distance redispatch method which disregards the economic value of the transaction adjustment. The rescheduled set of transactions is the closest point within the secure region. They further suggested that, under a competitive environment, a centralized operator could simply suggest a transaction adjustment for the market to use as a guide for a further round of negotiations.

2.3 Service Identification

In this section, papers related to the various aspects of service identification are reviewed. Section 2.3.1 covers the identification of load-following services and reserve services in a competitive environment. In Sections 2.3.2 and 2.3.3, papers related to the identification of reactive support service and real power loss services are discussed. Section 2.3.4 discusses some previously published cost evaluation methods for reactive power allocation and distribution of transmission losses.

2.3.1 Identification of Services in a Competitive Environment

In [22], the author proposed a method to select AGC, spinning reserve, non-spinning reserve and operating reserve services from various competitive service markets. A mixed-integer linear programming optimization method was used. The objective function minimized the cost of scheduling during the simulation time period. In the model that was adopted by the author,

the system operator also acts as an energy broker, so that the sellers bids will be selected by the same procedure as the services are identified.

A similar approach was also presented in [30], in which the spinning reserve and ready reserve requirement were identified by a linear programming method. Different from Reference [22], the objective function in [30] maximized the consumer's surplus in the energy and spinning reserve markets as well as minimized the cost of required system ready reserve. This was accomplished by including the price information of energy bids and reserve margin bids in the objective function. The energy bids of both the sellers and the buyers were selected together with the ancillary services.

In [23], ancillary services are procured by the ISO through a cost minimization procedure. However, different from the approaches in References [22, 30], the services are identified one by one. The sequence of auction is AGC, followed by spinning reserves, non-spinning reserves, and replacement reserves. This sequence allows capacity bids that are not selected in one auction to be considered in subsequent auctions.

2.3.2 Reactive Support Service Identification

Although there are few papers that address the reactive support service identification in a competitive environment, some of the traditional methods for solving the optimal reactive power dispatch problem can still be used.

Optimal reactive power dispatch can be used to determine the location and amount of reactive support for the system reliability. Several objective functions have been adopted for this optimization problem. Most authors have selected transmission loss minimization as the objective function [31, 32]. It determines the optimal generator voltage levels, the optimal switching of capacitor banks, and the optimal tap position for transformers, so that the minimum system losses can be achieved.

In [33], the authors applied minimum control action as the objective function. This minimum control action refers to the minimum necessary control for compensators and taps in order to reduce the associated depreciation cost.

In [34], the authors listed other objective functions such as maximization of reactive reserve margin, maximization of load voltages, etc. What kinds of objective functions to select depends on the different requirements of the users. The authors of [35] presented a general objective function to minimize the cost of reactive power, but how this cost is defined is not clearly stated.

Many optimization algorithms have been used to solve the reactive power dispatch problem, since it is a particular type of the optimal power flow. Linear programming was the most commonly mentioned method among the related literature as shown in References [32] and [36]. Other methods include Newton's method [37], the primal/dual method [38], evolutionary programming [39], and others.

2.3.3 Real Power Loss Service Identification

Identification of real power loss service includes the location and amount identification of generators that could provide extra energy for the transmission losses.

Traditionally, a swing bus is defined/identified to balance the mismatch between the generation and the load. This mismatch corresponds to the transmission losses because of the transmission line resistance. Usually, the largest generator in the system is selected as the swing bus. However, a single swing bus may concentrate the cumulative injection error and may cause an increase of transmission losses if the selected bus is far from the load center. Distributed swing buses were suggested in [40] as a method to solve this problem. The largest generator in each area is often chosen as the area swing bus.

Economic dispatch [11], the simplest form of OPF, was first used to determine each generator's output including the output for the loss support. The penalty factors, which were functions of loss sensitivities, were applied in the economic dispatch, so that the total real power production cost could be minimized. A broader sense of optimal power flow has also been applied into the determination of generators' output. Since power flow equations are included in the constraints, swing bus does not need to be specified.

2.3.4 Cost of Services

Both cost and price are important factors in the competitive market. They will affect the ISO's decision in identifying services and managing congestion. In this section, papers related to the cost of services are reviewed.

Although the authors of Reference [41] proposed nine types of transmission costs according to their corresponding economic meaning, some authors, see References [42] and [43], believed there are two main categories of transmission service cost: (1) embedded costs and (2) incremental (marginal) costs. Embedded costs are the costs associated with the original investment and the ongoing maintenances costs of existing transmission facilities. Incremental costs can be further decomposed [44] into operating costs, opportunity costs and reinforcement costs. Operating costs are the production costs because of generation redispatch and rescheduling resulting from the transactions. Opportunity costs correspond to the benefits unrealized because of the operating constraints that are imposed by the transactions. Reinforcement costs are the capital cost of all new transmission facilities needed to accommodate future transactions.

Related to transmission cost calculations, a summary of twelve generic classes of methods were presented in [41]. These methods include: (1) cost accounting and related analysis methods, (2) simple incremental and average cost methods, (3) contract path method, (4) megawatt-mile methods (5) rated system path method, (6) transmission cost actual path method, (8) general agreement on parallel path (GAPP) method, (9) allocated contract path method, (10) investment cost-related method, (11) nodal LRMC with expansion method, and (12) nodal SRMC method. Some representatives of the methods are discussed next.

Happ in [43] examined four embedded cost calculation methods: (1) postage stamp, (2) contract path, (3) boundary flow, and (4) megawatt-mile. The megawatt-mile method, which was first proposed by [45], turns out to be the most popular one because it considers actual flows and the transaction distances. Within incremental cost calculations, the short run marginal cost (SRMC) [43, 46, 47], which accounts for the additional operating costs in providing transmission services, has become the most popular method because of its economic basis. References [43, 48] discuss long run marginal costs (LRMC) in which additional rein-

forcement costs were considered. The concept of marginal cost was applied in spot pricing [49] of transmission services.

In [23], the opportunity costs of reserve and other capacity related services were proposed, which evaluate the cost of reserved capacity for inframarginal units (the units with marginal cost lower than market clearing price).

As far as the cost and price of reactive power is concerned, FERC's NOPR [4] suggested a fixed tariff for reactive power support. Another method, as proposed by [50, 51, 52, 53], was to use the node marginal cost. This marginal cost is the sensitivity of the generation production cost to the reactive power demand and is usually computed using an optimal power flow program. The authors of reference [54] claimed that the variable costs of producing reactive power are often negligible and consequently the charge for reactive power should be determined by the existence and availability of reactive power capacity. They further suggested several approaches to calculate the capacity value for reactive power. One approach is the usage of the triangular relation between the active, reactive and apparent power. Another approach is to use the costs of synchronous condensers as the valuation proxy. Cooperative game theory has also been suggested by the authors. In reference [35], a linear or quadratic reactive power total cost curve was assumed to be the cost of reactive power. But the authors didn't explain how they obtained this curve.

The transmission loss in this research refers only to the real power loss in MW form. The cost of this loss corresponds to the generators' cost in producing real power. This cost has already been extensively investigated. The text books in the area of power system operation, such as [11], have relevant information on the cost of real power production.

2.4 Service Allocation

The allocation algorithms that have been developed so far can be categorized into power flow-based, sensitivity-based methods and direct decomposition methods. In this section, these three methods are reviewed in Section 2.4.1, 2.4.2, and 2.4.3. Other allocation algorithms will be discussed in Section 2.4.4.

2.4.1 Power Flow-Based Methods

Power flow-based methods determine the allocation quantity by comparing power flow results with and without an individual transaction. In Reference [55], this method was used to allocate the losses. The author suggested to evaluate the loss that would occur for each transaction by assuming it were the first to be added on the system. A similar method was suggested in [56] for reactive power allocation. Slightly different from the above approach, the author in [57] suggested to calculate the incremental loss of each transaction as if the transaction were the last one added to the system.

As pointed out by the authors of [58], the full cost recovery can not be guaranteed by any of these approaches. The difference (mismatch) between the summation of individual transaction's effect and all transactions' composite effect may become significant under certain system conditions. The authors further suggested a revised algorithm, called aggregated allocation method, for service allocations that can eliminate the mismatch.

This aggregated allocation approach requires two power flow calculations for each transaction so that the "marginal component" and the "incremental component" could be obtained. The "marginal component" refers to the transaction's contribution as if the transaction were the first one added on the system. The "incremental component" is obtained as if the transaction were the last one added on the system. The average of the two is identified as the transaction's true contribution. This method actually combined the ideas used in [55] and [57]. Test results in [58] indicated that it is very accurate in allocating both the transmission losses and reactive power.

Another approach, see Reference [59], fully eliminates the mismatch by performing a series of power flows from the base case (without any transactions) to the final case (with all transactions) with each transaction added one at a time. In order to avoid the effect of transaction simulation order, an average power flow method was used by permutating all possible simulation orders.

2.4.2 Sensitivity-Based Methods

Sensitivity-based methods provide quick answers to service allocation. The sensitivities represent the incremental change in services with respect to the incremental change in transactions.

In Reference [55], the loss sensitivities for the base case were derived and evaluated. The multiplication of the sensitivity factor and the transaction amount determined the losses allocated to each transaction.

A similar approach was applied by the Mid-Continent Area Power Pool for loss compensation [60]. A loss percentage was defined. Its calculation required several power flow loss evaluations with and without a 50MW power block being transferred between the companies within the MAPP control area. This loss percentage actually has the same meaning as the loss sensitivity defined in [55]. But different approaches were used in the two papers to obtain the sensitivities.

Other sensitivity-based approaches, such as the ones proposed in [63, 64], involve the spot prices of the services. An optimal flow was set up to determine the spot price. This price can also be decomposed into the prices of individual services. The cost of service allocated to each transaction corresponds to the price difference between the buyer's point and the seller's point.

2.4.3 Direct Decomposition Methods

In this section, the allocation methods that are based on the direct decomposition of power flow are reviewed. A megawatt-mile method was proposed in [63, 64, 65] to allocate fix cost of basic transmission services. The allocation is based on the transaction's flow amount, flow direction, flow miles, reliability considerations, or the combinations of these factors. How to decompose the line flow is crucial to this method.

A popular approach is to apply the generalized distribution factors [66] to determine the transaction-related power flows. This approach was based on the D.C. linearized model of the system and, by using the superposition theorem, determined the impact of a particular load or generator on line flows. Reference [67] proposed a novel, topological approach to MW-

charging which determined the share, as opposed to the impact, of a particular generator or a load in every line flow. This topological approach was based on a recently proposed electricity tracing method [68] and resulted in positive generation and load distribution factors. A similar approach was proposed in [69] to allocate the transmission usage on the basis of traceable contributions of generators and loads to maximum line flows.

References [70, 71] presented a current decomposition method. In this approach, the operating point was determined using all scheduled transactions. It decomposed the complex current injection at each bus into the currents of individual transactions. Therefore, the complex power was decomposed into a major component and an interaction component. The major component corresponds to the individual transaction's contribution and the interaction component relates to the interaction between the transactions. The authors claims that, under normal operating conditions, the interaction component is a small percentage of the transaction itself. The same idea was used when the power flow formulation uses distributed slack buses. This method was suggested as a means to calculate the contributions of each ancillary service generation unit to each transaction.

2.4.4 Other Methods

A *Fixed tariff* was suggested by FERC's NOPR [4]. The tariff ranges from 3% for loss compensation to 1.0 mill per kwh for reactive power, load following and reserves. Thus, the allocation would be based on the transaction's actual usage times the unit price of the services.

Game theory recently emerged in power system applications. It was proposed in [72, 73, 74, 75] to allocate the cost-related to services. It was used to simulate the decision making process for defining the offered price in the deregulated environment. The transmission users are considered as the participants of a game. Their purposes are to maximize their profits. The strategies in playing the game, such as cooperative or non-cooperative, affect the cost of the services.

3 SERVICE IDENTIFICATION AND CONGESTION MANAGEMENT

In this chapter, a combined method that identifies services and determines transaction curtailment is proposed and developed. The proposed approach intends to maximize the overall profit of all market participants.

The limitations of previous methods are discussed in Section 3.1. After that, the cash flow among market participants is described in Section 3.2. This leads to a general optimization procedure, which is defined in Section 3.3 and 3.4 to solve the congestion management and service identification problems. The detailed analysis related to reactive support and real power loss services is provided in Chapter 5.

3.1 Limitation of Previous Methods

3.1.1 Limitation of Previous Congestion Management Methods

The limitations of previous congestion management methods include: (1) the selection of the power system model and (2) the formation of the objective function.

Previously, a DC model was used to management congestion. Traditional approaches, as discussed in [25, 26], used the DC power transfer distribution factor (PTDF) to evaluate how the change of transactions would affect the line flows. In Reference [24], an H matrix was applied in managing congestion under both the pool model and the bilateral model. H is a matrix of bus-branch distribution factors that maps changes in nodal injections to changes in flows. This matrix was derived by assuming a linearized representation of the system, which is commonly referred to as the "DC power flow".

The DC model used in deriving distribution factors has the advantage of easy calculation. However, when the reactive power is ignored, the line flows may be significantly in error.

Using the DC model for managing congestion may underestimate the transmission capability and therefore lead to an unnecessary amount of curtailment.

Another problem with the previous congestion management methods is the objective function. Most of the approaches minimize the total energy curtailment, as suggested by [25, 26, 27] and [29]. Other methods require the minimization of net cost [24, 28] or the minimization of adjustment cost [24].

In the competitive market environment, purely minimizing the total energy curtailment fails to provide correct price signals to the market participants. The minimization of cost is a feasible objective function. However, how this cost is determined and whether this information is available to system operators is still not totally clear. Moreover, in some literature [24], the minimized congestion cost is suggested to be paid by the transmission users to the transmission owners. This may mislead the owners to lower transmission limits, so that they can earn more because of the congestion.

3.1.2 Limitation of Previous Service Identification Methods

Previously, the service identification methods in the competitive markets included a series of cost minimization procedures [23] which identified the services of AGC, spinning reserve, non-spinning reserve and replacement reserve one by one. However, these services are the joint products of generators. How and why this identification sequence is defined is not clear. Another two methods [22, 30] identify these services simultaneously through the overall cost minimization or consumer surplus maximization.

However, there is not much literature regarding the competitive procurement of reactive services and transmission loss services.

Traditionally, the objective functions of reactive power dispatch were mainly loss minimization [32, 36], control action minimization [33] and etc. Those functions are more or less focused on the technical side of reactive support and often lack economic meaning. A general objective function was presented recently [35] that minimizes the cost of reactive power, but how this cost is composed of is not easily interpreted.

The selection of a swing bus is crucial in both the congestion management and reactive support identification, since a different swing bus will affect the power flow results and the resultant sensitivities. In most of the approaches discussed in Sections 2.2 and 2.3, a single swing bus was assumed. However, whether this swing bus is optimal in the sense that it satisfies the objective function purpose or whether a distributed swing bus is required has not been analyzed.

3.1.3 Separating Congestion Management and Service Identification

Separating congestion management and service identification ignores the technical interdependence between these two functions. In Reference [28], the authors indicated that congestion can be relieved by the operation of transformer taps and other forms of service. However, the general recognition that optimization of reactive power costs can be decoupled from real power without significant consequences [24] results from the ignorance of this technical interdependence.

Considering the above limitation, a general optimization procedure was developed in this research which maximizes the overall lower bound profit while simultaneously determining the necessary transaction adjustment and identifying the appropriate service levels.

3.2 Cash Flow among the Market Participants and the ISO

Before discussing how the ISO should manage congestion and identify the necessary services, this work will first present how money flows between the market participants and the ISO. This cash flow is based on the market assumption that the energy market uses the double-auction and bilateral models, while the service markets use the single-auction models. Since this research involves a day-ahead scheduling function, Figure 3.1 represents the money that is expected to be exchanged for the scheduled energy and services.

There are nine main cash flows in between the energy buyers, energy sellers, the ISO and the service providers. They are shown in Figure 3.1 and are described in the following part.

1. Revenue of energy buyer t: $\mathcal{R}_t^{ebuyer}$ $(t = 1, \cdots, nt)$

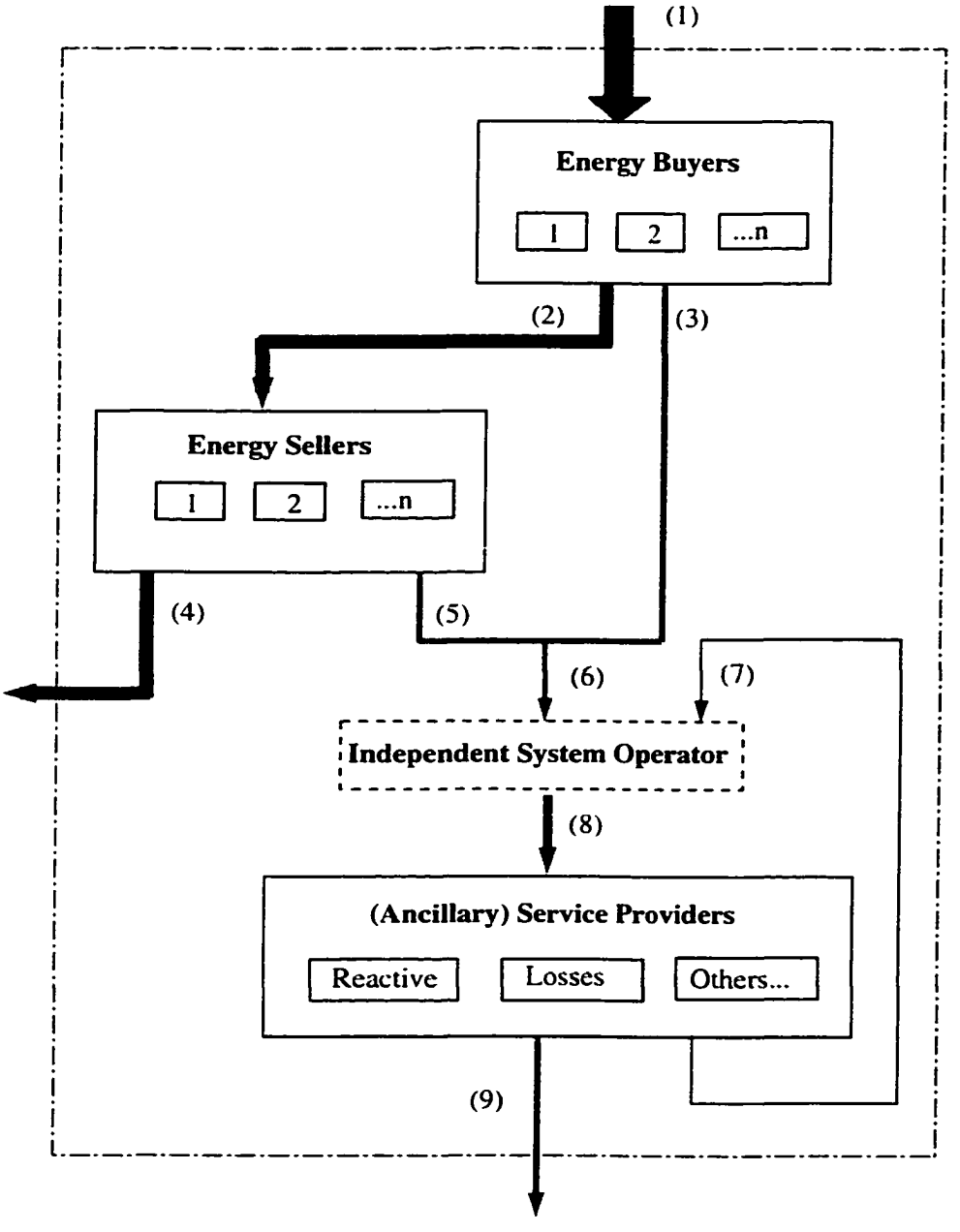


Figure 3.1 Cash flow among market participants and the ISO

In this research, the distribution system is assumed to be a monopoly. Customers must buy energy from their local distribution companies, who, in the energy market, act as the wholesale buyers. The revenue received by buyer t is denoted by $\mathcal{R}_t^{ebuyer}$, which is expressed by Equation 3.1.

$$\mathcal{R}_t^{ebuyer} = \mathcal{P}r_t^{ebuyer} * P_t^p - \mathcal{C}_{adj,t}^{ebuyer} * \Delta P_t \tag{3.1}$$

The first term represents the expected total revenue if there is no congestion, where $\mathcal{P}r_t^{ebuyer}$ is the unit retail price for buyer t and P_t^p is the proposed amount of energy that buyer t is going to resell. The actual scheduled amount is denoted by P_t which equals to $P_t^p - \Delta P_t$. Since distribution is a monopoly, $\mathcal{P}r_t^{ebuyer}$ will be a function of P_t^p.

The second term corresponds to the loss of revenue if proposed energy is curtailed by ΔP_t. $\mathcal{C}_{adj,t}^{ebuyer}$ is the per unit revenue, or in other words, cost of adjustment. In general, $\mathcal{C}_{adj,t}^{ebuyer}$ is no less than $\mathcal{P}r_t^{ebuyer}$.

2. Revenue of energy seller t: $\mathcal{R}_t^{eseller}$ $(t = 1, \cdots, nt)$

   The revenue of energy seller t, $\mathcal{R}_t^{eseller}$, comes from the energy that is scheduled to be sold to the energy buyer t in the energy market. It is expressed as:

$$\mathcal{R}_t^{eseller} = \mathcal{P}r_t^{eseller} * P_t \tag{3.2}$$

   where $\mathcal{P}r_t^{eseller}$ corresponds to the unit price (wholesale price) of energy in the market or the energy price agreed between the buyer and the seller. This $\mathcal{R}_t^{eseller}$ is paid by the energy buyer t.

3. Cost of service for energy buyer t: $\mathcal{C}s_t^{ebuyer}$ $(t = 1, \cdots, nt)$

   Ancillary services and other interconnected services are needed for the system security and reliability. Since there are costs related to these services, these costs should be shared by all transmission users. The cost that the energy buyer t should pay is expressed by Equation 3.3.

$$\mathcal{C}s_t^{ebuyer} = \sum_k \mathcal{P}r_k^{sprovider} * SV_{k,t}^{ebuyer} \tag{3.3}$$

where $\mathcal{P}r_k^{sprovider}$ corresponds to the per unit price of the service that is supplied by producer k. $SV_{k,t}^{ebuyer}$ is the amount of service provided by producer k to buyer t.

4. Cost of energy production for seller t: $\mathcal{C}e_t$ $(t = 1, \cdots, nt)$

   There are many costs related to energy production. For proposed energy amount, these costs include the capital investment, the maintenance and labor cost, the fuel cost, and the opportunity cost. Moreover, when congestion occurs, there exists a curtailment cost. Generally, for each individual energy seller, these cost are functions of the individual production level as expressed in Equation 3.4.

$$\mathcal{C}e_t = \mathcal{C}e_t(P_t^p) + \mathcal{C}_{adj,t}^{eseller} * \Delta P_t \tag{3.4}$$

5. Cost of service for energy seller t: $\mathcal{C}s_t^{eseller}$ $(t = 1, \cdots, nt))$

   As the energy sellers are also transmission users, they should pay for their costs of service. Let $SV_{k,t}^{eseller}$ represent the amount of service provided by producer k to seller t, then the cost of service for energy seller is

$$\mathcal{C}s_t^{eseller} = \sum_k \mathcal{P}r_k^{sprovider} * SV_{k,t}^{eseller} \tag{3.5}$$

6. Cost of service for the energy transaction t: $\mathcal{C}s_t^{etrans}$ $(t = 1, \cdots, nt)$

   The decision of which parties in a transaction should be responsible for the service cost is not of the interest in this research, as long as the total cost will be paid. Generally the service cost is denoted in terms of transaction, which is expressed by Equation 3.6.

$$\mathcal{C}s_t^{etrans} = \mathcal{C}s_t^{ebuyer} + \mathcal{C}s_t^{eseller} \tag{3.6}$$

7. Cost of service paid by service provider k: $\mathcal{C}s_k^{sprovider}$ $(k = 1, \cdots, ns)$

Service producers are also transmission users. They should pay for their part of the service costs. For example, a loss provider should pay the cost of reactive support and reactive power producers should pay the cost of reserves. Although in most cases, this cost is comparatively small, it is still one part of the cash flow.

Equation 3.7 provides an expression for this cost. $SV_{m,k}^{sprovider}$ corresponds to the amount of service that is provided by service producer m to producer k. $\mathcal{P}r_m^{sprovider}$ is the per unit price of the service m.

$$\mathcal{C}s_k^{sprovider} = \sum_m \mathcal{P}r_m^{sprovider} * SV_{m,k}^{sprovider} \tag{3.7}$$

8. Revenue of service provider k: $\mathcal{R}_k^{sprovider}$ $(k = 1, \cdots, ns)$

   The total revenue of service producer comes from the selling of services to the energy market participants and the other service producers.

$$\begin{aligned} \mathcal{R}_k^{sprovider} &= \mathcal{P}r_k^{sprovider} * SV_k \\ &= \textstyle\sum_t \mathcal{P}r_k^{sprovider} * (SV_{k,t}^{eseller} + SV_{k,t}^{ebuyer}) + \sum_m \mathcal{P}r_k^{sprovider'} * (SV_{m,k}^{sprovider}) \end{aligned} \tag{3.8}$$

9. Cost of service production for service provider k: $\mathcal{C}s_k$ $(k = 1, \cdots, ns)$

   These are the costs related to the service production. These costs are composed of explicit costs and opportunity costs, and they are functions of the service levels as shown in Equation 3.9.

$$\mathcal{C}s_k = \mathcal{C}s_k(SV_k) \tag{3.9}$$

Table 3.1 summarizes the above cash flows.

Table 3.1 Cash flow between market participants and the ISO

	Description	Paid by	Paid to
(1)	revenue of energy buyers $\mathcal{R}_t^{ebuyer}$	energy consumers	energy buyers
(2)	revenue of energy buyers $\mathcal{R}_t^{eseller}$	energy buyers	energy sellers
(3)	cost of service for energy buyers $\mathcal{C}s_t^{ebuyer}$	energy buyers	the ISO
(4)	cost of energy production $\mathcal{C}e_t$	energy sellers	other related entities
(5)	cost of service for energy sellers $\mathcal{C}s_t^{eseller}$	energy sellers	the ISO
(6)	cost of service for energy transactions $\mathcal{C}s_t^{etran}$	energy transactions	the ISO
(7)	cost of service paid by service providers $\mathcal{C}s_k^{sprovider}$	service providers	service providers
(8)	revenue of service providers $\mathcal{R}_k^{sprovider}$	the ISO	service providers
(9)	cost of service production $\mathcal{C}s_k$	service providers	other related entities

3.3 General Objective Function: Profit Maximization

3.3.1 Individual Profit of Market Participants

The cash flows described in previous section have significant impacts on the behavior of market participants who participate in the market mainly for their profit maximization. The profit of the market participants can be evaluated according to Figure 3.1 and Equations 3.1 to 3.9.

The profit of the energy buyer t is his revenue minus his total cost of energy bought from the energy market plus his cost for various services.

$$\begin{aligned}\pi_t^{ebuyer} &= \mathcal{R}_t^{ebuyer} - \mathcal{R}_t^{eseller} - \mathcal{C}s_t^{ebuyer} \\ &= \mathcal{P}r_t^{ebuyer} * P_t^p - \mathcal{C}_{adj,t}^{ebuyer} * \Delta P_t - \mathcal{P}r_t^{eseller} * P_t - \textstyle\sum_k \mathcal{P}r_k^{sprovider} * SV_{k,t}^{ebuyer}\end{aligned} \tag{3.10}$$

The profit of the energy seller t is his income in the energy market minus his total cost of energy production plus his cost for various services.

$$\begin{aligned}\pi_t^{eseller} &= \mathcal{R}_t^{eseller} - \mathcal{C}e_t - \mathcal{C}s_t^{eseller} \\ &= \mathcal{P}r_t^{eseller} * P_t - \mathcal{C}e_t(P_t^p) - \mathcal{C}_{adj,t}^{eseller} * \Delta P_t - \sum_k \mathcal{P}r_k^{sprovider} * SV_{k,t}^{eseller}\end{aligned} \tag{3.11}$$

The profit of the service provider k is his income in the service markets minus his cost of service production plus his cost for other services.

$$\begin{aligned}\pi_k^{sprovider} &= \mathcal{R}_k^{sprovider} - \mathcal{C}s_k - \mathcal{C}s_k^{sprovider} \\ &= \mathcal{P}r_k^{sprovider} * SV_k - \mathcal{C}s_k(SV_k) - \sum_m \mathcal{P}r_m^{sprovider} * SV_{m,k}^{sprovider}\end{aligned} \tag{3.12}$$

The ISO is a not-for profit entity. The overall flow-in money of the ISO must equal the overall out flow of money.[1] The equality in Equation 3.13 must hold.

$$\sum_t \mathcal{C}s_t^{etrans} + \sum_k \sum_m \mathcal{P}r_m^{sprovider} * SV_{m,k}^{sprovider} = \sum_k \mathcal{R}_k^{sprovider} \tag{3.13}$$

3.3.2 Overall Profit Maximization

From the Equations 3.10 through 3.12, the profit of market participants is directly related to the levels of energy scheduled ($P_t = P_t^p - \Delta P_t$) and the service levels scheduled (SV_k). Although the proposed transactions and service bids are provided by the individual market participants, the final accepted transactions and the required services are determined by the ISO through the congestion management and service identification.

Since the ISO's decision will affect the participants profit, it can not simply maximize a particular user or a particular group of users' profit. In order to guarantee a non-discriminatory open access, the overall profit of all market participants should be considered. This overall profit is defined in Equation 3.14.

$$\pi = \sum_{t \in ebuyer}^{nt} \pi_t^{buyer} + \sum_{t \in eseller}^{nt} \pi_t^{eseller} + \sum_{k \in sprovider}^{ns} \pi_k^{sprovider} \tag{3.14}$$

[1]Sometimes, a small amount of operating fee should be subtracted.

Substituting Equations 3.10, 3.11, 3.12 and 3.13 into Equation 3.14, the overall profit becomes:

$$\begin{aligned}
\pi &= (1) - (4) - (9) \\
&= \textstyle\sum_t^{nt} \mathcal{P}r_t^{ebuyer} * P_t^p - \sum_t^{nt} \mathcal{C}_{adj,t}^{ebuyer} * \Delta P_t && \text{(revenue of energy buyers)} \\
&- \textstyle\sum_t^{nt} \mathcal{C}e_t(P_t^p) - \sum_t^{nt} \mathcal{C}_{adj,t}^{eseller} * \Delta P_t && \text{(cost of energy production)} \\
&- \textstyle\sum_k^{ns} \mathcal{C}s_k(SV_k) && \text{(cost of service production)}
\end{aligned} \tag{3.15}$$

The above expression of overall profit can also be seen from Figure 3.1, where, the net money is the profit summation of all market participants.

Therefore, in order to guarantee non-discriminatory open access, the ideal objective function for congestion management and service identification would be to maximize the overall profit, i.e.,

$$\begin{aligned}
\underset{\Delta P_t,\, SV_k}{Maximize\ \pi} &= \textstyle\sum_t^{nt} \mathcal{P}r_t^{ebuyer} * P_t^p - \sum_t^{nt} \mathcal{C}e_t(P_t^p) \\
&- \textstyle\sum_t^{nt} (\mathcal{C}_{adj,t}^{ebuyer} + \mathcal{C}_{adj,t}^{eseller}) * \Delta P_t - \sum_k^{ns} \mathcal{C}s_k(SV_k)
\end{aligned} \tag{3.16}$$

where, each participant in the energy and service markets are treated equally in terms of the expected profit.

3.3.3 Maximizing the Lower Bound Profit

From the previous analysis, the overall profit π depends on the retail price $\mathcal{P}r_t^{ebuyer}$, the cost of energy production $\mathcal{C}e_t$, the cost of service production $\mathcal{C}s_k$, and the cost of adjustment $\mathcal{C}_{adj,t}^{ebuyer}$ and $\mathcal{C}_{adj,t}^{eseller}$ However, this price/cost information is not generally available to the ISO unless the markets are fully competitive, and the marginal costs equal to the market prices.

In the energy and service markets that have come in to existence to date, and are planned for in the near future, some barriers to entry and exit exist. They are imperfect competitive markets and it is impossible for the ISO to have access to the complete cost information.

Although the information needed for congestion management and service identification is not explicitly available to the ISO, it is reflected by the bid price stored in the DB1 and DB3, as shown in Figure 1.1.

In the energy market, the buy bid $pr_{b,t}$ for an energy buyer t represents his willingness to pay for a unit of energy. This bid generally reflects the retail price $\mathcal{P}r_t^{ebuyer}$ that is at least acceptable by the consumers. Since rational behavior of the energy buyer and seller is assumed, the per unit buy bid must be no greater than the per unit retail price, i.e.

$$pr_{b,t} \leq \mathcal{P}r_t^{ebuyer} \tag{3.17}$$

In the energy market, the sell bid $pr_{s,t}$ for an energy seller t represents his willingness to sell for a unit of energy. Under the rational behavior assumption, this bid should at least be able to cover the cost of energy production, i.e.

$$pr_{s,t} \geq \mathcal{C}e_t / P_t^p \tag{3.18}$$

In the energy market, the adjustment bid for a buyer $pr_{b,t}^a$ represents his "willingness" to be adjusted. This cost must be at least greater than the true cost $\mathcal{C}_{adj,t}^{ebuyer}$ (Equation 3.19), since a higher cost indicates a possible lower amount of curtailment. For a similar reason, same relationship holds for the seller (Equation 3.20).

$$pr_{b,t}^a \geq \mathcal{C}_{adj,t}^{ebuyer} \tag{3.19}$$

$$pr_{s,t}^a \geq \mathcal{C}_{adj,t}^{eseller} \tag{3.20}$$

In the service market, the sell bid $p_{sv,k}$ for a service provider k represents his willingness to sell a unit of service, at this price. Under the rational behavior assumption, this bid should at least be able to cover the cost of service production, i.e.

$$pr_{sv,k} \geq \mathcal{C}s_k / SV_k \tag{3.21}$$

Substitute inequalities 3.17 to 3.21 into Equation 3.15, the overall profit is rewritten as:

$$\pi \geq \pi_1 = \sum_t^{nt} pr_{b,t} * P_t^p - \sum_t^{nt} pr_{s,t} * P_t^p - \sum_t^{nt} (pr_{b,t}^a + pr_{b,t}^a) * \Delta P_t - \sum_k^{ns} pr_{sv,k} * SV_k \tag{3.22}$$

where π_l is a lower bound of overall profit.

Maximizing the overall profit is now turned into a lower bound profit maximization problem (Equation 3.23). In the short run, this, in general, is only an approximation to the optimal solution. However, in the long run when the markets are assumed to be fully competitive, this will guarantee the overall profit maximization.

$$\begin{aligned} \underset{\Delta P_t,\, SV_k}{Maximize\ \pi_l} &= \sum_t^{nt} pr_{b,t} * P_t^p - \sum_t^{nt} pr_{s,t} * P_t^p \\ &\quad - \sum_t^{nt} (pr_{b,t}^a + pr_{s,t}^a) * \Delta P_t - \sum_k^{ns} pr_{sv,k} * SV_k \end{aligned} \tag{3.23}$$

Such a lower bound maximization problem can be categorized into a "MaxMin" strategy, which is frequently used in decision making.

3.3.4 Minimizing the Upper Bound Cost

As the proposed transactions P_t^p are known when the ISO manages the congestion and selects the necessary services, the objective function of lower bound profit maximization can be converted into an upper bound cost minimization problem which is expressed in Equation 3.24.

$$\underset{\Delta P_t,\, SV_k}{Minimize\ Cost} = \left[\sum_t^{nt} (pr_{b,t}^a + pr_{s,t}^a) * \Delta P_t\right] + \sum_k^{ns} pr_{sv,k} * SV_k \tag{3.24}$$

The first term in Equation 3.24 stands for the total congestion cost, where $(pr_{b,t}^a - pr_{s,t}^a)$ is the upper bound cost for transaction t when a single unit of energy is curtailed. The second term represents the upper bound of the true service cost. It corresponds to the cash flow (8) in Figure 3.1 that is purchased by the ISO from the service providers.

The objective function in Equation 3.24 can be used to identify services and manage congestion simultaneously. In case that the proposed transactions do not cause any violations, the objective function will only include the second term, which minimizes the total cost of services.

In case the proposed transactions cause the security violation, the congestion cost will not serve as the transmission revenue generator as proposed in Reference [24]. It represents the upper bound loss of profit for each transaction, which is compatible with the cost of service. In this way, the coupling between congestion management and service identification is handled.

Although it seems that the energy market participants have the incentive to overbid the cost of adjustment, the remaining transaction will have to pay the high cost of services. This may encourage the participants to adjust their bids for next submission.

3.4 General Constraints

Given the objective function defined in previous section, the solution of the service identification and congestion management must satisfy the constraints, which represent the requirement of the system operation. These constraints are categorized into equalities and inequalities.

3.4.1 Active Equalities

The set of equalities always includes the power flow equations for scheduled load and generations.

1. Power flow constraints

$$\begin{aligned} \overline{P} + \overline{\Delta P} &= Re(\overline{V}.*\overline{I}^*) \\ \overline{Q} + \overline{\Delta Q} &= Im(\overline{V}.*\overline{I}^*) \end{aligned} \tag{3.25}$$

   These constraints represent the conservation of power at each bus $\overline{P}$ and $\overline{Q}$ stand for the real and reactive power injection at the base case. $\overline{\Delta P}$ and $\overline{\Delta Q}$ are the incremental real and reactive power injection because of the transactions and the services. $\overline{V}$ and $\overline{I}$ are the vectors of bus voltage and current in the final case.

2. Power balance constraints

$$\begin{aligned} \textstyle\sum_g P_g &= \textstyle\sum_d P_d + P_l \\ \textstyle\sum_g Q_g &= \textstyle\sum_d Q_d + Q_l \end{aligned} \tag{3.26}$$

   These constraints represent the power conservation for the complete network. P_g and Q_g stand for the real and reactive power output for generator g, while P_d and Q_d are the real and reactive power of load d. The real and reactive power loss are represented by the P_l and Q_l.

3.4.2 Inequality Constraints

The following quantities have upper and/or lower limits that must be satisfied.

1. Dispatchable sources of transactions and services.

   These sources includes the curtailable transactions (Equation 3.27) and the sources of services (Equation 3.28).

$$0 \leq \Delta P_t \leq P_t^p \tag{3.27}$$

$$0 \leq SV_k \leq SV_k^p \tag{3.28}$$

   Equation 3.27 indicates that the adjustment of each transaction should not exceed the proposed transaction level P_t^p. Equation 3.28 is a general description of service limits. Since a single-auction model was assumed in this research for service markets, the identified services should not exceed the proposed service bids (S_k^p).

2. Variables

   This refers to the constraints on the state variables, such as the voltage, the phase angles, the tap positions. Equation 3.29 is a typical voltage constraint for any load or generator bus.

$$V_{i,min} \leq V_i \leq V_{i,max} \tag{3.29}$$

3. Functions

   There are also constraints that must be enforced for the reliable operation of the power system. These constraints are, in most cases, functions of the state variables, such as the line flow, measure of security and etc. A general expression is given in Equation 3.30. However, for different functions, it may be more convenient to adopt other forms of this

expression. In some cases, such an explicit form of function limits may not even be available.

$$f_{min} \leq f(V_i, \delta_i, \cdots) \leq f_{max} \tag{3.30}$$

3.5 Summary

In this chapter, a general optimization procedure is defined and developed to determine the appropriate transaction curtailment while identifying necessary services. Through the analysis of the major cash flows, the ideal objective function was defined to maximize the overall profit, where each participant is treated equally in term of profit, so that the non-discriminatory transmission open access is guaranteed. Because of limited available information, a lower bound profit maximization was identified as a substitute objective function. It changed the power system operation into a price-based operation. Therefore, the ISO's decision in congestion management and service identification will depend on the cost of congestion and cost of services, which are reflected by the buy and sell bids in the energy markets and service markets.

Among various services that are traded in the market, only the reactive support service and real power loss service are included in this research. In next chapter, the evaluation of the cost and bid prices of the two services are presented.

4 COST AND PRICE OF REACTIVE SUPPORT AND LOSS SERVICES

In previous chapter, a general optimization procedure for the ISO to identify service and manage congestion was proposed. Although this procedure is flexible enough to identify all the services, the intention of this research is to identify the reactive support and real power loss service. This involves the cost and bid price evaluation of these two services, which is the individual behavior of market participants.

In this chapter, the process for evaluating costs and determining bids are analyzed. The sources of reactive support and real power loss services are presented in Section 4.1. After that, the analytic framework for economic cost analysis is discussed in Sections 4.2 through 4.5. How to prepare the bid for the two services is briefly presented in Section 4.6.

4.1 Sources of Reactive Support Service and Real Power Losses

4.1.1 Sources of Reactive Support Service

The service of reactive supply and voltage support comes from both the generation sources and the transmission sources.

- generation sources

  Generators are important sources of reactive power and voltage support. They can work at leading or lagging power factors so that reactive power can be delivered to or absorbed from the power system. The generator voltages, which are controlled by the excitors, also have important effect on the voltage level of the entire system.

- transmission sources

Transmission sources provide local reactive power and voltage support. These sources includes the tap-changing transformers, capacitor banks, static voltage compensators, Synchronous compensators, and various shunt or serial reactive compensation devices. Besides that, the shunt of high voltage transmission lines are also sources of reactive power.

Except for the reactive power from transmission lines, all the other sources of reactive supply and voltage support can be scheduled and controlled by the operator.

The reactive power from generators can be traded on the reactive power market, which is a market separated from the real power markets and other service markets. For reactive support from transmission sources, as the transmission system is assumed to be monopoly, there is no market for these sources. However, the operation of these devices will be based on the technical and cost factors and are under the supervision of the system operators.

4.1.2 Sources of Real Power Loss Service

Different from the service of reactive support, generators are the only producers of the real power. Although other factors, such as the location and amount of reactive support, will affect the level of real power losses, the generators are the direct providers of real power loss service.

In the real power loss market, the suppliers could submit their bids to show their willingness to provide extra energy for the transmission losses.

4.2 Economic Cost Analysis

The cost of services is reflected in the objective function and it will affect the service identification results. In Section 2.3.4, several types of cost were identified from various literature sources and include such items as embedded cost, marginal cost, operating cost, and reinforcement cost. They correspond to the different aspects of the cost for evaluating transmission usage and ancillary services. In this research, the cost of interest refers to the "economic cost". It represents the true overall cost.

According to [76], the economic cost consists of the explicit and implicit costs. Explicit costs are the costs that must be paid directly. They include the capital costs of the facilities and the operating costs of production. Implicit costs mainly refer to opportunity costs, which are defined as the value of something in its next best employment.

The following example illustrates the meaning of explicit costs and implicit costs. Suppose a professor, earning $40,000 per year, decided to quit academia to start a computer software business. Two part-time students programmers are each hired at $500 per month ($6,000 per year) and they work in an apartment that the professor rents for $500 per month ($6,000 per year). The utility bill runs $300 per month ($3,600 per year). Table 4.1 summarizes the professor's costs.

Table 4.1 Example of explicit cost and implicit cost

Type of Cost	Resource	Amount
Explicit Costs	Hired labor	$12,000
	Rental of apartment	$6,000
	Utilities	$3,600
Implicit Cost	Salary in Academia	$40,000
Economic Cost		$61,600

The total explicit costs are $21,600. However, to that the implicit opportunity costs must be added, which is the income $40,000 that could have been earned in adademia. This cost represents the opportunity cost for the professor to run his own business instead of working in academia. Until the professor's revenues exceed $61,600 per year, there is no economic profit.

Opportunity cost is a hot topic today in financial managment. It constitutes an important part of the economic cost. In the deregulated environment, since each market participant is actually a financial entity, the same concept of economic cost should be applied in evaluating the cost of services. Hence, the profit discussed in previous chapter is actually the economic profit and it measures the entity's true profitability.

In this chapter, Section 4.3 discusses the economic costs related to generation sources and Section 4.4 discusses the economic costs related to transmission sources.

4.3 Economic Cost of Generation Sources

In a deregulated environment, energy in the form of real power is not the only commodity that is produced by a generator and is traded in a free market. As analyzed in Section 4.1, a generator could not only provide reactive support service, but also real power loss service. Other services, such as operating reserve service, are also products of generation.

The energy in the form of real power and the above services are traded in seperate markets. Their cost evaluation is coupled with each other. This coupling directly reflects the coupling between the real and reactive power and the capacity limit of a generator. Therefore, we categorize these services into real-power related services and reactive-power related services, as listed in 4.2. All of these services will be a part of the capacity usage of a generator.

Table 4.2 Real and reactive power related sevices

Real power related	Reactive power related
Real power loss service	Reactive supply and voltage control
Spinning reserve service	Reactive power reserve (future)
Supplemental reserve service	
Energy imbalance service	
Regulatory and frequency response service	

4.3.1 Explicit cost

The explict costs for services from a generator include: (1) the operating cost which corresponds to fuel and maintenance cost, and (2) the capacity cost that represents the capital cost investment for the generation devices.

4.3.1.1 Operating Cost

Operating cost includes the fuel cost for a fossil-fired steam unit and the prorated operation and maintenance costs. The latter mainly refers to the labor cost for the operating crew. This cost should be included as part of the operating cost if it can be expressed directly as a function of the unit output.

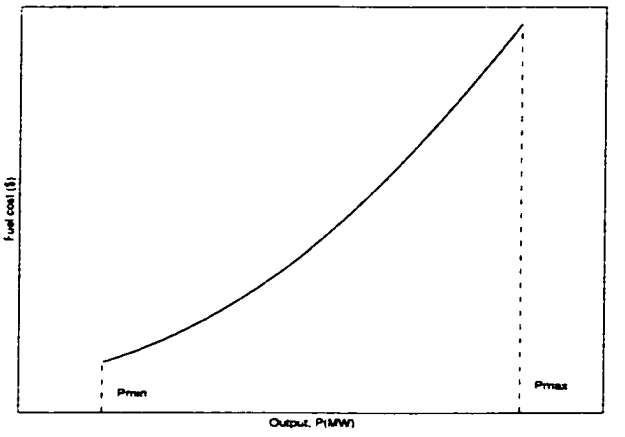


Figure 4.1 Ideal fuel cost curve for a steam unit

Fuel cost constitutes a major portion of the operating cost for a fossil-fired steam unit. This cost is a function of the unit input-output curve and the per unit fuel price. Figure 4.1 shows the fuel cost curve in an idealized form, neglecting the impact of valve loops.

Generally, a quadratic cost function or a reduced qubic function (Equation 4.1) is used to express the relationship between the fuel cost and the real power output. This fuel cost corresponds directly to the cost of electricity and the cost of real power related services, such as the real power loss service.

$$\begin{aligned} C_{fuel} &= a_g P^2 + b_g P + c_g \\ C_{fuel} &= a_g P^3 + b_g P^2 + c_g P + d_g \end{aligned} \tag{4.1}$$

For reactive power related services, there is little or no fuel cost[1] that is directly related. Operating costs thus correspond to the small amount of required maintenance costs. The capacity cost, which represents the capital cost of capacity used to produce reactive power Q, constitutes the largest part of its explicit cost.

4.3.1.2 Capacity Cost

Traditionally, the capacity cost of a generator has been specified in terms of the real power P ($\$/MW$) operating at nominal power factor. However, the capacity of the generator is used

[1]There might exist little cost of maintaining generator's and excitation equipment.

to produce not only the electricity in form of real power P, but also the reactive power Q and various other real and reactive power related services. The per unit capital cost, PUC_S, in terms of the capacity S, is a more proper term in defining the capital cost of a generator. It can be derived from the following equation:

$$PUC_s = \$/MW * pf \tag{4.2}$$

where, pf is the nominal power factor of the generator.

Economically, the electricity, the real and reactive power related services are joint products of a generator's capacity. They occupy the capacity for producing (real and reactive power production) or to produce (real and reactive power reserve). They are non-separable and must satisfy the following expression:

$$PUC_s * S = PUC_p * P + PUC_q * Q \tag{4.3}$$

where, PUC_p and PUC_q are the per unit capacity cost of real power and reactive power related products respectively.

However, as the these commodities are traded in separate markets, a reasonable approach (although it might be arbitrary) to separating them must be found. The power triangle in Figure 4.2 is suggested by [54] to define the cost components in terms of real and reactive power:

$$\begin{aligned} PUC_p &= PUC_s * cos(cos^{-1}pf) \\ PUC_q &= PUC_s * sin(cos^{-1}pf) \end{aligned} \tag{4.4}$$

4.3.2 Opportunity cost

4.3.2.1 Opportunity cost and generator capability

The opportunity cost of a generation-related service is the value of the generation capacity for the next best alternative usage. A generator's loading capability diagram [77], plays an important role in calculating the opportunity cost. This capability diagram represents the

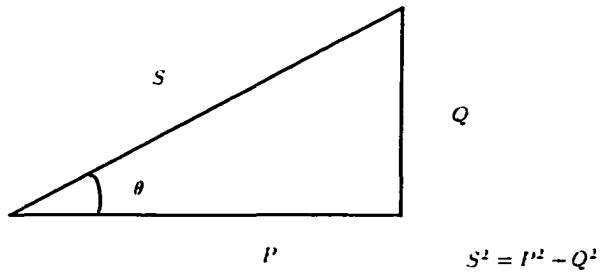


Figure 4.2 Triangular relationship between P, Q and S

restrictions on the operation of a generator, which is limited by the synchronous generator armature current limit, the field current limit, and the underexcitation limit. Figure 4.3 shows an ideal loading capability diagram. Because of these limits, the production of one generation-related service may prevent some other alternative capacity usages. The highest value of the alternative capacity usage is defined as the opportunity cost.

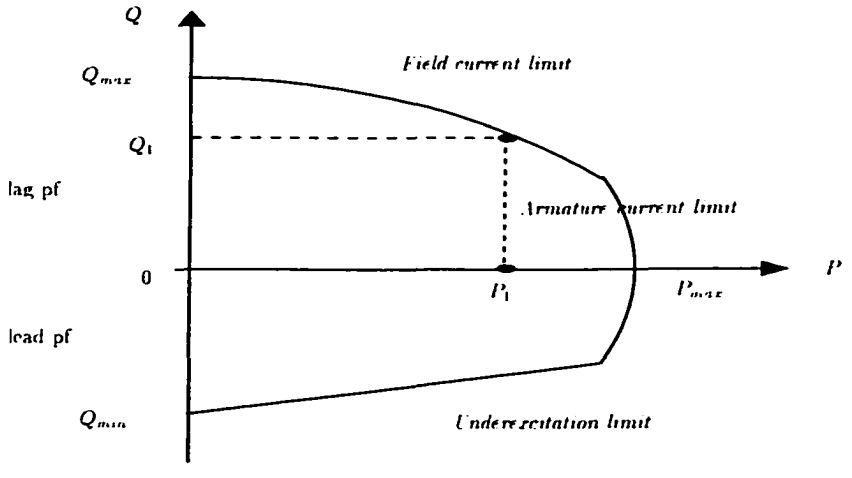


Figure 4.3 Loading capability diagram

For a better illustration, let's assume the capacity of a generator is used only for producing (1) energy in real power, which is traded in the energy market, (2) the real power loss service, which is traded in the real power loss market, and (3) the reactive power, which is traded in the reactive support service market. Further assume all the three markets are always available.

According to the definition of opportunity cost, the value of the alternative capacity usage for one of the commodities, say, reactive power Q, is the profit of the real power energy (π_p^{erg})

or the profit of loss service (π_p^{loss}) that can not be achieved by producing Q. The maximum profit of the two corresponds to the opportunity cost of Q, which is shown in Equation 4.5.

$$OC_q(Q) = max(0, \pi_p^{erg}(P), \pi_p^{loss}(P)) \tag{4.5}$$

A similar expression, shown in Equation 4.6 can be used to describe the opportunity cost of real power loss service.

$$OC_p^{loss}(P) = max(0, \pi_p^{erg}(P), \pi_q(Q)) \tag{4.6}$$

Note that the opportunity cost is always non-negative. This is because when the profit for producing other commodities is less than zero, there is no incentive to produce them, which corresponds to zero alternative capacity usage and zero opportunity cost.

4.3.2.2 Opportunity cost: an example

The market conditions and the cost of production determine the value of opportunity cost. This is illustrated by the following example. Suppose the generator in Figure 4.3 is going to produce $\Delta Q = Q_1$ and it is desired to evaluate the related opportunity cost. There is no other capacity usage except producing real power for sale in energy and loss market. The opportunity cost of ΔQ depends on the profit of $\Delta P = P_{max} - P_1$ in each of the market. Six different cases could occur: these are listed in Table 4.3.

EC_p^{erg}, pr_p^{erg} and π_p^{erg} are the explicit cost, energy market price and the corresponding profit if ΔP is sold in the energy market. EC_p^{loss}, pr_p^{loss} and π_p^{loss} are the explicit cost, loss market price and the corresponding profit if ΔP is sold in the real power loss market. EC_q, OC_q, pr_q, and π_q are the explicit cost, opportunity cost, price and profit for ΔQ.

The opportunity cost of ΔP in both the energy market and the loss market is not considered in the above table. This is because when evaluating the opportunity cost for Q, it has already assumed the reservation of capacity for Q, which means producing P will not happen and, therefore, there is no opportunity cost for P. Equation 4.5 and the following relationship hold for all six cases:

Table 4.3 Six opportunity cost cases

	($)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Energy Market	EC_p^{erg}:	11	11	8	8	8	8
	pr_p^{erg}:	10	10	10	10	10	10
	π_p^{erg}:	-1	-1	2	2	2	2
Loss Market	EC_p^{loss}:	11	11	8	8	8	8
	pr_p^{loss}:	9	9	9	9	9	9
	π_p^{loss}:	-2	-2	1	1	1	1
Reactive Power Market	EC_q:	3	1	1	1	1	1
	OC_q:	0	0	2	2	2	2
	pr_q:	2	2	2	3	5	6
	π_q:	-1	1	-1	0	2	3
Attend energy market?		No	No	Yes	Yes/No	No	No
Attend loss market?		No	No	No	No	No	No
Attend reactive market?		No	Yes	No	No/Yes	Yes	Yes

$$\begin{aligned} \pi_p^{erg} &= pr_p^{erg} - EC_p^{erg} \\ \pi_p^{loss} &= pr_p^{loss} - EC_p^{loss} \\ \pi_q &= pr_q - EC_q - OC_q \end{aligned} \tag{4.7}$$

The six cases use a constant price for the real power sold in energy market ($10) and loss market ($9). Obviously, for the same amount of real power, the explicit cost is the same for both markets, no matter where it will be sold. However, in our example, the price of the loss market is one dollar cheaper than that of the energy market. This makes the opportunity cost of reactive power in loss market is always lower than that in the energy market. In each of the six cases, there is no chance that the real power be sold in loss market. Therefore, the opportunity cost of Q depends completely on the expected profit of unavailable capacity from the energy market.

Compared with the last four cases, the first two cases have higher explicit cost for P, which makes their real power profit in both markets negative and the opportunity cost for Q zero. Case 1 has a high explicit cost for Q so that the net profit for Q is negative. Neither P nor Q will be produced in this case. Case 2 has a low explicit cost for Q and its profit for Q is positive. Therefore, producing Q instead of P is reasonable. Cases 3 to 6 have the same explicit

cost for Q and same net profit for P. However, they involve different prices for Q. In case 3, the low price for Q leads to negative profit for Q. Producing Q therefore is not reasonable. Case 4 has a zero profit for producing Q. However, as the opportunity cost is considered when calculating the profit, it makes no difference in producing P or Q. In case 5, the profit for Q is equal to that for P. In case 6, the profit for Q is higher than that for P. Obviously, Q should be produced in these two last cases.

As seen from the above examples, different opportunity costs lead to different production patterns for P and Q. It also determines the markets in which the generator owner should participate.

4.3.2.3 Evaluation of opportunity cost

Evaluation of the opportunity cost depends on the evaluation of the profit of unavailable capacity. In the practical world, neither the price of P nor Q will be available before hand. The fact that the real/reactive power is bought or sold by matching the bids in the different markets leads to an uncertainty for the profit. Strategic bidding, which was proposed in [19], provides an efficient approach to achieve the maximization of expected profit in the markets.

Since the rational behavior of the market participants was assumed, a seller, who is in the energy market or the loss market, should intend to maximize the following function for each block of energy for sale:

$$\begin{aligned} \underset{pr_s}{Max} \quad E\pi_p &= \text{Prob(bid being accepted)} * \text{lower bound profit} \\ &= [1 - Prob(X \leq pr_s)] * (pr_s - C_p) \end{aligned} \tag{4.8}$$

where, $E\pi_p$ is the expected profit in either the energy market or the loss market, pr_s is the corresponding sell bid, C_p is the explicit cost for this block of real power, and $Prob$ is the probability of other bids price (X) that is lower than pr_s. The first term in Equation 4.8 represents the probability of success of bid pr_s in each market. The second term represents the lower bound of profit if the bid is successful.

Based on this suboptimal bidding strategy, the market participant will select the optimal

pr_s that could maximize the expected lower bound profit $E\pi_p$. This expected profit is the profit for this block of energy Therefore, the opportunity cost of Q is the summation of the maximum expected profit for all the blocks of P that the generator is not able to produce, which is shown in Equation 4.9.

$$\begin{aligned} Opportunity\ Cost &= \sum_j E\pi_p * \Delta P_j \\ &= \int_{P_1}^{P_{max}} E\pi_p \, dP \\ &\qquad when\ \Delta P_j \rightarrow 0 \end{aligned} \tag{4.9}$$

So far, only the evaluation of opportunity cost for reactive support has been discussed. The same procedure can be used to evaluate the opportunity cost of real power loss service. This involves the strategic bidding for the real power sold in the energy and reactive support markets.

4.4 Economic Cost of Transmission Sources

Transmission facilities provide basic transmission services and other services such as reactive support service. These facilities includes transmission lines, transformers, capacitor banks and other parallel or serial compensation devices. In this section, only the cost of reactive support from transmission sources is discussed. This reactive support is not limited to the reactive power provided by the capacitor banks; it also includes the voltage support provided by the transformers. However, it does not incorporate reactive support from the transmission lines themselves, since this automatically occurs whenever the lines are in service.

4.4.1 Explicit Costs

The operating cost for transmission facilities are mainly the maintenance cost, which are often small enough to be ignored. The explicit costs from transmission sources mainly refer to the capital costs of reactive facilities.

Some reactive compensators, such as capacitor banks, are switchable facilities. Because of the mechanical wear during switching, there are only limited number of switching operations

that could be performed during their lifetime. Each switching operation corresponds to a specific capital cost expressed in terms of $/switching operation.

A transformer can also be looked as a "switchable" facility, as only limited number of step changes can be achieved during its lifetime. Its capital cost can be expressed as $/step operation. For each step change that is required, this cost should be considered.

4.4.2 Opportunity Costs

For the installed transmission facilities, there is no alternative usage.[2] They will be either in operation, or not. The opportunity cost in this case is negligible.

4.5 Economic Cost Summary for Reactive Support and Loss Services

In Sections 4.3 and 4.4, the economic cost of generation and transmission sources was analyzed. Table 4.4 summarizes these costs in terms of the two services which are of interest in this work: reactive support service and real power loss service.

Table 4.4 Summary of economic cost for reactive support and loss services

	Explicit Cost		Implicit Cost
	operating cost	capacity cost	Opportunity Cost
Reactive support service from generation sources (ancillary service)	little impact	included	included
Reactive support service from transmission sources	little impact	included	neglibile impact
Real power loss service (interconnected service)	included	included	included

[2]In the real world, there is a necessity of considering short-term overloads versus the decrease in facility life, although they are not included in this research.

4.6 Preparing Bids for Reactive Support and Loss Services

4.6.1 Strategic Bidding in Competitive Markets

The markets for reactive support service from generation sources and real power loss service are assumed to involve incomplete competition. Strategic bidding, which was involved in Section 4.3.2.3 for opportunity cost evaluation, is needed by individual participants for bid preparation.

Based on the economic cost of reactive power, a reactive support service provider will maximize the following expected lower bound profit for each block of reactive power he is going to sell:

$$\begin{aligned} \underset{pr_q}{Max} \quad E\pi_q &= \text{Prob(reactive bid being accepted)} * \text{lower bound profit} \\ &= [1 - Prob(X_q \leq pr_q)] * (pr_q - C_q) \end{aligned} \tag{4.10}$$

where, $E\pi_q$ is the expected economic profit in the reactive service market, pr_q is the corresponding sell bid, C_q is the economic cost for this block of reactive power, and $Prob$ is the probability of other reactive service bid price (X_q) that is lower than pr_q.

Based on the economic cost of real power, a real power loss service provider will maximize the following expected lower bound profit for each block of real power he is going to sell:

$$\begin{aligned} \underset{pr_l}{Max} \quad E\pi_l &= \text{Prob(loss bid being accepted)} * \text{lower bound profit} \\ &= [1 - Prob(X_l \leq pr_l)] * (pr_l - C_l) \end{aligned} \tag{4.11}$$

where, $E\pi_l$ is the expected economic profit in the real power loss market, pr_l is the corresponding sell bid, C_l is the economic cost or this block of loss in real power, and $Prob$ is the probability of other loss bid price (X_l) that is lower than pr_l.

The optimal bids, pr_q and pr_l, will be submitted by the market participants and stored in the service database. The ISO will then identify the services according to the available information.

4.6.2 Cost Recovery for Reactive Support from Transmission Sources

For reactive support service from transmission sources, assuming the transmission system is still a monopoly, there is no existing market for this service so that there is no need to prepare the bids. However, at least full cost recovery is guaranteed.

4.7 Summary

In this chapter, the cost and bid for reactive support service and real power loss service are discussed. Given the bid information, the ISO will simultaneously identify these services based on the overall profit maximization. The detailed service identification for the two services of interest is discussed in Chapter 5.

5 IDENTIFYING REACTIVE SUPPORT AND LOSS SERVICES

In this chapter, the optimization procedure specifically for identifying reactive support and loss services is defined in Section 5.1. The solution algorithms are discussed in Section 5.2.

5.1 Setting up the Optimization Procedure

In previous chapter, the economic cost for reactive support and real power loss services were analyzed. The bid prices, which reflect the economic cost and market conditions, are included in the objective function, whose purpose is to maximize the overall lower bound profit (minimize the cost of congestion plus cost of services) while determining (1) the optimal transaction adjustment, (2) the optimal reactive support service, and (3) the optimal real power loss service.

Considering the specific characteristics of the two services, the general optimization procedure analyzed in chapter 3 can be rewritten as follows:

Min		$\sum_t (pr^a_{b,t} + pr^a_{s,t}) * \Delta P_t$	Cost of congestion
	+	$\sum_g pr_{q,g} * \Delta Q_g$	Cost of reactive power bought from reactive market
	+	$\sum_c C_c * \Delta Q_c$	Economic cost of Q from transmission sources[1]
	+	$\sum_x C_x * \Delta Tap_x$	Economic cost of Q from transmission sources[2]
	+	$\sum_g pr_{l,g} * K_g * \Delta P_l$	Cost of loss bought from loss market

1 full cost recovery for cost of reactive power from capacitors

2 full cost recovery for cost of voltage support from transformers

s.t.	$\overline{P} + \overline{\Delta P} = Re(\overline{V}. * \overline{I}^*)$	(1) Real power flow
	$\overline{Q} + \overline{\Delta Q} = Im(\overline{V}. * \overline{I}^*)$	(2) Reactive power flow
	$\sum_g P_g = \sum_d P_d + P_{loss}$	(3) Real power balance
	$\sum_g Q_g = \sum_d Q_d + Q_{loss}$	(4) Reactive power balance
	$V_{d,min} \leq V_d + \Delta V_d \leq V_{d,max}$	(5) Load voltage constraints
	$S_{ij} + \Delta S_{ij} < S_{ij,max}$	(6) Thermal overload constraints
	$\Delta V_{g,min} \leq \Delta V_g \leq \Delta V_{g,max}$	(7) Generator voltage constraint
	$0 \leq \Delta Q_c \leq Q_{c,max}$	(8) Capacitor capacity constraints
	$\Delta Tap_{x,min} \leq \Delta Tap_x \leq \Delta Tap_{x,max}$	(9) Tap change constraints
	$K_g * \Delta P_l \leq \Delta P^p_{l,g}$	(10) Loss support constraints
	$0 \leq \Delta P_t \leq \Delta P^p_t$	(11) Transaction adjustment constraints
	$0 \leq \Delta Q_g \leq \Delta Q^p_g$	(12) Proposed reactive service constraints

Constraints (1) through (4) are active equalities, which must be satisfied under any circumstances. Constraints (5) and (6) are security constraints, which show the requirement of load voltage and transmission line capacity. Constraints (7) through (12) are dispatchable source constraints.

The control variables for this optimization process are transaction curtailment amount(ΔP_t), generator voltage (ΔV_g), capacitor reactive output (ΔQ_c), amount of tap changing (ΔTap_x) and the loss distribution factor (K_g).

One objective of this optimization procedure is to determine the transaction adjustment. The cost of the curtailment is part of the objective function and the curtailment amount affects other state variables of the system. Therefore, ΔP_t should be one of the control variables.

Although the cost of reactive support from generation sources is evaluated as a function of reactive power output (ΔQ_g), generators' reactive power are, in most cases, dependent variables. The actual levels depend on the system conditions and voltage requirements. The voltages of generators (ΔV_g) are, however, independent and controllable.

Identifying the location and amount of reactive support from transmission sources is another objective of the optimization procedure. The cost of capacitors and transformers are part of

the overall service cost which needs to be minimized. ΔQ_c and ΔTap_x are, therefore, the control variables.

The loss distribution factor K_g represents the percentage of each generator in supplying the system losses. These factors are selected as control variables instead of the individual amount of real output because these generator will act as distributed swing buses. One of the ISO's responsibilities would be to select the distributed swing buses from those who participate in the real power loss market through the bids they submitted.

5.2 Solution Algorithms

5.2.1 Brief Summary of Typical Algorithms

The proposed optimization procedure is, in a broader sense, an optimal power flow, OPF, which was first discussed in 1960s. Economic dispatch is its simplest form. It has evolved to represent any procedure that is meant to minimize or maximize a certain objective function while satisfying the power system constraints. The OPF is a very broad concept and it includes almost everything from power flow to economic dispatch.

The OPF is a large and very difficult mathematical programming problem. Almost all mathematical programming techniques that can be applied have been attempted. The attributes of these methods are summarized next [11].

- Gradient methods [11]

  In gradient methods, a Lagrange function for the OPF is set up. The gradient of this function gives the direction of maximum increase in the objective function as the function of the adjustments in each of the control variables. However, the gradient methods give no indication how far along the gradient direction one should move. Besides that, since the direction of the gradient must be changed quite often, gradient methods are slow in convergence and difficult to solve in the presence of inequality constraints.

- Newton's methods [78]

  Newton's method intends to solve the convergence problem of the gradient method. The derivative of the gradient are taken with respect to state and control variables. However, the handling of inequality constrains is as difficult as that of gradient approach. The usual method is to form a constraint "penalty" function. But when near the limit, the penalty is small, so that the optimal solution will tend to allow the variable to float over the limit.

- Linear programming method [79]

  The linear programming method is one of the fully developed methods now in common use. It can easily handle the inequality constraints. Nonlinear objective functions and constraints are handled by linearization. Other main advantages include the reliability of the optimization and the ability to recognize problem infeasibility.

- Interior point method [80]

  The interior point method did not solve for the optimal solution by following the points that were on the constraint boundary, but followed a path through the interior of the constraints directly toward the optimal solution on the constraint boundary. In this approach, no distinction is made between the state variables and control variables. Slack variables are added which turn the inequalities into equalities. A logarithmic barrier function is added to the objective function so that the nonegativity conditions of slack variables are handled. Then Newton's method or linear programming is used to solve the resultant equations.

Among all the solution algorithms, the linear programming technique is comparatively mature and fast. It was used in this research to solve the proposed reactive support service and loss service identification problem.

5.2.2 Linear Programming

The flowchart for solving the service identification problem by LP is shown in Figure 5.1. It is an iterative procedure since linearization has been used. Comparing with the gradient method and Newton's method, linear programming is very adept at handling inequality constraints, as long as the problem to be solved is such that it can be linearized without loss of accuracy. For the proposed approach, we can linearize the objective function and the non-linear constraints.

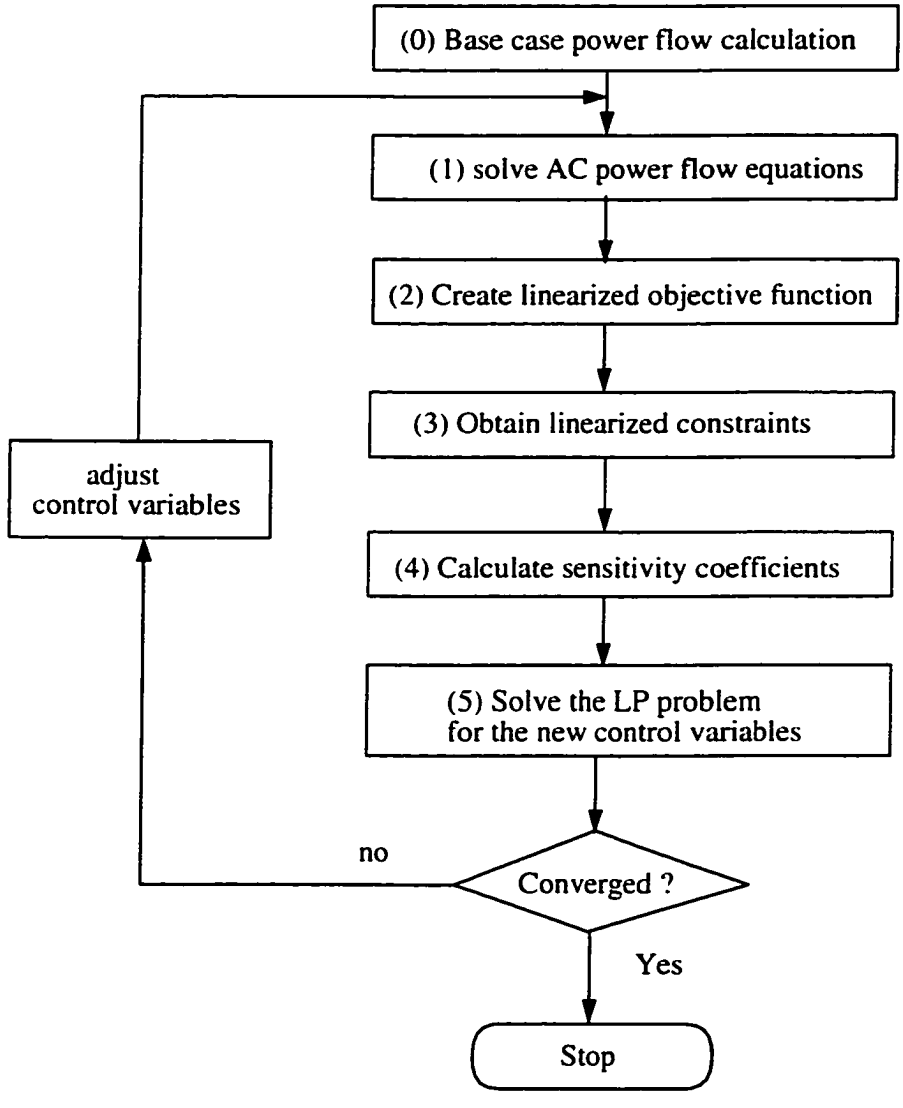


Figure 5.1 Problem solving by linear programming

For the cost coefficients in the objective functions, the cost of congestion for each transaction comes from the bids that are submitted by the energy buyers and energy sellers. Since these bids are already matched by the broker when the ISO is identifying service, these costs are constants.

The cost coefficients for the capacitors and transformers are also constants since a fixed cost will be involved for each operation of these devices. The cost coefficients for the reactive support and real power loss services traded in the markets are generally not constants. Strictly speaking, for each unit of commodity to be sold in the market, there is an optimal bidding price. However, this nonlinear bid price can be approximated by a piecewise linear function as shown in Figure 5.2.

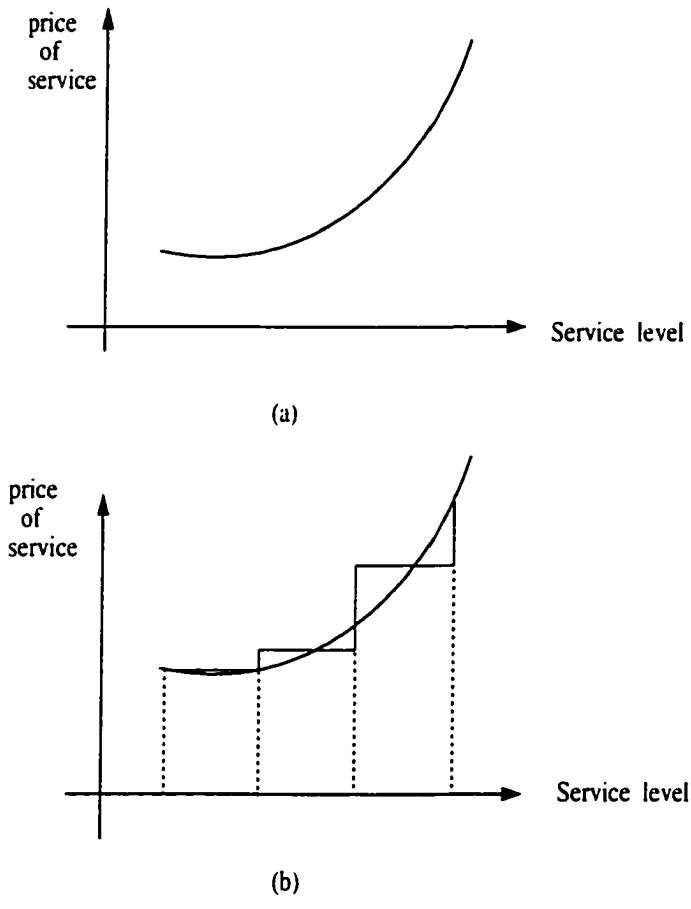


Figure 5.2 Linearize a coefficient of the objective function

Altogether twelve constraints must be satisfied for a feasible solution. The first four are the equality constraints. The solution of power flow in step (1) of Figure 5.1 guarantees their satisfaction. The other eight constraints are inequalities, and all of them are linear.

Control variables like generator voltages and transaction adjustment amounts are continuous variables. Others, like the switching of capacitors and step changes of transformers are discrete variables. The best method to deal with these discrete variables is to use mixed integer programming. However, to make the calculation easier, the switching of a capacitor is transformed into the change of the reactive output, and the step change of a tap-changing transformer is represented by a set of continuous tap ratio changes.

Linear sensitivities are calculated in step (4). These sensitivities give an indication of the change in one system quantity such as real power, reactive power, line flow, bus voltages, etc., when another quantity, especially a control variable, is varied. These linear relationships are essential for the application of linear programming. The inverse Jacobian matrix, which is a by-product of the AC power flow, contains the information related to the sensitivities. A detailed derivation of these sensitivities is provided in Appendix A.

The proposed approach is actually a nonlinear programming problem. Solving it using the linear programming approach is not guaranteed to obtain a global optimal solution. However, as the base case is assumed feasible and the final case is always available (the worst case is final case is exactly the same as the base case), the solution by linear programming is at least a local optimal solution.

6 SERVICE ALLOCATION BY AVERAGE SENSITIVITY METHOD

In the previous chapters, an optimization procedure was defined for the ISO to identify the necessary services of reactive support and real power losses. Since there are costs related to these services, their costs should be allocated fairly to all transmission users. In this chapter, a service allocation algorithm based on the average sensitivity method is developed. This analysis begins with the discussion of the previous allocation methods in Section 6.1. Then, the mathematical derivation and definition of average sensitivity is presented in Section 6.2. Section 6.3 provides the practical application of this method in allocating reactive support and real power loss services.

6.1 Limitation of Previous Allocation Methods

In Chapter 2, several allocation methods were reviewed. They are power flow-based methods, sensitivity-based methods, direct decomposition methods, and various other methods. Each of these methods have their advantages and disadvantages, which are discussed in the remainder of this section.

- Power flow-based methods

  Power flow-based approaches generally provide more accurate results than other methods, although a variation of accuracy does exist between different power flow-based methods. The traditional approaches introduced in [55] and [57] calculate each transaction's contribution serially, so that a different transaction simulation order will affect the allocation results. The aggregated allocation method [58] and average power flow method [59] attempt to overcome this problem and are comparatively more accurate, but take a longer

time. The time requirement for all power flow-based approaches are, at least, proportional to the number of transactions. Therefore, these approaches are time consuming when a large number of transactions is involved. In addition, the convergence of the power flow solution can not be guaranteed under all circumstances.

- Sensitivity-based methods

  Different from power flow-based approaches, sensitivity-based methods generally only require one or two power flow solutions, so that they are quick in providing allocation results. However, the traditional sensitivity-based methods proposed so far [55, 60] fail to cover the total cost. In addition, since the sensitivities are functions of the operating status, the choice of which operating condition to use in between the base case and the final case affects the allocation results.

  The spot price sensitivity methods [63, 64] require an optimal power flow. The results can not guarantee the full cost recovery and the OPF itself is sometimes difficult to solve. Convergence may also be a problem.

- Direct decomposition methods

  Direct decomposition methods are quick approaches. The allocation only depends on one snapshot of a power flow. These methods assumed that all the real and reactive power are the direct results of all transactions. There is no base case or final case.

  The MW-mile method [63, 64, 65] is one of the direct decomposition methods. Its success depends on the method used to decompose the transmission line flow into components of each transaction. One approach, the generalized distribution factor, suggested in [66], is less accurate because of the D.C network model. Another novel topological approach, which was recently proposed [67], traces the the flows from generators to loads. But the allocation is solely based on the generation or load instead of the transaction.

  The current decomposition approaches [70, 71] separated the complex current injection at each bus into the currents of the individual transactions. However, the shunt current injection from transmission lines and compensation devices are ignored, which could be

significant for high voltage systems. In addition, the evenly allocation of the interaction component may lead to inaccuracy since this allocation does not depend on the actual transmission usage.

- other methods

  A fixed tariff was suggested by FERC's NOPR [4], where the fixed tariff ranges from 3% for loss compensation to 1.0 mill per kwh for reactive support, load following and reserve services. Although the allocation would be based on the transaction's actual usage, the given price of 3% for loss and 1.0 mill/kwh for reactive support service would not reflect the true cost.

  Game theory-based approaches [73, 75] emerged recently, however experience with them under various conditions is still insufficient.

As discussed in Section 1.3.2.2, a successful allocation algorithm should have the following characteristics:

- Allocation quantity: the allocation quantity must fully recover the cost of services.
- Allocation ratio: the allocation ratio should reflect fairness, i.e. allocation should be based on the actual usage of the services by the individual transactions.
- Application feasibility: the allocation method should be feasible in practical application, i.e. there should be no convergence problems and the method should require only limited computational time and storage.

Few previous allocation algorithms satisfy all the three requirements. The average sensitivity method, which is derived in next section, is a positive approach towards meeting these requirements.

6.2 Theoretical Foundation of Average Sensitivity Method

Service allocation is to divide the cost of services among simultaneous transactions. Mathematically, this is a procedure to "decompose" a multivariable function (cost of service or service

amount) into a summation of several single variable functions (functions of transactions), as shown in Equation 6.1.

$$F(X_1, X_2, \cdots, X_{nt}) = f_1(X_1) + f_2(X_2) + \cdots + f_{nt}(X_{nt}) \tag{6.1}$$

where, X_t, $t = 1, \cdots, nt$ represent the nt transactions that utilize the system simultaneously. F represents a service, for example, transmission loss service. In this research, the service function F is assumed to be a continuous scalar function so that the service amount to be allocated is the same in regardless of the transaction simulation order.

The illustration begins with a two-transaction example. Then same conclusion can be easily extended to nt transactions. For easy notation, x and y are selected to represent the two transactions in the illustration.

6.2.1 Definition of Average Sensitivity

Assume two transactions, x and y, simultaneously affect the system. They not only change the power injection level from the base case (x_0, y_0) to the final case (x_n, y_n), but also change the value of service from F_0 to F_n.[1]

Traditional sensitivity-based approaches use a linear expression of F as shown in Equation 6.2, where $\Delta x = x_n - x_0$, $\Delta y = y_n - y_0$ and $\Delta F = F_n - F_0$.

$$\Delta F \doteq \frac{\partial F}{\partial x}\Delta x + \frac{\partial F}{\partial y}\Delta y = F_x \Delta x + F_y \Delta y \tag{6.2}$$

Equation 6.2 is accurate only when F is a linear function of x and y.

For high order functions, since the sensitivities $\frac{\partial F}{\partial x}$ and $\frac{\partial F}{\partial y}$ are also functions of x and y, only when Δx and Δy are sufficiently small, will this linear approximation provide accurate results.

Considering the variation of the sensitivities, average sensitivities are defined by Equations 6.3 and 6.4 so that ΔF can be closely approximated by Equation 6.5.

[1] n is a general index representing the number of division between the base case and the final case.

$$AS_x = \frac{\int_{y_0}^{y_n} \frac{\partial F}{\partial x} dy}{\int_{y_0}^{y_n} dy} \tag{6.3}$$

$$AS_y = \frac{\int_{x_0}^{x_n} \frac{\partial F}{\partial y} dx}{\int_{x_0}^{x_n} dx} \tag{6.4}$$

$$\Delta F \doteq \int_{x_0}^{x_n} AS_x(x)dx + \int_{y_0}^{y_n} AS_y(y)dy \tag{6.5}$$

Equation 6.5 is accurate when F is a second order function of x and y.

6.2.2 Derivation of Average Sensitivity

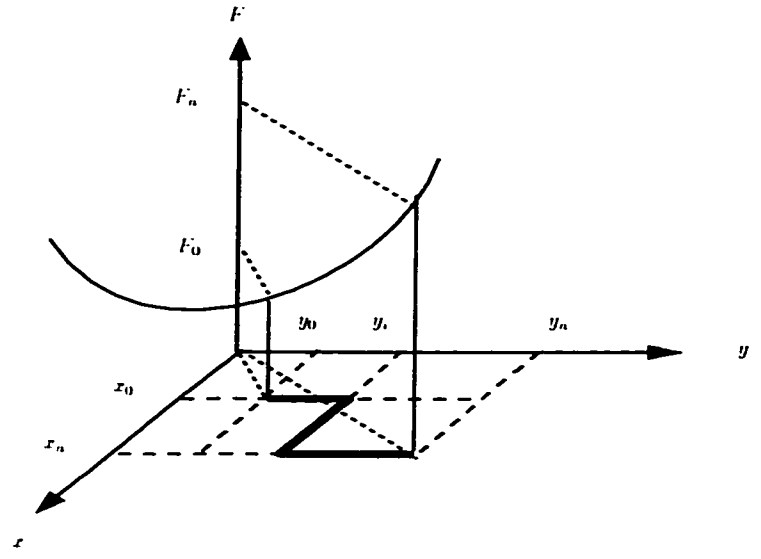
The derivation of the three expressions (Equations 6.3 to 6.5), and the conditions under which they are valued, are illustrated by Figure 6.1.

Since what we are interested in is how ΔF is affected by Δx and Δy, we calculate ΔF by following the path along the axes from (x_0, y_0) to (x_n, y_n). Figure 6.1(a) shows a typical path in three dimensions and Figure 6.1(b) is a two-dimension illustration.

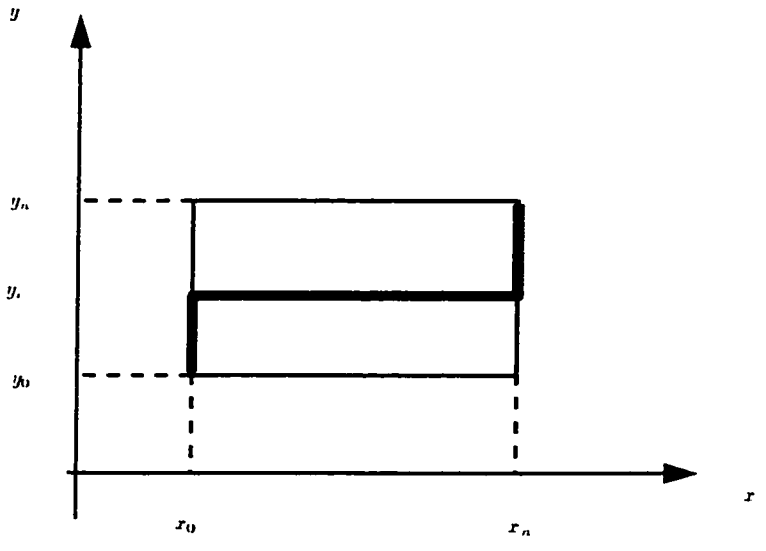
Equation 6.6 gives an expression of ΔF when integrated along a typical path $(x_0, y_0) \rightarrow (x_0, y_i) \rightarrow (x_n, y_i) \rightarrow (x_n, y_n)$, $\forall i = 0, \cdots, n$.

$$\begin{aligned}
\Delta F &= F(x_n, y_i) - F(x_0, y_i) + F(x_0, y_i) - F(x_0, y_0) + F(x_n, y_n) - F(x_n, y_i) \\
&= \int_{x_0}^{x_n} F_x(y_i)dx + \int_{y_0}^{y_i} F_y(x_0)dy + \int_{y_i}^{y_n} F_y(x_n)dy \\
&= \int_{x_0}^{x_n} F_x(y_i)dx + \int_{y_0}^{y_n} \frac{F_y(x_0)+F_y(x_n)}{2}dy + \int_{y_i}^{y_n} \frac{F_y(x_n)-F_y(x_0)}{2}dy - \int_{y_0}^{y_i} \frac{F_y(x_n)-F_y(x_0)}{2}dy
\end{aligned} \tag{6.6}$$

There are $n+1$ similar paths $(y_i, i = 0, \cdots, n)$ between the base case and the final case. So, we have $n+1$ expressions similar to the one shown in Equation 6.6.



(a)



(b)

Figure 6.1 Two transaction illustration

$$
\begin{aligned}
\Delta F &= \int_{x_0}^{x_n} F_x(y_n)dx + \int_{y_0}^{y_n} \frac{F_y(x_0)+F_y(x_n)}{2}dy - \int_{y_0}^{y_n} \frac{F_y(x_n)-F_y(x_0)}{2}dy \\
\Delta F &= \vdots \\
\Delta F &= \int_{x_0}^{x_n} F_x(y_i)dx + \int_{y_0}^{y_n} \frac{F_y(x_0)+F_y(x_n)}{2}dy + (\int_{y_i}^{y_n} \frac{F_y(x_n)-F_y(x_0)}{2}dy - \int_{y_0}^{y_i} \frac{F_y(x_n)-F_y(x_0)}{2}dy) \\
\Delta F &= \vdots \\
\Delta F &= \int_{x_0}^{x_n} F_x(y_0)dx + \int_{y_0}^{y_n} \frac{F_y(x_0)+F_y(x_n)}{2}dy + \int_{y_0}^{y_n} \frac{F_y(x_n)-F_y(x_0)}{2}dy
\end{aligned}
\tag{6.7}
$$

Summing all the expressions and noting that the last term is canceled by a previous like term, we obtain Equation 6.8.

$$
\begin{aligned}
(n+1)\Delta F &= \int_{x_0}^{x_n} (F_x(y_n) + F_x(y_{n-1}) + \cdots + F_x(y_0))dx \\
&\quad + (n+1) \int_{y_0}^{y_n} \tfrac{1}{2}(F_y(x_0) + F_y(x_n))dy
\end{aligned}
\tag{6.8}
$$

Let the distance y_n to y_0 be evenly divided into n parts, so that $dy = \frac{y_n - y_0}{n}$. Therefore,

$$
\Delta F = \int_{x_0}^{x_n} \frac{\sum_{i=0}^{n} F_x(y_i)}{n+1}dx + \int_{y_0}^{y_n} \frac{F_y(x_0) + F_y(x_n)}{2}dy \tag{6.9}
$$

When $n \to \infty$ and $dy \to 0$, Equation 6.9 can be further simplified into Equation 6.10, which provides the true value of ΔF.

$$
\Delta F = \int_{x_0}^{x_n} \frac{\int_{y_0}^{y_n} F_x dy}{\int_{y_0}^{y_n} dy}dx + \int_{y_0}^{y_n} \frac{F_y(x_0) + F_y(x_n)}{2}dy \tag{6.10}
$$

If the second term in the above equation is of the same form as the first term, Equation 6.10 becomes:

$$
\Delta F = \int_{x_0}^{x_n} \frac{\int_{y_0}^{y_n} F_x dy}{\int_{y_0}^{y_n} dy}dx + \int_{y_0}^{y_n} \frac{\int_{x_0}^{x_n} F_y dx}{\int_{x_0}^{x_n} dx}dy \tag{6.11}
$$

which is the exactly the same as Equation 6.5. The terms inside the integration are the average sensitivities according to the definitions provided in Equations 6.3 and 6.4.

6.2.3 Mismatch Analysis

Approximating the true value of ΔF by the average sensitivities includes some error. By comparing Equations 6.5 and 6.10, the mismatch of this approximation can be easily identified as:

$$mismatch = \frac{1}{\Delta x}\int_{y_0}^{y_n}\left(\int_{x_0}^{x_n} F_y dx - \frac{F_y(x_0)+F_y(x_n)}{2}\Delta x\right) dy \tag{6.12}$$

The term in the parenthesis is represented by the shaded area in Figure 6.2, where $\widehat{AB}$ is the sensitivity curve F_y with respect to x.

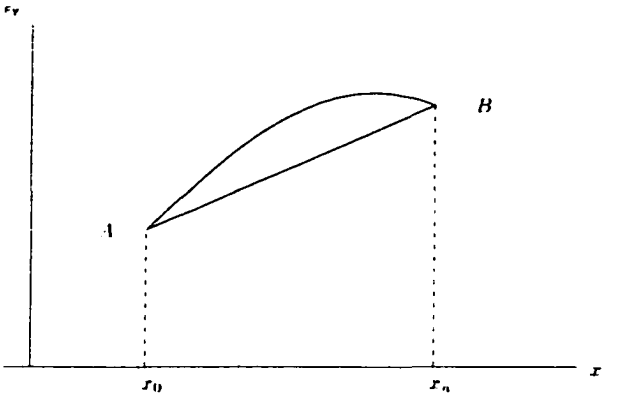


Figure 6.2 Illustration of mismatch

When F is a second order or less function, the sensitivity curve $\widehat{AB}$ is a straight line. There is no mismatch so that it can be concluded that average sensitivity method is accurate for allocating second-order functions.

6.2.4 nt-Transaction Allocation by Average Sensitivities

The same conclusion can be easily extended to nt transaction cases, so that the true value of ΔF can be expressed by:

$$\Delta F \doteq \sum_{i}^{nt}\int AS_i dX_i \tag{6.13}$$

where, the average sensitivities AS_i are defined in Equation 6.14.

$$AS_i(X_i) = \frac{\int \cdots \int F_{X_i}\, dX_1 \cdots dX_{i-1} dX_{i+1} \cdots dX_{nt}}{\int \cdots \int dX_1 \cdots dX_{i-1} dX_{i+1} \cdots dX_{nt}} \tag{6.14}$$

When F is no more than a second-order function, the allocation quantity of each transaction determined by Equation 6.15 can fully recover the true service. The allocation ratio can then be determined by Equation 6.16.

$$f_i = \int AS_i dX_i \tag{6.15}$$

$$Ratio_i = \frac{f_i}{\sum_i f_i} \tag{6.16}$$

The implementation of the average sensitivity method and how to reduce the mismatch is explained in next section.

6.3 Practical Implementation of Average Sensitivity Method

6.3.1 Physical Meaning of Average Sensitivity

As mentioned previously, the traditional sensitivities $\frac{\partial F}{\partial x}$ and $\frac{\partial F}{\partial y}$ are functions of x and y. They could be regarded only as constants if Δx and Δy were small enough. However, when F is a second-order function of x and y, the traditional sensitivities, say, $F_y = \frac{\partial F}{\partial y}$, are linear functions with respect to x or y. All the sensitivities curves are parallel to each other when the system moves from the base case to the final case. This is illustrated by Figure 6.3.

The horizontal axis corresponds to the change in transaction y. The vertical axis represents F_y. When the system moves from the base case (A_0) to the final case (B_1), the sensitivity curves form a set of parallel lines. The bottom line $\overline{A_0B_0}$ is the sensitivity curve when $x = x_0$, and the top line $\overline{A_1B_1}$is the sensitivity curve when $x = x_n$. Points A_0, B_0, B_1, and A_1 constitute a parallelogram.

In the definition of AS_y in Equation 6.4, the numerator is the integration of $\frac{\partial F}{\partial y}$ with respect to all x, and the denominator calculates the amount of x that makes F_y change. Therefore, the division makes the AS_y only a function of y, and the average sensitivity curve lies exactly

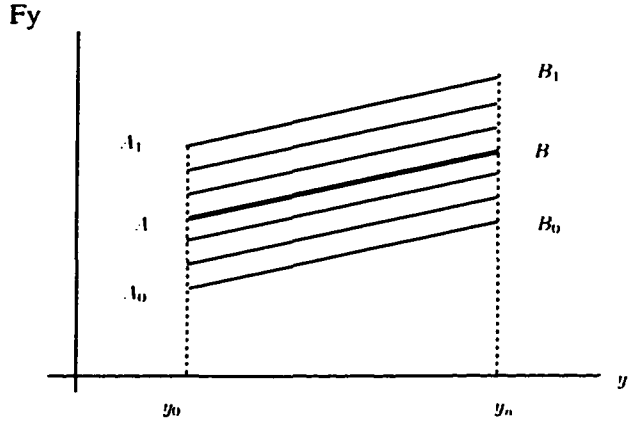


Figure 6.3 Physical meaning of average sensitivity

in the middle of the parallelogram. In Figure 6.3, this average curve is represented by line $\overline{AB}$, the area under which represents the services or costs allocated to transaction y.

6.3.2 Accurate Allocation for 2nd Order Functions

In Section 6.2, it was shown that average sensitivity method has no mismatch in allocating services that are no higher than second-order functions. How to obtain the average sensitivity is the key to this method. A practical implementation does not require the integration as in the definition of average sensitivity. Let's take the previous two transactions as an example.

Assume F is a second-order function with respect to x and y: $F = ax^2 + 2bxy + cy^2$. Therefore,

$$\begin{aligned} F_x &= 2ax + 2by \\ F_y &= 2cy + 2bx \end{aligned} \tag{6.17}$$

According to the definitions in Equation 6.3 and 6.4, the expression of AS_x and AS_y are as follows:

$$\begin{aligned} AS_x &= 2ax + b(y_n + y_0) \\ AS_y &= 2cy + b(x_n + x_0) \end{aligned} \tag{6.18}$$

Because AS_x and AS_y are only functions of x and y, their integration along the individual

axes are easily obtained, so that the allocation quantity of transaction x and transaction y turn out to be:

$$\begin{aligned} f_1 &= (a*(x_0+x_n)+b*(y_0+y_n))\Delta x \\ &= \tfrac{1}{2}(F_x(\text{base case})+F_x(\text{final case}))*\Delta x \\ f_2 &= (b*(x_0+x_n)+c*(y_0+y_n))\Delta y \\ &= \tfrac{1}{2}(F_y(\text{base case})+F_y(\text{final case}))*\Delta y \end{aligned} \tag{6.19}$$

where f_2 equals to the area underneath the line AB in Figure 6.3. A similar expression to Equation 6.19 can be obtained for nt simultaneous transactions.

Practically, using the average sensitivity method to allocate second-order service functions involves only two power flow solutions, a base case and a final case. By averaging the sensitivities in the two cases, the allocation quantity can be easily obtained.

6.3.3 Mismatch Reduction for Higher Order Functions

The average sensitivity method is accurate for allocating second-order functions. For higher order functions, the mismatch can be:

1. reduced by using a piecewise second-order function approximation until the mismatch tolerance is satisfied, and
2. allocated by using the allocation ratio determined in Equation 6.16, so that the allocation quantity expressed by Equation 6.20 is able to completely cover the service.

$$f_i^{true} = Ratio_i * mismatch + f_i \tag{6.20}$$

For higher order service functions, using one average sensitivity curve may produce a large mismatch. However, the higher order functions can be approximated by piecewise second-order functions, so that we can have piecewise sensitivities. The piecewise average sensitivity can produce less mismatch than that of one average sensitivity, as shown in Figure 6.4.

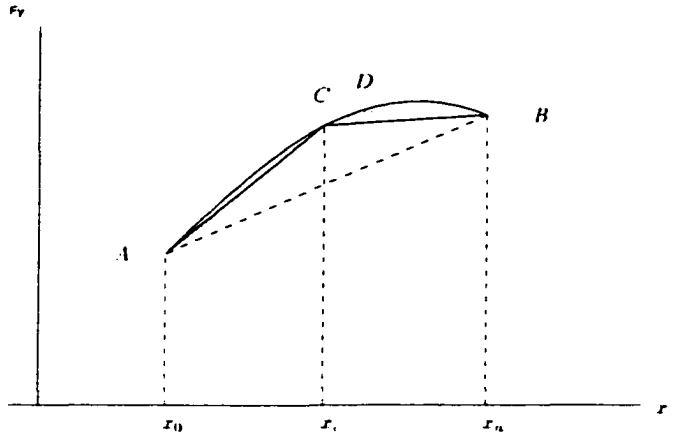


Figure 6.4 Reducing mismatch by piecewise approximation

In Figure 6.4, two lines, $\overline{AC}$ and $\overline{CB}$, are used to approximate $\widehat{AB}$. This produces less shaded area than that in Figure 6.2, where only one line $\overline{AB}$ is used to approximate $\widehat{AB}$.

If the mismatch of two function approximation is still not satisfied, the original function can be further approximated by $4, 8, 16, \cdots$ functions. When this number goes to infinity, it is guaranteed to have zero mismatch and the allocation quantity converges to the true value.

Moreover, a piecewise approximation provides the basis of comparison. Although an infinite number of functions is impossible to reach, the more functions used, the smaller the mismatch is and the closer the allocation quantities will be to the true value.

The selection of the discontinuity point will affect of speed of convergence. The best way is to find a point where non-linearity occurs. For example, in Figure 6.4, selecting point D, instead of point C may produce less mismatch. However, identifying these points would require much effort and different services may require different discontinuity points. For the purpose of practical implementation, subdividing the section with the largest error is a sufficiently good choice.

6.4 Allocating Reactive Support and Loss Services

In Chapter 1, it was suggested that the allocated cost of services be reported back to the market participants so that they could adjust their transactions. However, the allocated costs depend on the allocated services. In this section, the allocation of the reactive support service

and real power loss service using the average sensitivity method is discussed. Both of them can be regarded as second-order functions of transactions under most operating conditions, so that the average sensitivity method can be applied.

6.4.1 Loss Allocation

Whether or not the average sensitivity can be applied for loss allocation depends on the characteristics of transmission losses. Equation 6.21 gives a loss expression.

$$P_l = \sum_{i,j \in line} (V_i^2 + V_j^2)G_{ij} - 2V_iV_j cos\delta_{ij}G_{ij} \tag{6.21}$$

where V_i and V_j are the bus voltage magnitudes at the two ends of line i-j, δ_i and δ_j are the corresponding bus angles. G_{ij} is the line conductance.

The quadratic characteristic of this loss with respect to generator power was recognized early in 1950s [81], where a B-matrix loss formula (Equation 6.22) was used to represent the system loss.

$$P_l = \overline{P}^T B\overline{P} + B_0^T\overline{P} + B_{00} \tag{6.22}$$

However, the difficulty in obtaining the B-matrix prevented the accurate on-line economic dispatch and other applications. In 1970's, a simplified and improved method for calculating transmission loss formula was proposed in [82], where many of the assumptions used in [81] were relaxed and loss coefficients could be easily updated on line to represent actual network conditions. Both references showed that under normal operating conditions (V_i and V_j are constants and close to 1, and δ_{ij} is very small), the transmission loss is approximately a second-order function of the real power inputs.

In this research, it is assumed that a transaction is described by the real power to be transferred. A fixed power factor was assumed if the buyer is a load. Therefore, the transactions can be represented by corresponding real and reactive power injections at the related buses.

When the power factors of transactions are zero, there is no doubt that previous quadratic characteristic still applies to transactions. When the power factors are not zero, the decoupled

power flow gives the expression of voltage magnitudes in terms of power factor and real power injection.

$$\overline{\Delta V} = [B^{''}]\ \overline{\Delta Q} = [B^{''}]\ \overline{K \Delta P} \tag{6.23}$$

Substituting Equation 6.23 into Equation 6.21, the power factors at most will add second-order terms with respect to real power injections.

All in all, the transmission loss is approximately a second-order function of transactions under normal operating conditions, under which the average sensitivity method can be used to allocate loss service without significant errors.

6.4.2 Reactive Support Service Allocation

The reactive service allocation refers to the allocation of reactive support from generation sources. Since this support is one of the six ancillary services that are traded in the service markets, the ISO will allocate the related cost to the various transmission users. Hence, the reactive power output of generation sources will be allocated first into the real power injections.

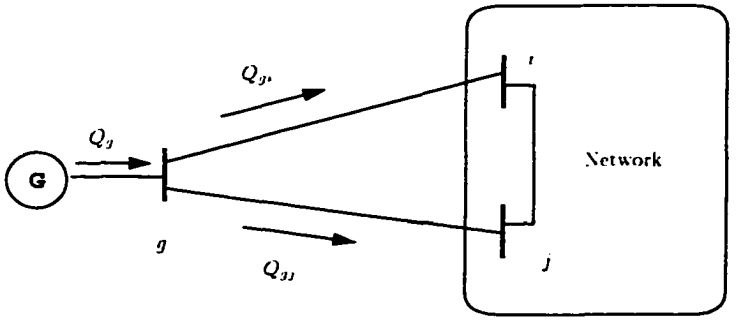


Figure 6.5 Generator reactive power output

For the generator in Figure 6.5, its reactive power output can be expressed as:

$$Q_g = Q_{gi} + Q_{gj} \tag{6.24}$$

in which Q_{gi} is expressed by Equation 6.25 and a similar expression applies to Q_{gj}.

$$\begin{aligned} Q_{gi} &= -V_g V_i G_{gi} sin\delta_{gi} + V_g V_i B_{gi} cos\delta_{gi} - V_g^2 B_{gi} \\ &= C_1 sin\delta_{gi} - C_2 cos\delta_{gi} + C_3 \end{aligned} \tag{6.25}$$

where $C_1 = -V_g V_i G_{gi}$, $C_2 = -V_g V_i B_{gi}$ and $C_3 = -V_g^2 B_{gi}$. G_{gi} and B_{gi} are the conductance and susceptance of line g-i respectively.

Under normal operating conditions, V_i and V_g do not change significantly so that C_1, C_2 and C_3 can be considered as constants. Further by applying the Taylor's expansion to $sin(\delta_{ij})$ and $cos(\delta_{ij})$, Q_{gi} turns out to be:

$$\begin{aligned} Q_{gi} &= C_1 * (\delta_{gi} - \frac{\delta_{gi}^3}{3!} + \cdots) - C_2 * (1 - \frac{\delta_{gi}^2}{2!} + \frac{\delta_{gi}^4}{4!} + \cdots) + C_3 \\ &= C_1 * \delta_{gi} + C_2 * \frac{\delta_{gi}^2}{2!} + C_3 - C_2 + error \end{aligned} \tag{6.26}$$

where $|error| < C_1 * \frac{\delta_{gi}^3}{3!} - C_2 * \frac{\delta_{gi}^4}{4!}$, which is very small when δ_{gi} is small. Applying the approximate linear relationship of the bus voltage angles with the real power injection (Equation 6.27), Q_{gi} turns out to be an approximate second-order function of real power injection as shown in Equation 6.28.

$$\overline{\delta} = [B'] \, \overline{P} \tag{6.27}$$

$$Q_{gi} = C_1 * \sum_t (B'_{gk} - B'_{ik}) P_k + \frac{C_2}{2} (\sum_k (B'_{gk} - B'_{ik}) P_k)^2 + C_3 - C_2 \tag{6.28}$$

where B'_{gk} and B'_{ik} are elements in matrix $[B']$.

Similarly, the same expression applies to Q_{gj}. Therefore, the generator output which is the summation of Q_{gi} and Q_{gj} can be approximated by a quadratic function of real power.

When the power factors of the transactions are zero, there is no doubt that previous second-order characteristic of reactive power still applies to transactions. The average sensitivity method can be used to allocate the reactive services from generator sources. When the power factors are not zero, higher-order terms may appear in the reactive power expression. If the high-order terms are significant, a piecewise average sensitivity method should be used.

6.4.3 Service Allocation Flowchart

The service allocation by the average sensitivity method is summarized in Figure 6.6. One thing to note is that when the number of approximation functions are increased, all previous power flow cases will become either the base case or the final case for the new functions. Therefore, only a few additional power flows need to be performed.

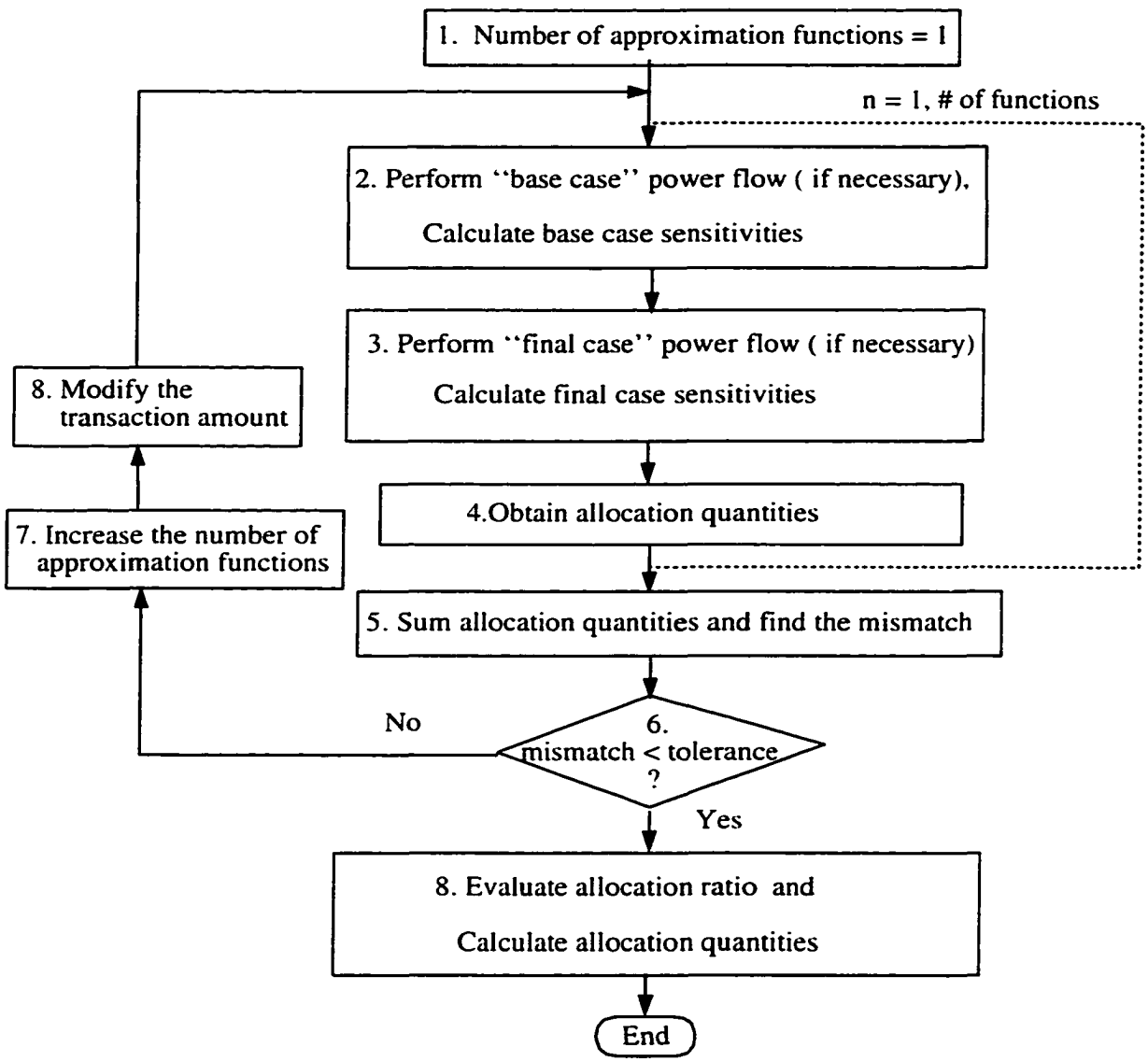


Figure 6.6 Service allocation flowchart

6.5 Summary

In this chapter, the average sensitivity method for service allocation is discussed. This method is advantageous over previous methods in that it can give precise allocation results for second-order service functions. For higher order functions, a revised piecewise average sensitivity method can also be applied. Practical implementation does not require complicated integration as in the definition of average sensitivity, and only a few power flow solution are needed. The test results of the average sensitivity method, together with the test results of service identification are provided in next chapter.

7 TEST RESULTS AND ANALYSIS

In this chapter, the test results and analysis are provided. Section 7.1 gives a brief overview of the test system. Section 7.2 provides the results and analysis for costs and prices of the two services. Section 7.3 and 7.4 are results and discussion related to the service identification and service allocation.

7.1 Overview of the Test System

The test system used in this work is the IEEE standard 30-bus system. Its system configuration is shown in Figure 7.1.

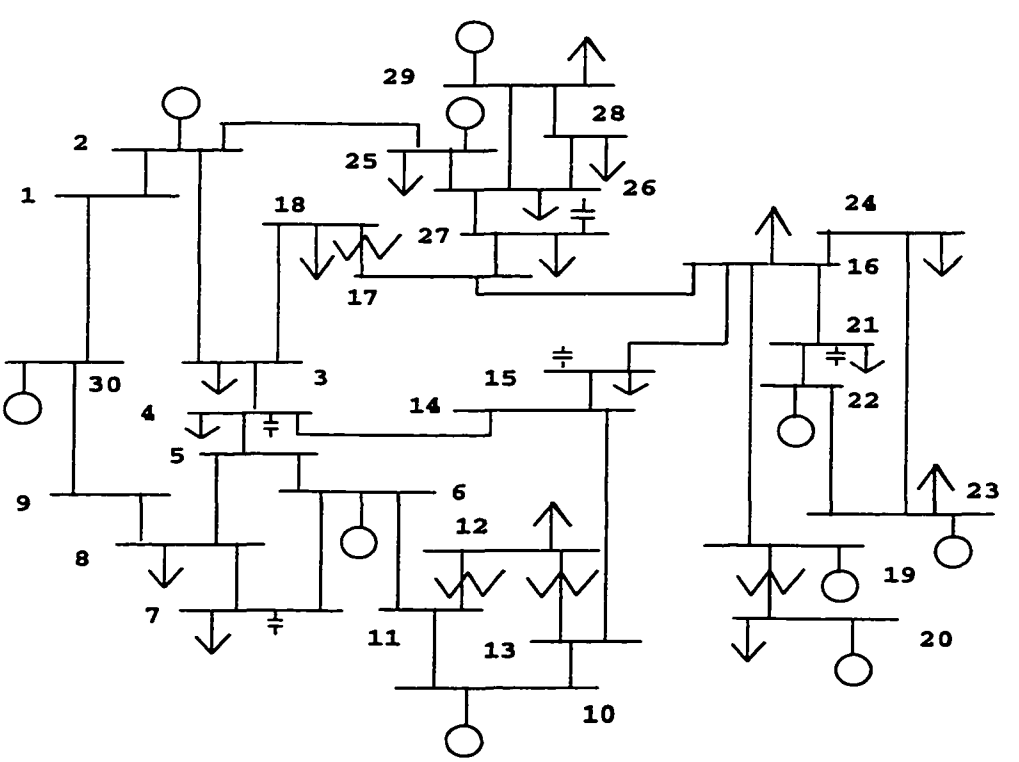


Figure 7.1 One-line diagram of 30-bus system

There are ten generators in the system. All of them are assumed to be thermal units. There are four transformers and two of them (the ones that connect buses $11-12$ and $12-13$) are tap-changing transformers. Five capacitor banks locate at bus 5, 7, 15, 17, and 21. The cost data for these generators, transformers, and capacitor banks is listed in Appendix B.

Each generator owner and each load owner are assumed to be independent market participants. They determine the bids for each market according to individual generator/load conditions and various market conditions.

At the base case (already optimal), the overall generation of the system is $6339.2MW$. The overall load level is $6150MW$ and the system loss is $189.2MW$, which is 2.99% of the total generation.

7.2 Cost and Price for the Two Services

7.2.1 Economic Cost of Services from a Generation Source

In this section, the test results of economic cost from a generation source are analyzed. The generator located at Bus 2 was selected as an example. The data that is available to calculate each component of its economic cost is listed in Table 7.1.

Table 7.1 Typical data for the generator at Bus 2

Maximum real power output (P_{max})	350 MW
Minimum real power output (P_{min})	100 MW
Maximum reactive power output (Q_{max})	350 MVar (lagging)
Minimum reactive power output (Q_{min})	-100 MVar (leading)
Installed cost (IV)	800.000 \$/MW
Expected life (yr)	30 year
Availability factor (af)	85%
Load factor (lf)	64%
Power factor (pf)	0.9
Minimum fuel marginal cost (MC_{min})	7.92 \$/MW
Maximum fuel marginal cost (MC_{max})	9.68 \$/MW

Figure 7.2 shows the simplified capability diagram of this generator. Since the minimum real power is $100MW$ instead of $0MW$, the actual maximum and minimum reactive power output are $Q_{mx} = 335.4MVar$ and $Q_{mn} = -95.8MVar$, which are different from the theoretical values (Q_{max} and Q_{min}) listed in Table 7.1.

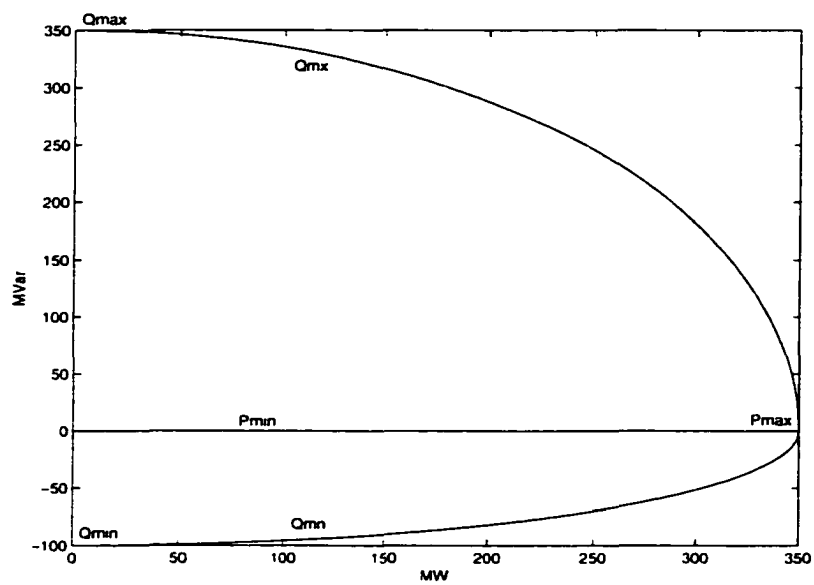


Figure 7.2 Simplified capability diagram for the generator at Bus 2

7.2.1.1 Explicit Cost Calculation

Generally, the ISO determines the system operation schedule on an hourly basis, the explict cost, which includes the operating cost and capacity cost, should also be determined on an hourly basis.

Operating Cost

Since the information for a maintenance cost is unavailable , in this example, the generator's operating cost for real power production is composed only of fuel cost. A quadratic fuel cost function was assumed. Given the minimum marginal and maximum marginal costs, the marginal cost function would be:

$$MC_{fuel} = \frac{dC_{fuel}}{dP} = 0.00704 * P + 7.216$$

So that, the actual cost function is:

$$C_{fuel} = 0.00352 * P^2 + 7.216 * P + constant \tag{7.1}$$

where the *constant* is determined by comparing the actual fuel usage at a constant power output for a specified time to the value computed using Equation 7.1.

This operating cost is only applicable to energy in the form of real power and the real power loss service, since the two require fuel for real power production. On the other hand, a fuel cost is not included in the cost of reactive support service.

Capacity Cost

As the cost is needed on an hourly basis, the installed capacity cost should be converted into the capital cost per operating hour (\$/MW per hour). The following equation shows such a conversion, given the available information.

$$\$/MW\ per\ hour = \frac{IV * P_{max}}{P_{max} * af * lf * 8760 * yr} = \frac{IV}{af * lf * 8760 * yr} \tag{7.2}$$

For the generator whose data is listed in table 7.1, its capital cost per hour is $\$5.60/MW$. When the generator is operating at its nominal power factor, the capacity cost in terms of MVA is $\$5.04/MVA$, in terms of real power is $\$4.53/MW$, and in terms of reactive power is $\$2.20/MVar$. Here, the $\$4.53/MW$ is one component of the capital cost investment that should be recovered by the real power. It is different from the results of the traditional calculation which is $\$5.60/MW$, where capital cost is only covered by the real power.

Given the operating and capacity costs of this generator, its explicit costs for real power loss and reactive support service are shown in Equations 7.3 and 7.4.

$$EC(P_l) = (4.53 * P_l) + (0.00352 * P_l^2 + 7.216 * P_l + Constant) \tag{7.3}$$

$$EC(Q) = 2.20 * |Q| \tag{7.4}$$

The first term in Equation 7.3 represents the capital cost while the later term represents the operating cost. The reactive support cost, as shown in Equation 7.4 involves only a capital cost.

7.2.1.2 Opportunity Cost Evaluation

In this section, the calculation of the opportunity cost of reactive support and real power loss service is illustrated. Three incomplete beta distributions were selected[1] to represent the respective market-price distributions. Their shape parameters are listed in Table 7.2[2] and the associated probability and cumulative density functions are shown in Figure 7.3 and 7.4.

Table 7.2 Shape parameters of market price distributions

	α	β	Maximum bid price M
Energy market	5	5	$\$25/MW$
Loss market	10	10	$\$26/MW$
Reactive market	5	5	$\$3.2/MVar$

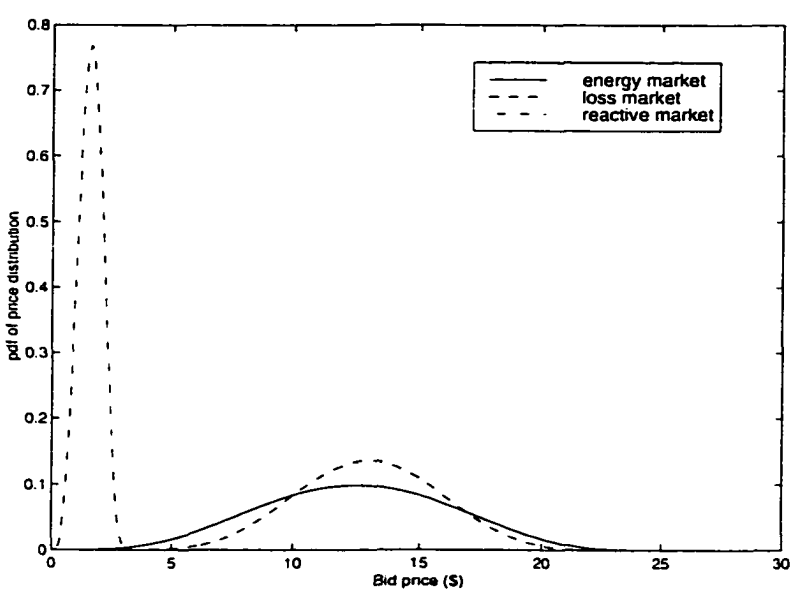


Figure 7.3 Probability density function of price in the three markets

Given the market-price distribution and the explicit cost of real and reactive power, the opportunity cost of reactive power is shown in Figure 7.5. In this figure, the solid line is the overall opportunity cost. The dash dotted line (covered by the solid line) represents the profit of unavailable real power if the real power is sold in energy market and the dashed line

[1]This distribution is recommended in [9]. Its expression is defined as $B(\alpha,\beta) = \int_0^1 t^{\alpha-1}(1-t)^{\beta-1}dt$.

[2]Practically, the market distributions come from the expectation of individual participants. In this example, it is the owner of this generator. Different individuals may have totally different distributions.

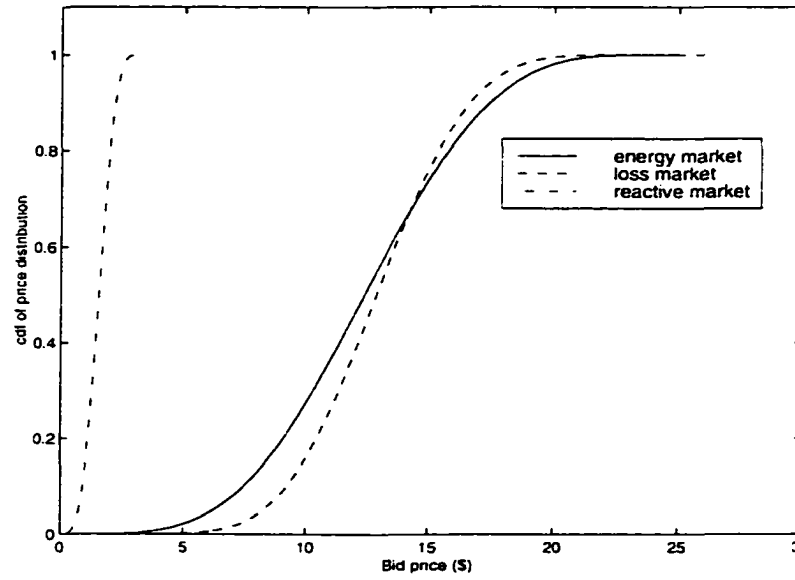


Figure 7.4 Cumulative density function of price in the three markets

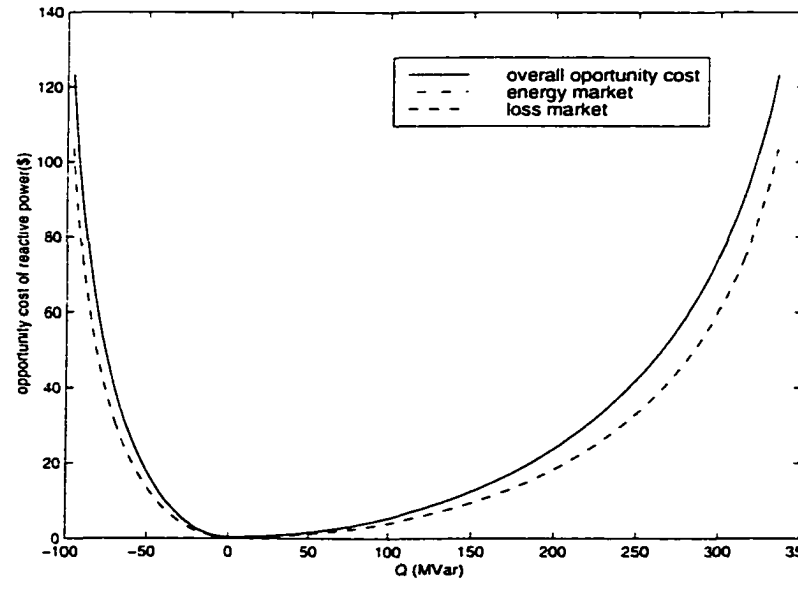


Figure 7.5 Opportunity cost of reactive power

corresponds to the profit of unavailable real power if it is sold in the real power loss market.

For this generator, its marginal cost of real power production is between \$12.5 and \$14.5. This makes its optimal bids in both the energy and loss market greater than \$15, which is to the right of the dotted line in Figure 7.4. For the same bid price greater than \$15, the probability of winning in the energy market is greater than that in the loss market. This results in the higher expected profit in the energy market. As the opportunity cost is the value of something in its next best employment, the overall reactive support opportunity cost (solid line in Figure 7.5) should be exactly the same as the unavailable profit in the energy market.

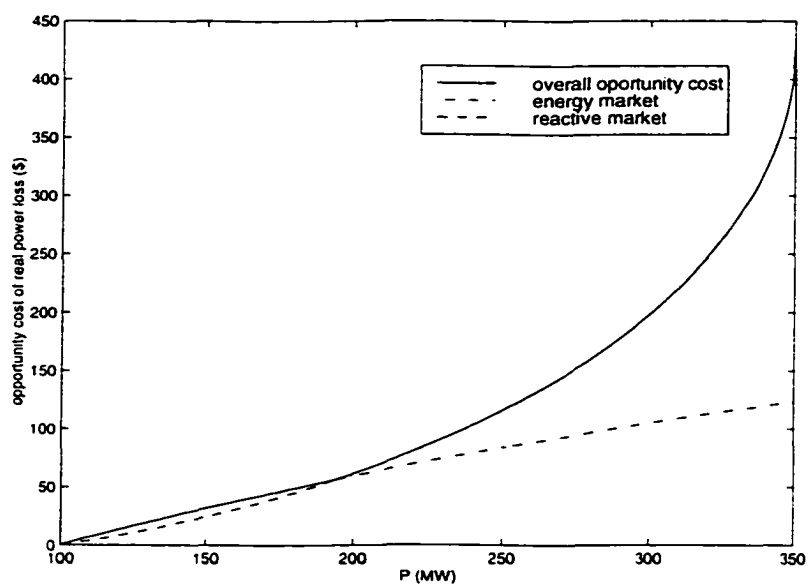


Figure 7.6 Opportunity cost of real power loss

In Figure 7.5, the reactive power for both the leading and lagging power factor cases have opportunity costs because they both occupy the capacity that could be used to produce real power. For the same value of reactive power, the opportunity cost of Q in the leading power factor is much higher than that of the Q in lagging power factor. This corresponds to the more restricitive operating constraints that a generator suffers while operating at a leading power factor.

Similarly, the opportunity cost of real power loss was calculated and is shown in Figure 7.6. The overall opportunity cost of loss is composed of two parts. When the real power production

for loss service is less than $194MW$, the unavailable profit in energy market is higher than in the reactive support service market. When the loss to be sold is more than $194MW$, the opposite is true. The opportunity cost of loss will always be the highest value of the two markets' unavailable profits.

7.2.1.3 Economic Cost of Reactive Support and Loss Services

Given the explict and opportunity cost of reactive support and real power loss services, their total economic costs are shown in Figures 7.7 and 7.8. The economic cost for reactive power is the summation of the explict cost in Equation 7.4 and the opportunity cost in Figure 7.5. The economic cost for real power loss is the summation of the explict cost in Equation 7.3 (with assumed $constant = 0$) and the opportunity cost in Figure 7.6.

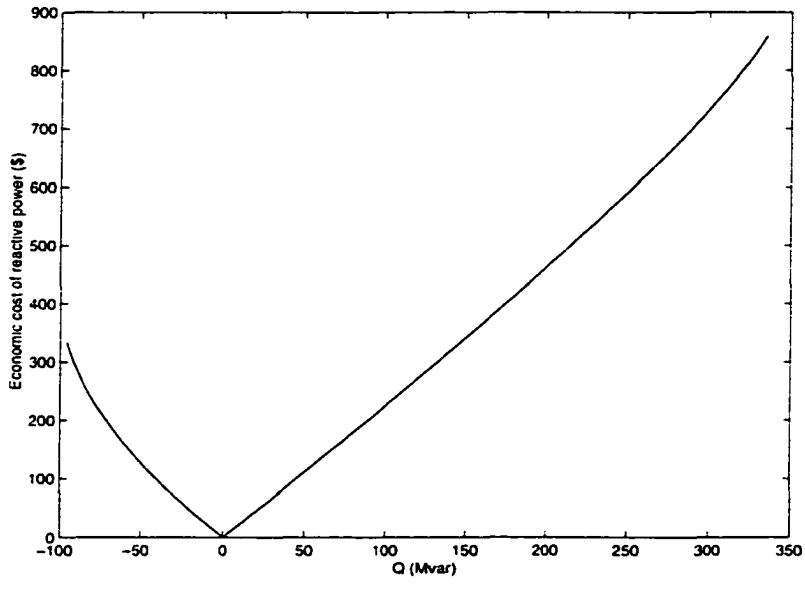


Figure 7.7 Economic cost of reactive power

7.2.2 Economic Cost from Transmission Sources

7.2.2.1 Explicit cost of a Capacitor

For the 69 KV capacitor bank located at bus 5, its installation cost is $\$11600/MVar$. It can be switched 28616 total times (=2 switching operations/day x 365 days/yr x 40 years

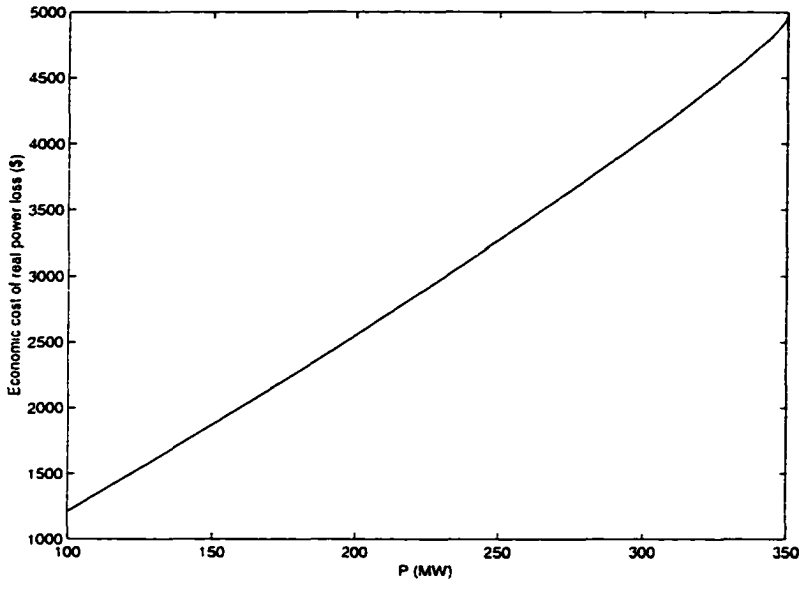


Figure 7.8 Economic cost of real power loss

x 0.98 availability factor). So, the depreciation cost is 0.41 $/switching operation/MVar (=$11600/28616). If the capacity of this capacitor is 50 MVar, then each switching operation will cost $20.5 (=$0.41 x 50).

7.2.2.2 Transformers

For the 161/69 KV, 50 MVA transformer located between buses 11 and 12, its installation cost is $1x10^6 (= $20000/$MVA$ x 50MVA). Its tap can be adjusted 157388 times during its lifetime (=11 steps/day x 365 days/yr x 40 years x 0.98 availability factor). Therefore, each step change is worth $6.35 depreciation cost. If each step change corresponds to a 5/8% tap ratio change, then, there will be a explicit cost of $10.16/1%tap ratio (=$6.35/0.625).

7.2.3 Preparing Bids for the Two Markets

The energy or services are generally traded in the markets in terms of blocks. Different markets have different minimum block sizes. Since different block sizes will affect the average cost for a block of this commodity, which in turn will affect the bid prices; in this example, a per unit block size (one MW or one $MVar$) was assumed.

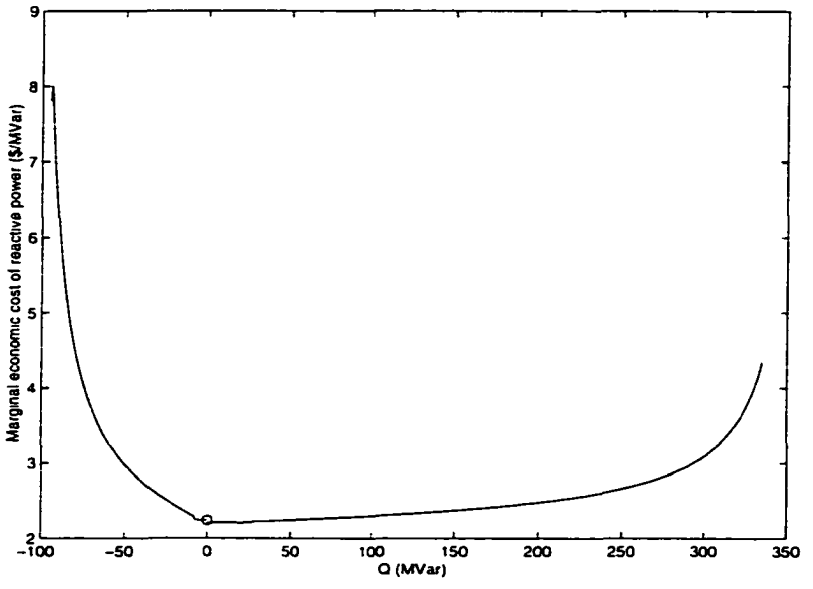


Figure 7.9 Marginal economic cost of reactive power

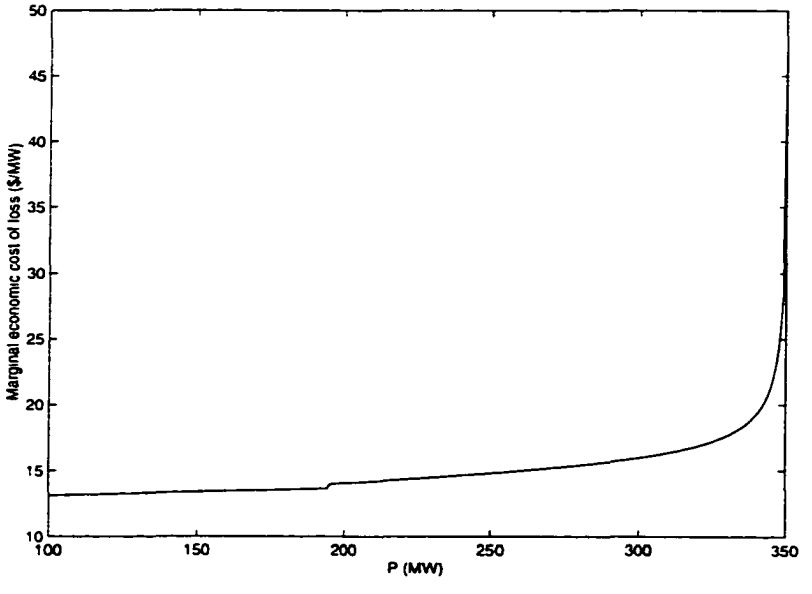


Figure 7.10 Marginal economic cost of real power loss

Given the total economic cost curve, the average economic cost (marginal cost for the per unit block size) for each of the two services are shown in Figures 7.9 and 7.10. The corresponding optimal bid prices are shown in Figures 7.11 and 7.12.

Strictly speaking, in Figure 7.9, there does not exist a first order derivative when $Q = 0$. However, the marginal economic cost at 0+ and 0− can still be calculated. For the marginal economic cost of real power loss, there is a discontinuity point. This corresponds to the discontinuity at $P = 194MW$ in the opportunity cost curve.

For this example, since the highest bid price in reactive support market is $\$3.2/MVar$, the reactive power prices are generally within this level and not high. But there is a range where $Q \geq 340MVar$ or $Q \leq -50MVar$, where marginal economic cost already exceeds the maximum market price. In this range, it is not profitable to participate in the reactive support market. The profitable output range of reactive support is bounded by the two straight lines shown in Figure 7.11.

For the real power loss bids, the discontinuity bid price corresponds to the discontinuity opportunity cost. In some range ($P_l \geq 348MW$), where the marginal economic loss cost exceeds the maximum market price, it is not economically profitable for this generator to participate in the loss market.

Because the analytical expression for the economic costs and their associated marginal costs are difficult to obtain, the optimal bid prices are found numerically. This makes the bid price curve unsmooth.

7.3 Service Identification

The economic cost and bid price analysis provides the market participants the methods to evaluate their economic costs and to prepare the bids which could maximize their lower bound of economic profit. The ISO will select necessary services from the bids submitted. In this section, examples on service identification and congestion management are discussed.

Assume three transactions are submitted to the ISO and are going to be in effect simultaneously in the near future. Their location and amount are listed in Table 7.3.

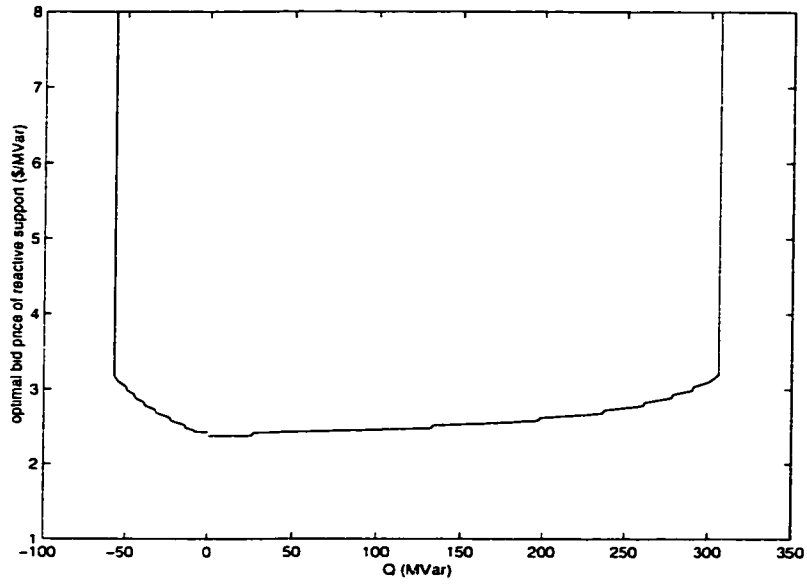


Figure 7.11 Optimal bid for reactive support service

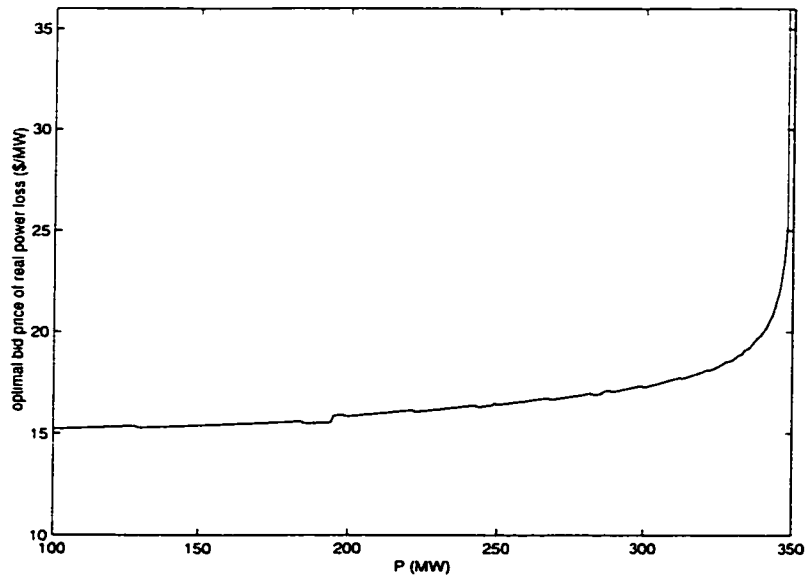


Figure 7.12 Optimal bid for real power loss service

Table 7.3 List of three transactions for service identification

	Energy seller	Energy buyer	MW amount	MVar amount
Trans1	Bus 30	Bus 21	200	30
Trans2	Bus 2	Bus 7	50	0
Trans3	Bus 23	Bus 3	150	20

Assume all generators participate in the reactive support and real power loss service markets. Their bid prices for each unit of service are obtained through the same procedure described in Section 7.2.1.

Two cases are discussed in the following sections. In the first case (Section 7.3.1), the three transactions do not cause any violation of operation constraints. The ISO will only identify the necessary reactive support and real power loss services. In the other case (Section 7.3.2), the three transactions create some violations. The ISO will manage congestion while simultaneously identifying the necessary services for the curtailed transactions.

7.3.1 Case 1: No Congestion

Since there is no violation for the proposed transactions, the optimization procedure was set up to identify the reactive support and real power loss service with the upper bound service cost minimized (lower bound profit maximized). This procedure was solved by the linear programming technique. The cost of services with respect to solution iterations is shown in Figure 7.13.

Linear programming leads to a significant cost reduction during the first several iterations. Its speed of convergence slows down gradually and it converges after 20 iterations within the tolerance of less than $20. The overall behavior is not ideal for a small tolerance value. This is because of the linear approximizations in both the objective function and the control variables.

The resultant service levels and their costs for each market participant before (iteration 0) and after the optimization (28th iteration) are listed in Table 7.4.

When the three transactions are added to the system, the level of loss and/or reactive support services may be lower than the base case for individual market participant, such as Gen 10. But in general, more services are needed to support the three transactions.

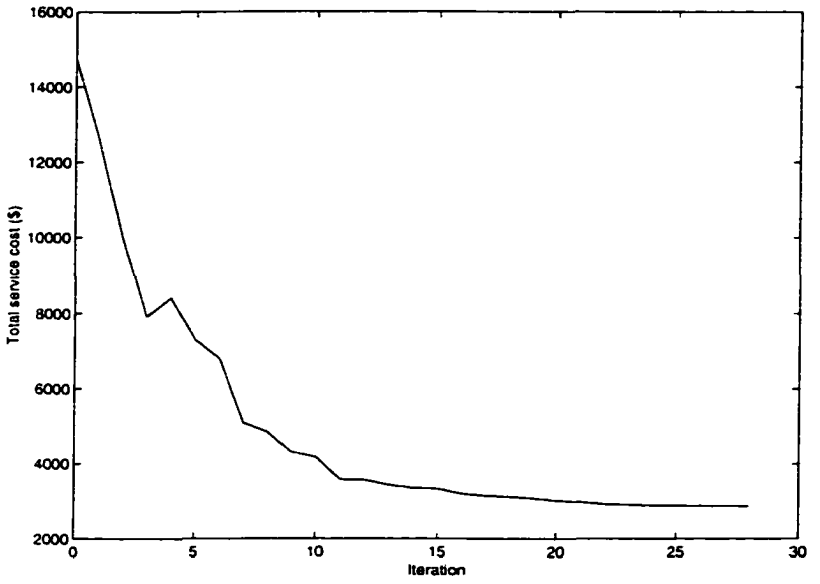


Figure 7.13 Service identification solved by LP

The overall loss service required was 23.51MW before the optimization and 25.06MW afterwards. Although optimization does not lower the amount of losses in this case, it does reduce the cost of losses. Since the proposed approach allows the ISO to select appropriate amount of services from both tansmission and generation sources, the comparatively cheaper generators, Gen 1 and Gen 2, become the major supporters of transmission losses. The optimization also brings a significant reduction of total reactive support services both in quantity and cost.

Although for the three transactions, the total costs are reduced after the optimization, the security constraints are still satisfied with no thermal load or voltage violations (Figure 7.14).

Two other approaches were also used to identify the reactive support and real power loss services. Their objective functions, control variables, the resultant total services and their costs are listed in Table 7.5.

Approach I is based on the the methodology provided in Reference [23] where a series of cost minimizations were provided to identify individual services. It minimized the cost of reactive support service and the resultant cost is $2197.8, which is the lowest among the three approaches. However, since this approach seperates the loss market from the reactive support

Table 7.4 Results of service identification

	Before optimization					After optimization				
	Loss service		Reactive service		Total	Loss service		Reactive service		Total
Gen	MW	$	MVar	$	$	MW	$	MVar	$	$
1	2.2	53.0	30.5	73.0	126.0	5.7	117.8	165.8	407.7	525.5
2	10.7	171.0	31.4	2071.0	2242.0	52.9	879.1	2.7	8.4	887.5
3	0.0	0.0	21.7	66.0	66.0	0.0	0.0	2.0	6.0	6.0
4	0.0	0.0	28.9	1038.0	1038.0	0.0	0.0	11.5	34.8	348.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.3	53.5	53.5
6	0.0	0.0	105.6	10442.0	10442.0	0.0	0.0	12.5	1220.1	1220.1
7	0.0	0.0	13.6	878.0	878.0	0.0	0.0	7.6	290.7	290.7
8	0.0	0.0	45.1	111.0	111.0	0.0	0.0	-84.9	177.3	177.3
9	0.0	0.0	11.8	26.0	26.0	0.0	0.0	-9.0	-19.6	-19.6
10	10.7	4909.0	-9.6	19.0	4928.0	-33.6	-499.4	-55.3	112.7	-386.7
Sum	23.5	5133.0	278.9	14742.0	19875.0	25.1	497.5	70.3	2291.6	2789.1

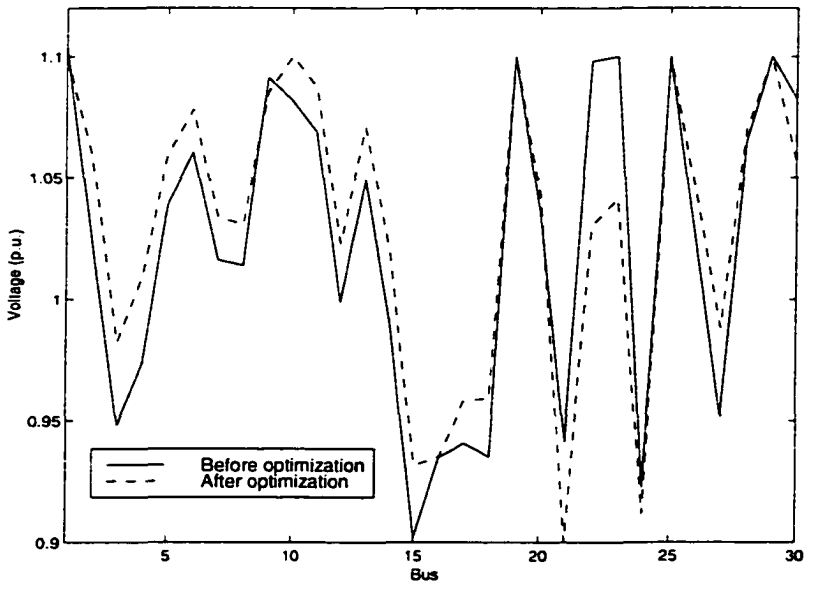


Figure 7.14 Voltage levels before and after cost minimization

Table 7.5 Comparison of service identification among three approaches

	Overall optimization	Approach I	Approach II
Objective function	minimize total service cost	minimize reactive cost	minimize loss cost
Control variables	V_g, ΔTap ΔQ_c, K_g	V_g, ΔTap ΔQ_c	V_g, ΔTap ΔQ_c
Loss Service (MW)	25.06	28.13	10.00
Reactive Service (MVar)	70.29	79.96	-37.77
Cost of loss service ($)	497.5	7266.6	419.3
Cost of reactive support ($)	2291.5	2197.8	13434
Cost from trans. sources ($)	83.1	282.3	152.5
Total service cost ($)	2872.1	4313.4	14006.0

market, the cost of losses becomes very high.

Approach II is the traditional approach for reactive power dispatch [31, 32], where the cost of losses is minimized. The resultant transmission loss is $10MW$ and the cost is $419.3, which are the lowest among the three methods. But, this lower level of losses is achieved through the reactive support, which is quite expensive compared with two other approaches (some generators were working in lead).

As seen from Table 7.5, the proposed cost minimization achieves the lowest overall service cost, among which, the cost from transmission sources is only a small amount and the cost of losses and reactive support are the major components.

7.3.2 Case 2: Congestion Management and Service Identification

A more restrictive set of thermal limits for transmission lines was assumed in this case, so that the proposed transactions cause an overload of two transmission lines. The overloaded lines and their flows are listed in Table 7.6.

Table 7.6 Flow in two overload lines

	line flow (MVA)	thermal limit (MVA)
Line 2-3	519.5	500
Line 21-22	706.7	620

Two optimization approaches were set up to identify services and transaction curtailment. The first approach is the proposed cost minimization (profit maximization) approach where the overall congestion cost and service cost are minimized. The second approach [24] only minimizes congestion cost. The per unit congestion cost for each transaction is $\$40/MW$, $\$20/MW$ and $\$30/MW$ respectively. The resultant curtailment amount, curtailment cost, service costs, total cost and the flow for the original overload lines are listed in Table 7.7.

Table 7.7 Comparison of results when there is congestion

Objective function		minimize overall cost	minimize congestion cost
Control variables		ΔP, V_g, ΔTap ΔQ_c, K_g	ΔP
Curtailment	Trans1	0	$90.19MW$
	Trans2	0	0
	Trans3	$144.5MW$	$145.89MW$
Cost	congestion	\$4335.8	\$7984.5
	loss service	-\$37.5	\$42.3
	reactive support	-\$282.9	\$740.1
	trans. sources	\$83.9	0
	total	\$4099.3	\$8766.9
Line flow	line 2-3	$462.63MVA$	$450.45MVA$
	line 21-22	$620MVA$	$620MVA$

Both the two approaches reduced the flows in the overload lines. They fully used the line capacity as the flow of one line (line 21-22) has just reached its thermal limit. This reduction of line flows was the result of transaction curtailment, as well as reactive support and real power loss services. However, the second approach in [24] resulted in a larger amount of transaction adjustment compared to the proposed approach discussed in this dissertation. Since ΔP was the only control variable, it failed to utilize the reactive support sources, which sometimes could have a significant effect on the line flows.

The curtailment amount and their costs also depend on the comparative cost of congestion with respect to the service costs. In the above example, the per unit congestion cost for each transaction was selected to be $\$40/MW$, $\$20/MW$ and $\$30/MW$ respectively. These amounts are decreased proportionally to $\$12/MW$, $\$6/MW$ and $\$9/MW$, or increased proportionally to $\$160/MW$, $\$80/MW$ and $\$120/MW$, to represent the comparative cost of congestion. In

extremity, the cost of services is not considered when the minimum curtailment is achieved. This corresponds to the case with an extremely expensive cost of congestion. The results of service identification and transaction curtailment under different congestion costs are listed in Table 7.8.

Table 7.8 Different results for different congestion costs

		in-expensive	in-between	expensive	extremely expensive
Per unit congestion cost	Trans1	\$12/MW	\$40/MW	\$160/MW	∞
	Trans2	\$6/MW	\$20/MW	\$80/MW	∞
	Trans3	\$9/MW	\$30/MW	\$120/MW	∞
Curtailment amount	Trans1	0MW	0	0MW	0MW
	Trans2	0MW	0	0	0MW
	Trans3	150MW	144.5MW	139.08MW	125MW
Cost	congestion	\$1350.0	\$4335.8	\$16689.0	∞
	loss service	-\$116.0	-\$37.5	\$32.1	\$365
	reactive support	-\$351.3	-\$282.9	-\$170.8	\$37811
	trans. sources	\$78.7	\$83.9	\$128.9	\$280.9
	total	\$961.4	\$4099.3	\$16679.0	∞
Line flow	line 2-3	464.88MVA	462.63MVA	465.29MVA	458.43MVA
	line 21-22	620MVA	620MVA	620MVA	620MVA

When the per unit congestion cost is comparatively inexpensive, more transactions are curtailed and less reactive support and loss services are required. When the per unit congestion cost is comparatively expensive, there is less curtailment and more services are required. A tendency can be observed that, with the increase of curtailment cost, the system will utilize more of its sources of reactive and loss support. If the cost of congestion goes to infinity, the cost of reactive support and losses is not the major concern when the ISO makes its decision. All the appropriate service sources were used up and the minimum curtailment amount was determined, which is 125MW for Trans3 in this example. However, the transactions not curtailed will have to cover the expensive service costs.

No matter how inexpensive or expensive the congestion cost is, the proposed cost minimization approach fully utilizes the transmission capacity so that the flow of line 21-22 are always kept at its specified limit.

7.4 Service Allocation

In previous section, the test results showed that there are costs involved to provide reactive support and real power loss services. These costs should be covered by the simultaneous transactions. In this section, the proposed average sensitivity method for service allocation was tested and is discussed. The results of the allocated cost are not shown in this section as they are purely the per unit cost multiplied by the allocated service amounts.

In order to test the three properties of the proposed method under both unstressed and stressed system conditions, the three transactions listed in Table 7.9 were selected. The total transaction amount was increased from 63MW to 1575MW. In this process, the loads at uninvolved buses, the proportion between the three transactions, and the power factors for loads were kept constant. The 1575MW value was the last feasible operating point before voltage collapse occured. The transition from an unstressed system to a stressed system is shown by the PV curve in Figure 7.15.

Table 7.9 List of the three transactions for service allocation

	Energy seller	Energy buyer	MW amount	MVar amount
Trans4	Bus 30	Bus 15	250	40
Trans5	Bus 2	Bus 22	240	0
Trans6	Bus 10	Bus 3	140	20

Tests results were compared using:

1. the average sensitivity method, with (a) one-function approximation, (b) two-function approximation, and (c) four-function approximation.

2. the traditional sensitivity method [55] using base case sensitivities.

3. the "major" and "interaction" component method [70], and

4. the "aggregated" component method [58].

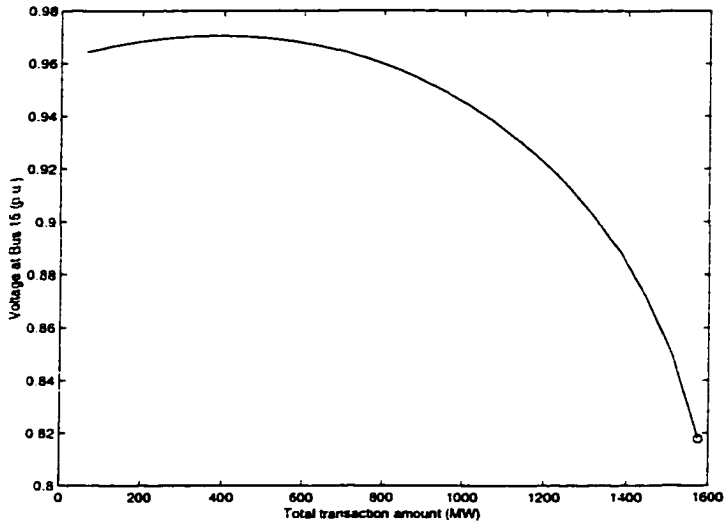


Figure 7.15 PV curve: from unstressed to stressed system

7.4.1 Loss Allocation Quantity and Ratio

It is known that transmission losses are approximately a second-order function of transactions under unstressed system conditions [82]. For a stressed system, this characteristic no longer holds. Figure 7.16 illustrates this characteristic through the loss sensitivities.

The loss allocation quantity mismatches are shown in Figure 7.17 with total transaction amount ranging from 63MW to 1512MW. Compared with traditional sensitivity approach, the average sensitivity method has far better behavior in the sense of allocation quantity no matter whether the system is stressed or unstressed. Compared with the two power flow based approaches, the average sensitivity method has a similar small mismatch except for the stressed cases.

When the system is unstressed, losses are approximately a second-order function of transactions. Loss allocation by the average sensitivity method has no mismatch as previously illustrated.

When the system becomes more stressed, loss sensitivity becomes increasingly non-linear. Allocation by running only one base case and one final case (one second-order function approximation) produces a large mismatch. However, by performing additional one power flow (two-function approximation) or additional three power flows (four-function approximation),

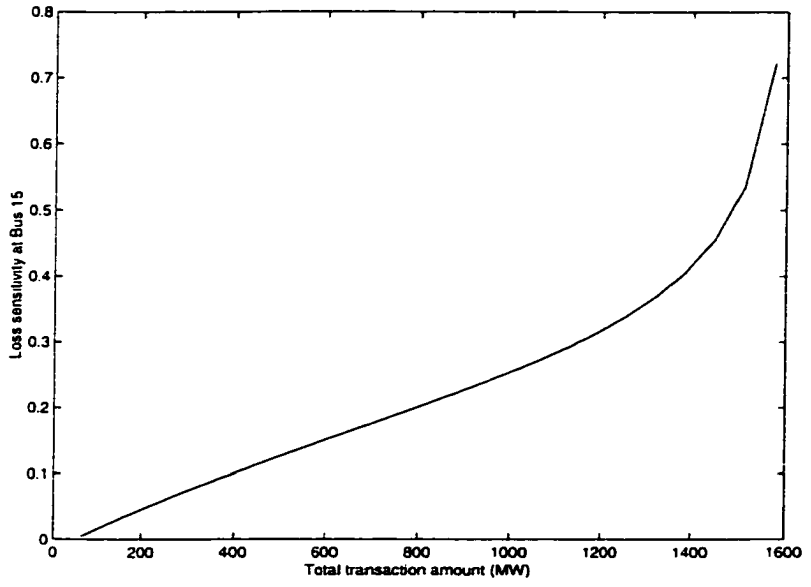


Figure 7.16 Loss sensitivity curve

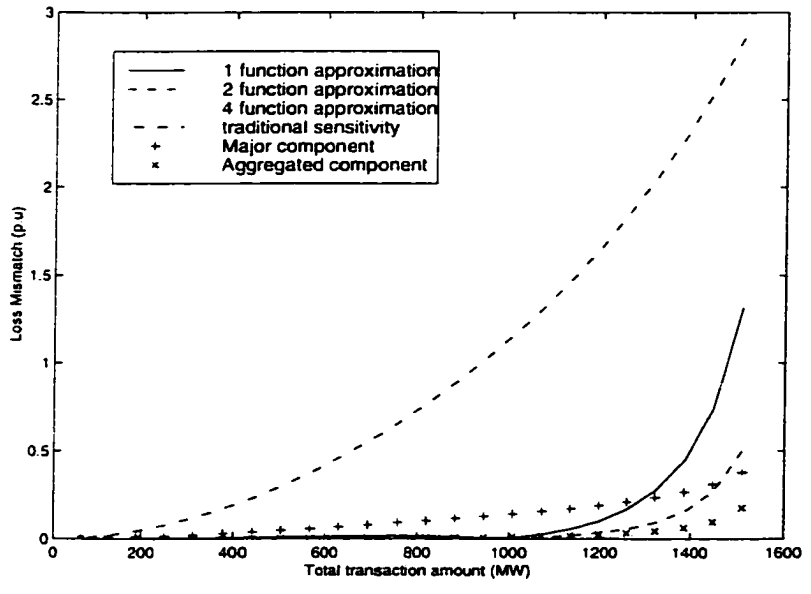


Figure 7.17 Loss allocation quantity mismatch curves

the mismatch is reduced quickly and reaches the same mismatch range as the power flow based approaches.

The comparison of the loss allocation ratio for Trans4 is shown in Figure 7.18. It is observed that average sensitivity method provides the same allocation ratio when compared to power flow based approaches. Therefore, by using these ratios, the true loss allocation quantity for Trans4, obtained according to Equation 6.20, is shown in Figure 7.19. A tendency has been observed that when the number of approximation functions increases from one to two, to four, the allocation quantity approaches a fixed value. This fixed value, although it could never be achieved, is the basis for comparison.

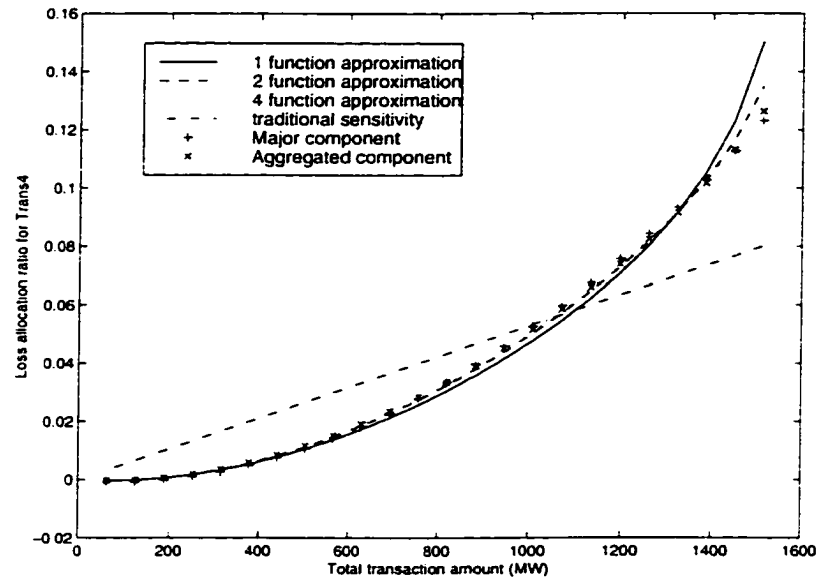


Figure 7.18 Loss allocation ratio

7.4.2 Reactive Support Allocation Quantity and Ratio

The characteristic of reactive power sensitivity for the generator at Bus 10 in this system is shown in Figure 7.20. The sensitivitity is quite linear when the system is unstressed. When the system becomes increasingly stressed, the sensitivitity becomes non-linear.

For the previous three transactions, the mismatch of reactive allocation quantity, allocation ratio, and the true allocation quantities are shown in Figures 7.21, 7.22 and 7.23, respectively.

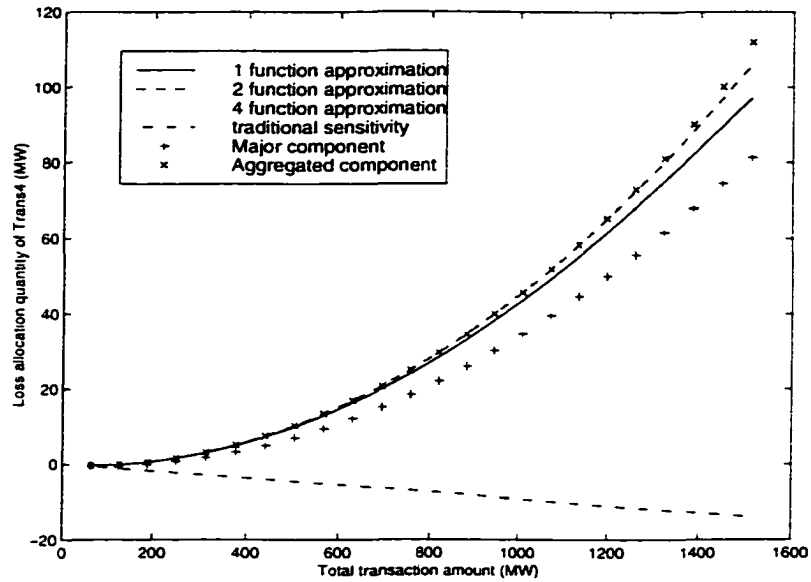


Figure 7.19 Loss allocation quantity

Since the characteristic of reactive power sensitivity looks similar to the loss sensitivity, the behavior of proposed method for reactive suppport service allocation are similar to that of loss allocation. It provides as good results as power flow based approaches.

7.4.3 Application Feasibility

It is noted that the allocation results at the last feasible operating point (total transaction amount 1575MW) was not included in the previous comparison. Although we can still obtain the results of average sensitivity method, the power flow based approaches fail to reach an answer because of the diverge power flow around that point.

Compared to power flow based methods, the average sensitivity method is advantageous in term of computation time. Figure 7.24 shows the number of power flows for each method.

For the power flow based approach, the number of power flows required is proportional to the number of transactions. When a large number of transactions is involved, the allocation takes a long time. For the average sensitivity method, the number of power flows is proportional to the number of approximation functions. Under most operating conditions, a four-approximation function provides good results.

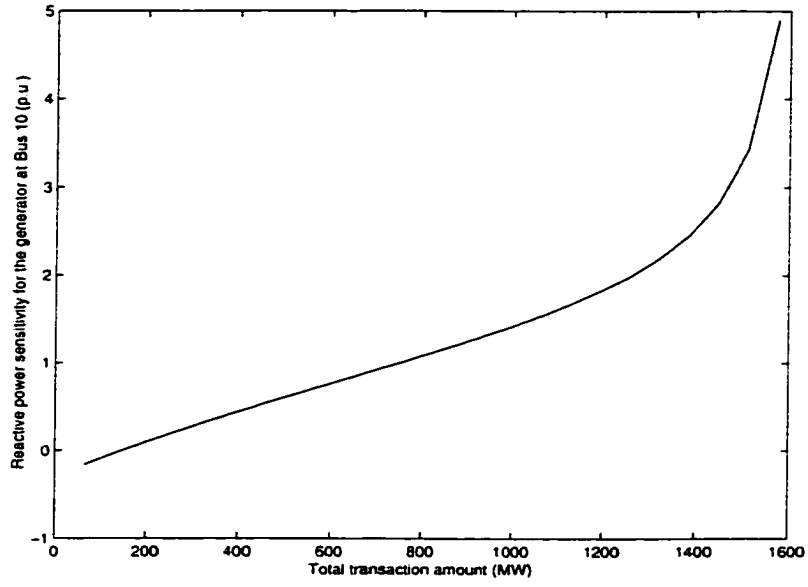


Figure 7.20 Reactive power sensitivity curve for the generator at Bus 10

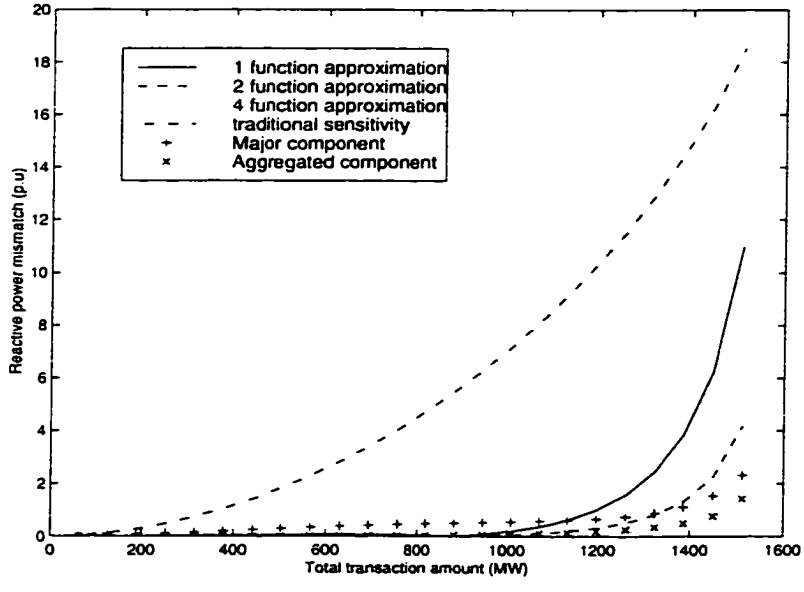


Figure 7.21 Mismatch of reactive support allocation quantity

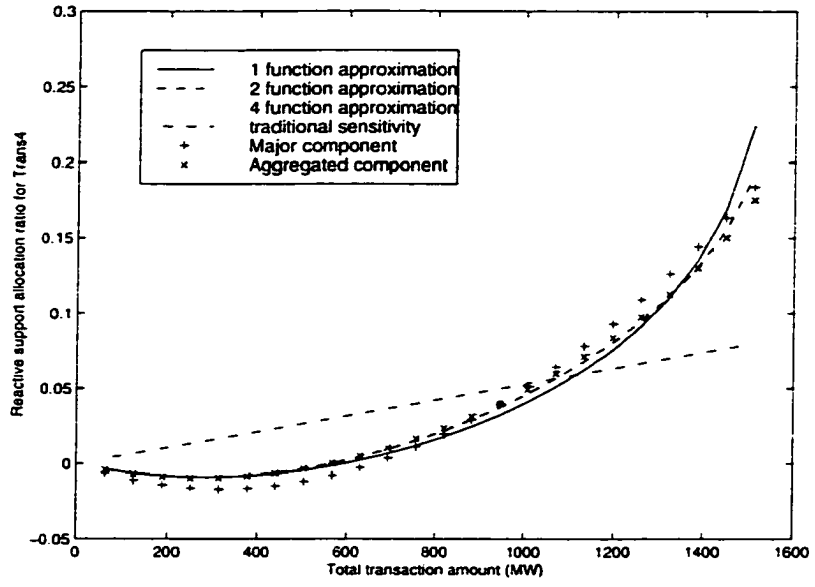


Figure 7.22 Reactive support allocation ratio

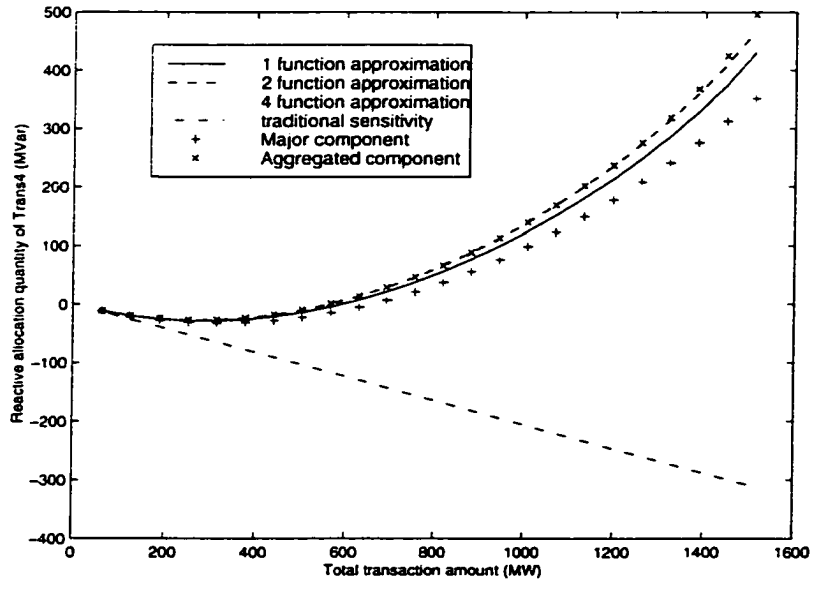


Figure 7.23 Reactive support allocation quantity

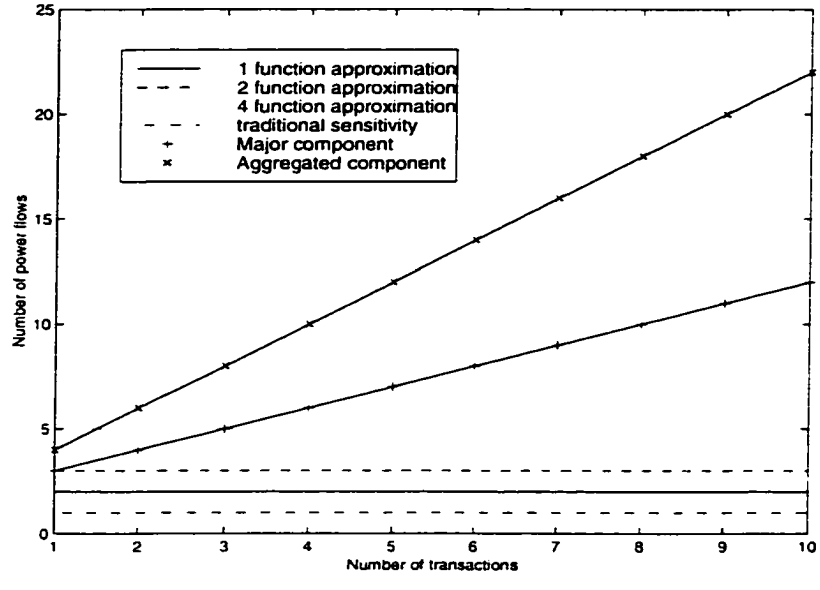


Figure 7.24 Number of power flows required

8 SUGGESTIONS FOR FUTURE WORKS AND CONCLUSIONS

8.1 Suggestions for Future Work

The research presented in this dissertation was an attempt at developing a framework for the independent system operator to identify and allocate reactive support and real power loss services. Related work also includes the cost evaluation and bid preparation for the two services. While progress was made in this research, it is recognized that many issues remain unsolved, and many problems unsolved in this area. The following areas are suggested for further research.

8.1.1 Economic Cost Analysis and Bid Preparation

- In this research, the economic cost is analyzed for the reactive support and real power loss services. However, there are several other services involved in the market-based power system operation. They are spinning reserve service, non-spinning reserve service, regulatory and frequency response service, energy imbalance service and several interconnected services. Most of these services are products of generation sources. It would be of value to extend the opportunity cost concept for their economic cost evaluation.

- The market participants in this research are assumed to be the owner of only one generator. Their opportunity costs are therefore evaluated based on the capacity of a single generator. This is a very simple assumption, in order not to distract from the basic concept of opportunity cost. For a power company who has the control over more than one generator, its the opportunity cost evaluation should take more factors into consideration, such as the factor of unit commitment schedules.

- The evaluation of the expected profit affects the opportunity cost. Because of various uncertainties, the bidding strategy should be used by individual participant to maximize the profit. The strategy adopted in this research comes from the work of [9]. Although developing bidding strategy is not major part of this research, it might worth to include other strategies into the opportunity cost evaluation. Meanwhile, the inclusion of other uncertainties and variants in cost evaluation can also be part of the future work.

- Since a generator is designed to produce both real and reactive power, the capital cost investment of generators should be split into real and reactive power-related terms. In this work, the power triangle provides a practical method for the splitting. Further investigation can be done to see whether other approaches such as valuation proxy of synchronous condensers could be applied.

- Rational behavior of market participants were assumed throughout the research. The rational behavior of utility maximization may take other forms than profit maximization. In addition, irrational behaviors are also observed occasionally. How to incorporate different utility functions and consider irrational behaviors might be good candidates for further research.

8.1.2 Service Identification and Congestion Management

- In this research, the analysis of service identification is based on the market model assumptions, i.e. energy markets are double-auction models and bilateral contracts, and the service markets are single-auction models. Under some deregulation rules, different models may be allowed for the energy and service markets. This analysis can be extended to incorporate other models. Some research could be done to investigate the pros and cons for different market models in congestion management and service identification.

- A total profit maximization procedure is proposed in this research for congestion management and service identification. It is equivalent to the cost minimization where the total cost of congestion and services are minimized. This approach treats the security

(congestion) and economy (cost of services) equally in terms of value. It would be of interest to apply weighting factors to the congestion and service costs to evaluate the comparative importance of security and economy.

- In Table 1.4, several factors were listed, that could affect the congestion management and the service identification. Of these, only a limited number have been discussed within this research. Inclusion of some others of these factors would be a natural extension of this work. Examples include the inclusion of voltage stability conditions.

- Because linear programming is a mature technique and because of its easy implementation in the MATLAB, it was selected in this research to solve the optimization procedure. As seen in Section 7.3.1, the overall convergence speed of LP is not ideal as the coefficient of objective function could be quite non-linear. Other non-linear optimization techniques could be tried. A possible candidate could be the interior point method solve by Newton's approach.

8.1.3 Service Allocation

- The illustrative examples described in Section 7.4.2 are somewhat limited by the nature of the test system. The reactive power sensitivity is quite linear when system is unstressed. This characteristic may not hold if the system includes any non-linear devices, such as static voltage systems. It would be of value to test the properties of average sensitivity method in these cases.

- The existence of the base case is an assumption made in service allocation. A possible, although unlikely, case is that all the flows in the system are the result of transactions that are using the system simultaneously. Extending average sensitivity method for service allocation in this case is a possible future work topic.

- In this research, the allocation of services are limited to the reactive support and real power loss services. For other ancillary services and interconnected service, this method can only be used if proper sensitivities can be obtained. How to apply the average

sensitivity method for those services would be an interesting and challenging area for future research.

8.2 Conclusions

In this research, a framework has been presented for the ISO to management congestion and identify reactive support and real power loss services. The framework includes the market-based power system operation analysis, individual behavior analysis in costing and bid price determination, the ISO's behavior analysis in congestion management and service identification, and the analysis of service allocation by the ISO. The following sections present the conclusions reached from this research.

8.2.1 Congestion Management and Service Identification

The ISO's decision in congestion management and service identification is dependent on the model of the market-based power system operation. A possible representation of the structure for the combined energy markets, service markets, databases, and the ISO was defined in this research. It can be used to analyze the behavior of market participants and the ISO.

The ISO's decisions affect the profit of individual market participants. A rational behavior of a producer is to maximize the profit. However, in the process of service identification, it is impossible to guarantee that every participants' profit is maximized. By analyzing the cash flow among the participants, a total profit maximization was proposed as an objective function for service identification and congestion management.

Given the limited information that is available to the ISO, a lower bound profit maximization is a substitute for the ISO to make the decisions. These decisions are based on the energy market bids and service market bids that are submitted to the ISO for evaluation. It is equivalent to minimizing the upper bound cost of congestion (losses if energy is curtailed) in addition to the upper bound cost of services (the money that the ISO pays to the services providers).

Because of the technical interdependence among the real and reactive powers, an opti-

mization procedure was set up to identify the two services simultaneously while managing congestion. It was concluded that the overall cost minimization results in a smaller transaction curtailment, as compared with the results if the decisions are made separately.

Service identification and congestion management are two important activities in the ISO's day-ahead scheduling function. In general, more transactions require more services. The proposed optimization procedure helps in the optimal allocation of scare resources. For energy market participants, those who value it most and are willing to pay for the service costs will get the least adjustment.

8.2.2 Economic Cost Analysis and Bid Preparation

The ISO's decisions, in the short run, only depend on the bids submitted by market participants. This research provides a possible method for the service providers to evaluate the cost of service and prepare the bids.

An analytic framework for analyzing the economic cost of the reactive support and real power loss services is provided in this research. The concept of economic cost has been widely used in economic analysis. It represents the true cost so that the economic profit can be evaluated, the results of which will affect the behavior of producers.

In this research, the economic cost was introduced to evaluate the reactive support and real power loss services from generation sources and transmission sources. It is composed of the explicit and opportunity costs. Because of the various markets in which a producer can be involved, the opportunity cost reflects the intermarket correlations. The opportunity cost for each generation-related service was identified to be the maximum profit of the used capacity. This could be significant in some situations.

The concept of economic and opportunity costs was applied in this research to evaluate the cost of reactive support and real power loss services. Because of the uncertainty involved in the market conditions, strategic bidding was used to estimate the profit in each market.

The bid preparation is an individual activity. Market participants have the right to bid any price that they think is proper. However, the concept of economic cost helps them to prepare

the bids for the separate markets, which could otherwise be very complicated. The profit maximization of each individual market leads to the total profit maximization considering all markets.

8.2.3 Service Allocation

Since there are service costs involved to support transactions, these costs should be allocated by the ISO to all transmission users. The cost allocation was based on the service allocation and, in this research, an average sensitivity method was proposed to solve this problem.

Three properties must be satisfied for an allocation algorithm to be considered successful. It must guarantee the allocation quantities, allocation ratios and application feasibility. Full cost recovery must be realized. The allocation ratios should reflect fairness, i.e. allocations should be based on the actual usage of the services by the individual transactions. The allocation method should be feasible in practical application, i.e. there should be no convergence problems and the method should require only limited computational time and storage.

The average sensitivity is a significant improvement from the previously used power flow-based and sensitivity-based approaches. Theoretical evidence indicates that for a second-order service function, this method guarantees full cost recovery. For higher-order service functions, the allocation quantity mismatch can be reduced and eliminated by piecewise approximations. These transaction sensitivities correctly reflect the usage of the services.

The average sensitivity method was applied to the reactive support and loss allocations. Practical implementation does not require complicated mathematical calculations. Under most operating conditions, the average reactive support sensitivity and average loss sensitivity require only a limited number of power flows. Since the allocation is performed after the optimal service is identified, the allocation amount will not affect the ISO's decisions.

8.3 Final Summary

In conclusion, this research has provided a framework for the ISO to identify and allocate ancillary services and other interconnected services. A clear definition of the problems and

their background has been presented. Attempts were made to maximize the total profit of all market participants. As a preparation for service identification, an analytic framework was also developed in this research, which analyzes the cost of services and prepares the related bids. An average sensitivity method was proposed to allocate the cost of services to transmission users. Although attempts were only made to identify, evaluate and allocate the services of reactive support and real power losses, the research could be extended to other services, which are or will be involved in the market-based power system operation.

From the good results obtained in this work, it is expected that the practical application of this research will bring significant benefits to the energy and service market participants in the deregulated environment. Since the total profit maximization is designed to be the additional objective for the ISO's decision making, it will finally increase the welfare of the end customers. This work will also be applicable to future researchers in this area.

APPENDIX A LINEAR SENSITIVITY ANALYSIS

Linear sensitivity coefficients provide an indication of the change in one system quantity as another quantity is varied. These linear relationships are essential for the application of linear programming.

For the proposed optimization procedure, the sensitivities that are of interest are the sensitivities of state variables with respect to control variables, and other variables with respect to the control variables. The state variables are voltage magnitude V_i and angle δ_i. The control variables include transaction curtailment ΔP_t, generator voltages V_g, swing bus distribution factors K_i, tap ratios of transformers ΔTap_x, and the reactive outputs of the capacitors Q_c. Other variables are line flow S_{ij}, transmission losses P_l, and reactive power output of generators Q_g. The change of ΔP_t and Q_c can be transformed into the change in real and reactive power injections, P_i and Q_i, at the involved buses.

The inverse of the augmented Jacobian matrix contains almost all information of the sensitivities. The elements are derived as follows:

$$f_{i,p} = \sum_j (V_i^2 G_{ij} - V_i V_j G_{ij} cos(\delta_{ij}) - V_i V_j B_{ij} sin(\delta_{ij})) - (P_i^{(s)} + K_i P_l) \tag{A.1}$$

$$f_{i,q} = \sum_j (-V_i^2 B_{ij} - V_i V_j G_{ij} sin(\delta_{ij}) + V_i V_j B_{ij} cos(\delta_{ij})) - (Q_i^{(s)}) \tag{A.2}$$

There are two equations (Equations A.1 and A.2) for each bus, which represent the balance of real and reactive powers. The known and unknown variables for all equations associated with a distributed swing-bus power-flow calculation are listed in Table A.1.

Note, the $V\delta$ bus is not the swing bus in the traditional sense. It only represents a bus, whose angle is selected as the reference and it is not required to be a generator bus.

Table A.1 List of known and unknown variables

	unknown	known
PQ Bus	V_d, δ_i	$P^{(s)}$,$Q^{(s)}$
PV Bus	Q_g,δ_i	$P^{(s)}$,V_g
Vδ Bus	Q_g	$P^{(s)}$,V_g,δ_i
Loss	P_l	

Among those variables, there are a total of $2n$ unknowns. They can be solved simultaneously by the $2n$ equations in Equations A.1 and Equations A.2. Although the generator voltages, swing bus distribution factors, and the tap ratio of transformers are constant within a power flow iteration, they can be augmented in the Jacobian matrix so that the sensitivities related to them can be obtained. The Jacobian matrix thus is formed as follows:

$$J = \begin{bmatrix} \frac{\partial f_{i,p}}{\partial V_{d,i}} & \frac{\partial f_{i,p}}{\partial Q_{g,i}} & \frac{\partial f_{i,p}}{\partial \delta_i} & \frac{\partial f_{i,p}}{\partial P_l} & \frac{\partial f_{i,p}}{\partial V_g} & \frac{\partial f_{i,p}}{\partial tap} & \frac{\partial f_{i,p}}{\partial K_i} \\ \frac{\partial f_{i,q}}{\partial V_{d,i}} & \frac{\partial f_{i,q}}{\partial Q_{g,i}} & \frac{\partial f_{i,q}}{\partial \delta_i} & \frac{\partial f_{i,q}}{\partial P_l} & \frac{\partial f_{i,p}}{\partial V_g} & \frac{\partial f_{i,p}}{\partial tap} & \frac{\partial f_{i,p}}{\partial K_i} \\ 0 & 0 & 0 & 0 & I & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & I & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & I \end{bmatrix} \tag{A.3}$$

Each individual term in the above matrix can be derived from Equations A.1 and A.2. It is nonsingular except for the case of voltage instability. The inverse matrix has almost all the sensitivities that is required in this research, as shown in the following expression:

$$J^{-1} = \begin{bmatrix} \frac{\partial V_{d,i}}{\partial f_{i,p}} & \frac{\partial V_{d,i}}{\partial f_{i,q}} & \frac{\partial V_{d,i}}{\partial V_g} & \frac{\partial V_{d,i}}{\partial tap} & \frac{\partial V_{d,i}}{\partial K_i} \\ \frac{\partial Q_{g,i}}{\partial f_{i,p}} & \frac{\partial Q_{g,i}}{\partial f_{i,q}} & \frac{\partial Q_{g,i}}{\partial V_g} & \frac{\partial Q_{g,i}}{\partial tap} & \frac{\partial Q_{g,i}}{\partial K_i} \\ \frac{\partial \delta_i}{\partial f_{i,p}} & \frac{\partial \delta_i}{\partial f_{i,q}} & \frac{\partial \delta_i}{\partial V_g} & \frac{\partial \delta_i}{\partial tap} & \frac{\partial \delta_i}{\partial K_i} \\ \frac{\partial P_l}{\partial f_{i,p}} & \frac{\partial P_l}{\partial f_{i,q}} & \frac{\partial P_l}{\partial V_g} & \frac{\partial P_l}{\partial tap} & \frac{\partial P_l}{\partial K_i} \\ 0 & 0 & I & 0 & 0 \\ 0 & 0 & 0 & I & 0 \\ 0 & 0 & 0 & 0 & I \end{bmatrix} \tag{A.4}$$

The only sensitivity that is not directly contained in the above matrix is the sensitivity of line flow with respect to the control variables. Since the sensitivity of line flow with respect to the state variables V_i and δ_i can be derived through the expression of line flow, the sensitivity with respect to each control variable can thus be obtained according to the chain rule.

APPENDIX B LIST OF RELATED DATA

The data that was used in Section 7.3 is presented in this section. The data for the transformers and capacitor banks are listed in Tables B.1 and B.2 respectively. The data of generators in this system are listed in Table B.3 and B.4.

Table B.1 Data for transformers

	Branch 11-12	Branch 12-13
installation cost	$\$1x10^6$	$\$1x10^6$
life time	40 year	40 year
average step change per day	11	11
availability factor	98%	98%

Table B.2 Data of capacitors

	Bus 4	Bus 7	Bus 15	Bus 21	Bus 27
installation cost ($\$/MVar$)	11600	11600	11600	11600	11600
capacity ($MVar$)	50	50	$80r$	70	60
life time (year)	40	40	40	40	40
average switch per day	2	2	2	2	2
availability factor	98%	98%	98%	98%	98%

Table B.3 Data for Generator 1 to 5

	Gen 1	Gen 2	Gen 3	Gen 4	Gen 5
Bus	2	6	10	19	20
P_{max} (MW)	350	800	700	700	600
P_{min} (MW)	100	150	200	200	150
Q_{max} (MVar)	350	400	300	300	250
Q_{min} (MVar)	-100	-300	-300	-300	-250
I (\$/MW)	800K	769K	797K	797K	769K
yr	30	30	30	30	30
af	85%	85%	85%	85%	85%
lf	64%	64%	64%	64%	64%
pf	0.9	0.9	0.9	0.9	0.9
MC_{min} (\$/MW)	7.92	7.62	6.90	6.90	7.85
MC_{max} (\$/MW)	9.68	10.04	11.23	11.23	10.65

Table B.4 Data for Generator 6 to 10

	Gen 6	Gen 7	Gen 8	Gen 9	Gen 10
Bus	22	23	25	29	30
P_{max} (MW)	700	800	700	900	1300
P_{min} (MW)	200	150	150	300	400
Q_{max} (MVar)	400	350	300	250	900
Q_{min} (MVar)	-250	-250	-220	-250	-800
I (\$/MW)	797K	769K	769K	686K	591K
yr	30	30	30	30	30
af	85%	85%	85%	85%	85%
lf	64%	64%	64%	64%	64%
pf	0.9	0.9	0.9	0.9	0.9
MC_{min} (\$/MW)	6.46	7.90	7.50	7.90	8.10
MC_{max} (\$/MW)	11.45	12.09	9.64	11.78	12.92

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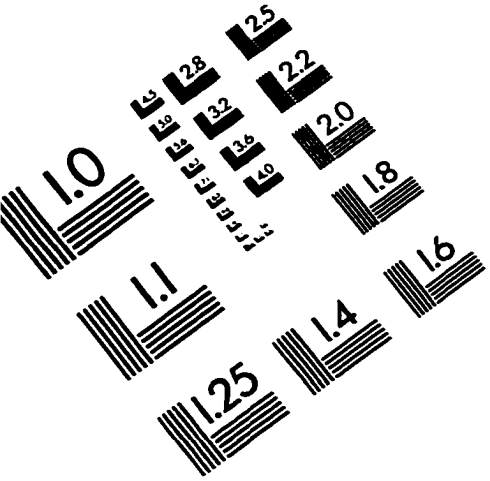
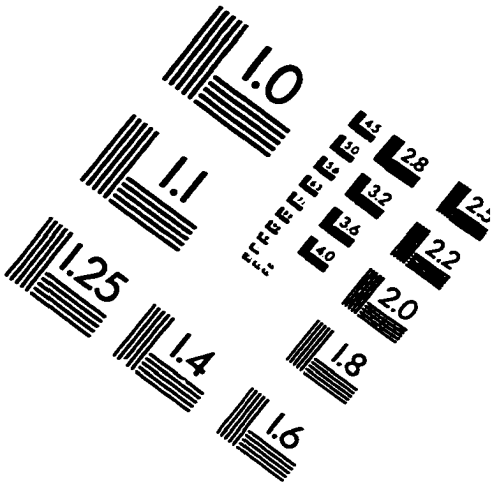
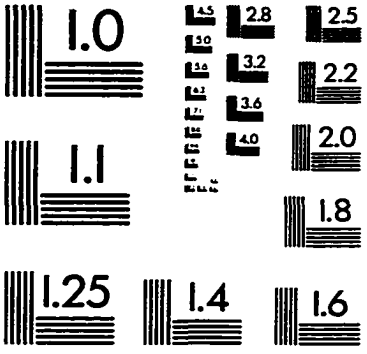
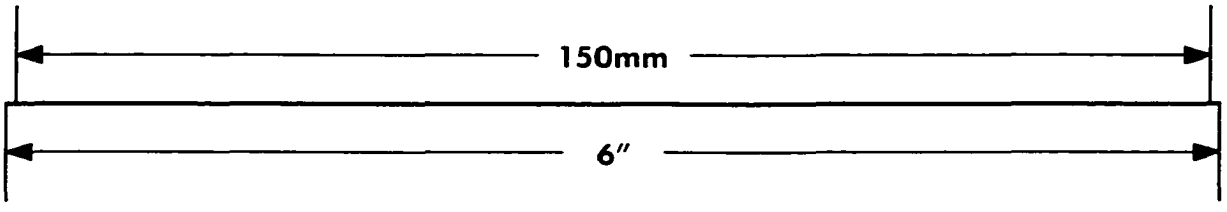
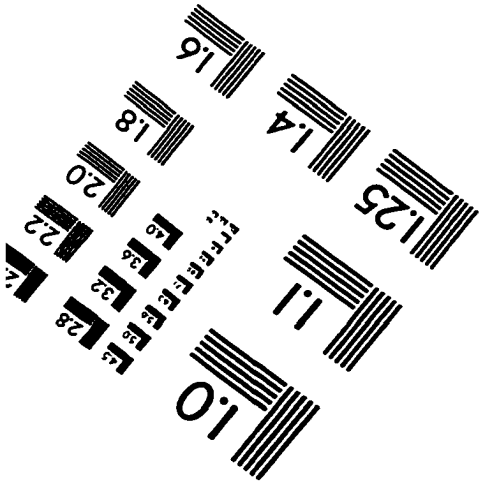
IMAGE EVALUATION TEST TARGET (QA-3)

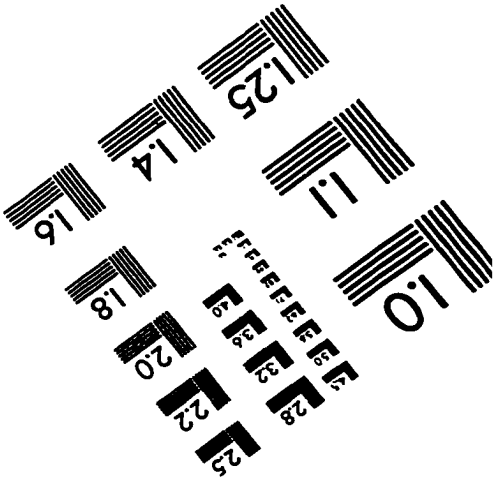












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