THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

INTERRUPTIBLE LOAD SERVICES IN DEREGULATED POWER MARKETS

by

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ABSTRACT

Since the nineties decade, many electric utilities world-wide have been restructuring their systems from vertically integrated functioning to deregulated open-market ones. In the erstwhile vertically integrated utilities, the system operator sought to maximize the social welfare with distributional equity (meeting the load at all time) as the main criteria, for the system as a whole. The operating paradigm was based on achieving the system solution while meeting reliability and security margins. This often led to investment in such generating capacity that operated at very low load factors. Decommissioning of generating capacity, particularly those operating at low load factors, was thus an expected outcome when such vertically integrated utilities moved over to deregulated market operations. The erstwhile objective of maximizing social welfare with distributional equity was then replaced by a profit-maximizing objective, which was nothing but maximizing social welfare with *efficiency* as the main criteria for the generating companies. As a consequence, power producers are no longer obliged to provide for the system reliability margin in deregulated markets. Additionally, new investments in generating capacity are not easily forthcoming since these are prerogative of private investors who look for a high internal rate of return on a project, and that becomes increasingly difficult to ensure in the competitive markets.

The above mentioned problems associated with deregulation has triggered a need for the research and implementation of interruptible load management - ILM (which basically offers the much needed demand reduction during the system critical conditions within a short notice to avoid system security problem) in deregulated system operations. Though this concept is not new, but it has been proved justifiable to use it now. Hence, this thesis. This thesis proposed a market structure for interruptible load customers where they can offer to sell part of their demand as part of the ancillary service market procured by the independent system operator. The operational objective of the market is minimizing the total ILM procurement costs while satisfying all the system constraints. The thesis also examines the operational roles of interruptible load in cases of contingencies and in cases of high demand in the power systems, especially the ability of the interruptible load market in providing transmission congestion relief. In order to provide a comparison of the economic viability of ILM over the generating option, a cost-benefit analysis of the long-term investment on a fast start-up generator as part of the system operating reserve has been studied.

Keywords: deregulated electricity market, interruptible load management, ancillary services, congestion management, reserve generation, optimal power flow.

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LIST OF PUBLICATIONS

[1] L.A. Tuan, K. Bhattacharya, "Interruptible Load Management Within Secondary Reserve Ancillary Service Market", in Proc. of IEEE Porto PowerTech'2001 Conference, Vol. 1, Porto, Portugal, September 10-13, 2001.

[2] L.A. Tuan, K. Bhattacharya, "A Review on Interruptible Load Management: Literature and Practice", in Proc. of 33rd North American Power Symposium, Texas, USA, October 15-16, 2001, pp. 406-413.

[3] L.A. Tuan and K. Bhattacharya, "Interruptible Load Services for Transmission Congestion Relief", Accepted for presentation at 14th Power Systems Computation Conference (PSCC '02), Sevilla, Spain, June 24-28, 2002.

[4] L.A. Tuan and K. Bhattacharya, "Long-Term Congestion Management Using Gas Turbine Generators: Cost-Benefit Analysis", Submitted to IEE Proceedings.

LIST OF SYMBOLS AND ACRONYMS

i,j,k	Bus index
h	Hour index
Type	Customer type index
CI	Congestion index
CL	Compensation for loss, $/p.u. MW
GT	Gas turbine capacity, p.u. MW
L	Total system loss, p.u. MW
LS	Load share of a customer Type at a bus, %
LSF	Hourly load scaling factor
N	Total number of buses
NG	Total number of generating buses
NGT	Total number of gas-turbine generators
NL	Total number of load buses
NILM	Total number of ILM buses
PD	Real power demand, p.u. MW
PD_m	Real power demand on spot market, p.u. MW
PD_b	Real power demand on bilateral contract, p.u. MW
PDem	Real power demand by customer type, p.u. MW
PF	Power factor of load
PG	Real power generation, p.u. MW
PG_m	Real power generation for sale on spot market, p.u. MW
PG_b	Real power generation for bilateral contract, p.u. MW
PG^{max}, PG^{min}	Real power generation limits, p.u. MW
PGcon	Contracted generation, p.u. MW
PVIOL	Violated transmission capacity, p.u. MW
ΔPD	Real power interruption, p.u. MW
ΔQD	Reactive power relieve, p.u. MW
QC	Reactive power compensation, p.u. MVAr
QC^{max}, QC^{min}	Reactive power compensation limits, p.u. MVAr
QD	Reactive power demand, p.u. MVAr
R	Operating reserve margin requirement, p.u. MW
RLIM	Reserve limit above which interruptible load market is not required to operate, p.u. MW
U	Binary variable denoting the selection of an interruptible load contract
UC	Unit commitment decision, 0/1
V	Bus voltage, p.u.
V^{max}, V^{min}	Upper and lower limits on bus voltage, p.u.

VC	Transmission violation cost, \$/p.u. MW
Y	Element of network admittance matrix, p.u.
Y_{ch}	Charging admittance matrix, p.u.
B	Element of susceptance matrix, p.u.
θ	Angle associated with Y, radianVoltage angle, radian
λ	Marginal loss coefficient at a bus, p.u. MW/p.u. MW
β	interruptible load offer price, \$/p.u. MW
μ	Interruptible load offer quantity, p.u. MW
ρ	ISO pay price to selected interruptible load offers, \$/p.u. MW
a_0	Scalar multiplier denoting the fraction of total demand of a particular load type at a bus, at its disposal
a_1, a_2	Scalar multipliers

BCR	Benefit-to-Cost Ratio
CRM	Congestion Relief Model
CRI	Congestion Relief Index
DSM	Demand-side Management
ISO	Independent System Operator
ILM	Interruptible Load Management
OPF	Optimal Power Flow

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CHAPTER 1

INTRODUCTION

This chapter presents a brief overview of power industry deregulation and the situation in Sweden in this regard. Various implications of deregulation, such as decreasing reserve margins, price volatility, and lack of incentive for investment in generation capacity, are discussed. In this context, interruptible load management is gaining increasing importance as a means for additional operating reserve in the system. The objectives of this study, aimed at addressing various issues related to operating of the interruptible load management programs in deregulated electricity markets are laid out. A brief outline of various chapters of this thesis is also provided.

1.1 Deregulation of the Electricity Supply Industry

Since the last two decades, many electric utilities world-wide have been forced to change their ways of doing business, from vertically integrated functioning to open-market systems. The reasons have been many and differed across regions and countries.

In developing countries, the main issues have been high demand growth associated with inefficient system management and irrational tariff policies, among others. This has affected the availability of capital investment in generation and transmission systems. In such a situation, many countries were forced to restructure their power sectors under pressure from international funding agencies. On the other hand, in developed countries, the driving force has been to provide the customers with electricity at lower prices and to offer them greater choice in purchasing electricity.

Deregulation was undertaken by introducing commercial incentives in generation, transmission and distribution of electricity. The main objective of deregulation is to achieve a clear separation between production and sale of electricity, and network operations. The erstwhile vertically integrated system operation has been separated into independent activities. The generation companies sell energy through competitive long-term contracts with customers or by bidding for short-term energy supply at the spot market.

On the other hand, with significant levels of "economy of scale", it was natural for the transmission sector to become a monopoly. It was therefore necessary to introduce regulation in transmission so as to prevent it from overcharging for its services.

Consequently, the transmission grid has to be a neutral monopoly subject to regulation by public authorities. New regulatory framework has been established to offer third parties "open access" to the transmission network so as to overcome the monopolistic characteristics of transmission.

In this deregulated environment, a system operator is assigned the central coordination role with the responsibility of keeping the system in balance, *i.e.,* to ensure that the production and imports continuously match the consumption and export. It is required to be an "independent" authority without any involvement in the market competition nor owning any generation facility for business (except some for emergency use). Hence its name Independent System Operator, largely known as ISO.

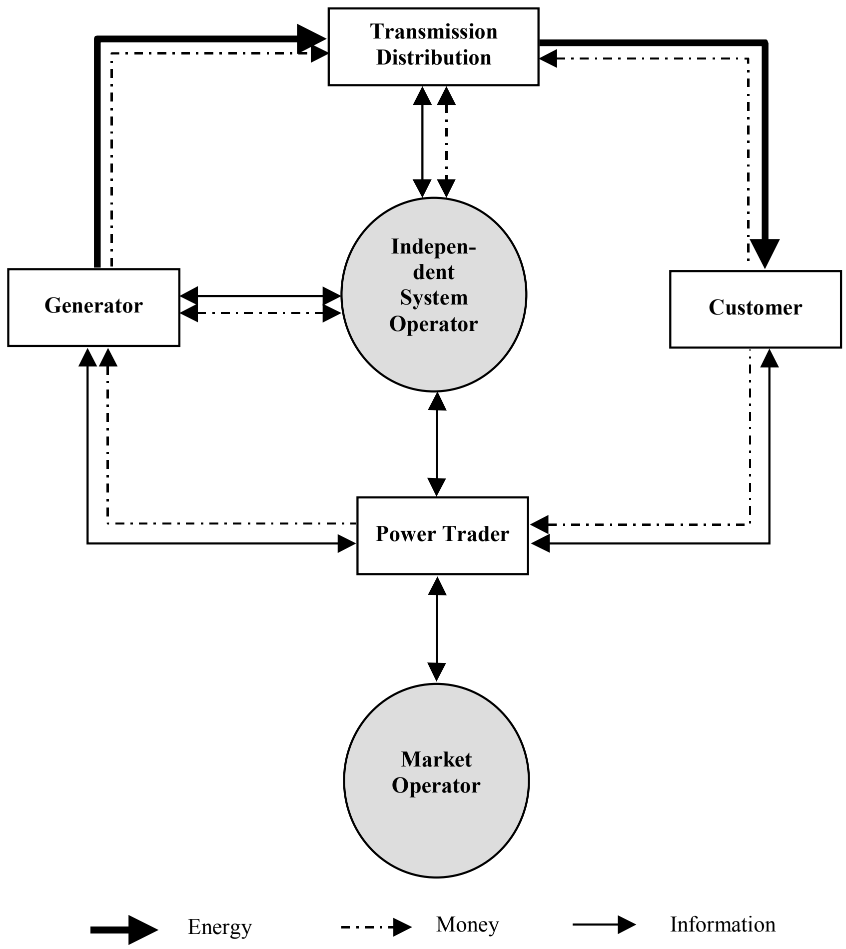

Figure 1-1: Typical structure of a deregulated power system

Figure 1-1 shows a typical structure of a deregulated power system with the complex interactions amongst different actors in the system.

Among the countries whose electricity supply industry has been deregulated, the South American countries, including Chile, Argentina, Bolivia, Colombia, Peru, and Brazil were the initiators of deregulation in, as early as, 1982. The United Kingdom, Norway, Australia, New Zealand, United States, Sweden and other European countries have subsequently opened up their power sectors to competition in the nineties. It should, however, be noted that the form of deregulation differs in each country and even among various systems in the United States.

1.2 The Swedish Electricity Market

The Swedish electricity market was reformed on January 1, 1996 when competition was introduced regarding production and sales of electricity. The Swedish market now consists of electricity producers, final customers, network owners, power trading companies, and an ISO, Svenska Kraftnät, which also manages the national high voltage transmission network. Some of the characteristic features of the Swedish market are as follows [1]:

- *Final electricity customers*, everything from industries to households, must have an agreement with an electricity supplier in order to be able to buy electricity.
- The production plants are owned by the *electricity producers*. In Sweden, about half the power produced is hydropower and the other half nuclear power.
- *A power trading company* can have several roles: that of an electricity supplier as well as a balance provider. Further, the power trading company can either have the balance responsibility itself or purchase this service from another company. The power trading company can purchase power on Nord Pool or directly from an electricity producer or another trading company.
- *The network owners* are responsible for transmitting the electrical energy from the production plants to the consumers. This is achieved though the national grid, the regional networks and the local networks, which are all owned by different network companies. The regional networks transmit power from the grid to the local networks and sometimes to major consumers, for instance industries. The local networks distribute power to the final customers within a certain area. All network owners report their consumption and production measurements to Svenska Kraftnät's settlement system.

- Svenska Kraftnät owns the national grid and has the role of *independent system operator*. This means that it ensures that production/imports correspond to consumption/exports and that the Swedish electricity plants work together in an operationally reliable way.

1.2.1 Reduced Operating Margins

In the erstwhile vertically integrated utilities, the system operator sought to maximize the social welfare with distributional equity (meeting the load at all time) as the main criteria, for the system as a whole. The operating paradigm was based on achieving the system solution while meeting reliability and security margins. This often led to investments in such generating capacity that operated at very low load factors. As a result, the prices charged to customers would be high, since the utility required to recover its operational and investment costs.

Decommissioning of generating capacity, particularly those operating at low load factors, was thus an expected outcome when such vertically integrated utilities moved over to deregulated market operations. As can be seen from Figure 1-2, in Sweden, several generating units have closed down since 1996. About 2000 MW capacity was decommissioned in 1998 and about 1200 MW in 1999. Most of these units were gas based or condensing power units and were primarily being used for peak hour generation, and had high operating costs [2].

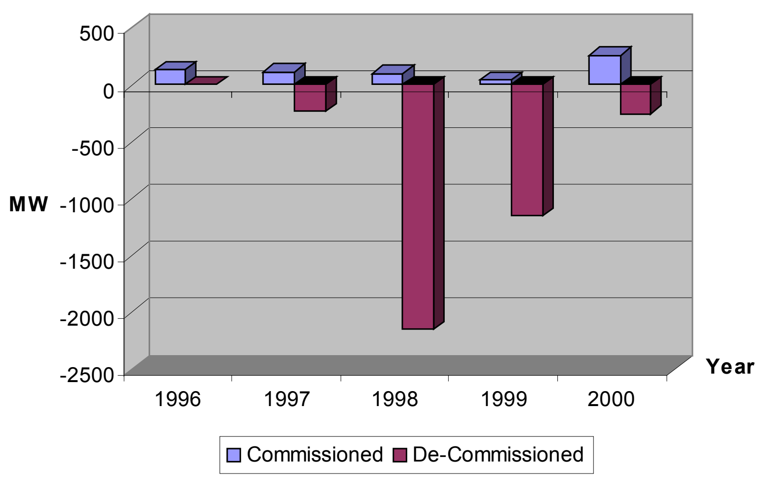

Figure 1-2: Capacity addition versus decommissioning in Sweden, after deregulation

(Source: Swedish National Energy Administration, http://www.stem.se)

Figure 1-3 shows the average monthly market prices in Nordpool for the Swedish market from 1996 (since its participation in Nordpool). It is clear that the market prices following a few years after deregulation had been decreasing with its lowest being in the summer of 1998. The low price trend continued until 2000. This could be attributed to a high level of competition among suppliers for attracting higher energy supply shares in the market and attracting customers, in the initial years. However, since the costly generation capacity could not sustain such low market prices, as shown in Figure 1-3, capacity decommissioning was the outcome. The subsequent increasing trend in average monthly market prices (Figure 1-3) since 2001 could be attributed to the resultant decrease in system operating margins which has acted as a signal to the major players.

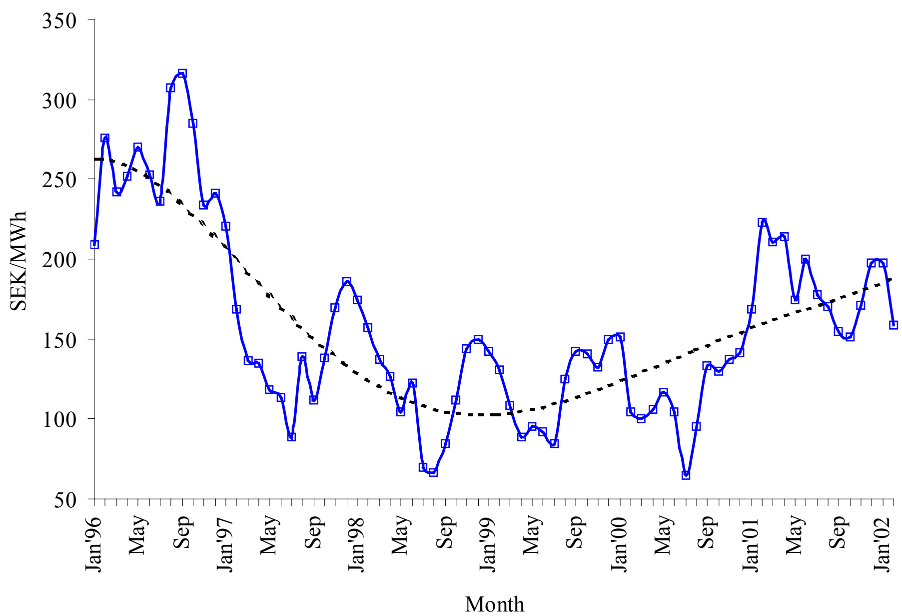

Figure 1-3: Spot market price in Nordpool for the Swedish electricity market

(Source: Nordpool ASA, http://www.nordpool.no)

Thus, it is apparent that competition in the electricity market has led to a decrease market price trends and hence in reserve margin in Sweden. Many factors account for this decrease, including insufficient construction of new generation and transmission facilities during the past several years. Figure 1-4 shows the total system capacity and total system load from 1996 to 2005 (2005 is forecast data). It is seen that there is very little new generating capacity planned for, during this period, while some more generating capacity is scheduled to be closed down. As a result, total system capacity has been decreasing, while the total system demand is increasing, thus making the system reserve margin lower.

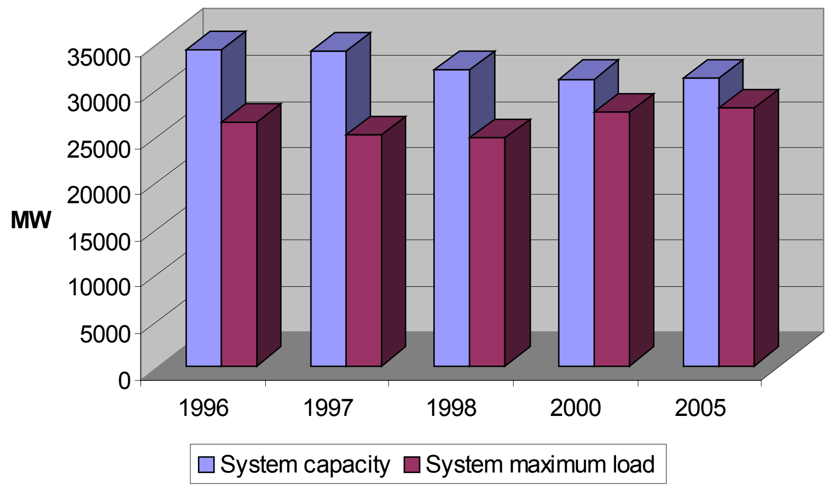

Figure 1-4: Sweden: The system margin is decreasing.

(Source: Swedish National Energy Administration, http://www.stem.se).

It should be noted that in deregulated electricity markets, new investments in generating capacity are not easily forthcoming since these are prerogatives of private investors who look for a high internal rate of return on a project, and that becomes increasingly difficult to ensure in competitive markets with uncertainties in market prices and other associated risks. This has an adverse impact on generation capacity addition in the system and leads to operating the system with very low security margin.

1.3 Interruptible Load Management (ILM)

In response to the reducing operating margins, particularly so in deregulated markets, interruptible loads could act as a useful tool for the ISO that can be invoked at times of critical system conditions, and provide the much needed system demand reduction and an operating reserve that can be activated within a short time.

In an interruptible load program, the customer signs a contract with the local utility or the ISO, as the case may be, to reduce its demand as and when requested (Figure 1-5). The utility benefits by way of reduction in its peak load and thereby saving costly generation reserves, restoring quality of service and ensuring reliability. The customer benefits from reduction in its energy costs and particularly from incentives provided by the local utility or the ISO. Provisions also exist in certain markets for the customers to offer their ability to modify their demand, which is referred to as *demand-side bidding*.

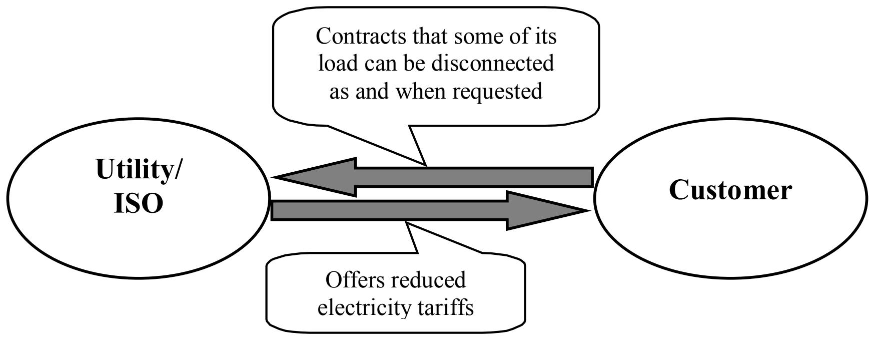

Figure 1-5: A typical interruptible load scheme

1.3.1 ILM as an Interest to Different Players in the Electricity Market

With power systems now operating under a capacity scarcity regime, in contrast to operating in classical vertically integrated and usually over-invested systems, energy efficiency and load management have assumed increasing importance. Even if prices are high during peak hours, uncertainty related to future profit has the consequence that the willingness to invest in peaking capacity, needed only occasionally, is very low. This has increased the interests among different market participants to offer load management and energy efficiency programs in a well functioning market. Incentives for interruptible load management can be derived by various players and actors in the market as described below:

- *Customers*: Customers are motivated by the potential of reducing energy costs, additional incentives from the utility, the possibility of freedom of choice and new customer services.
- *Electricity providers*: The electricity provider would be motivated by the possibility of diversification into new profitable business areas and customers services. Utilizing customer flexibility in order to reduce procurement costs in periods of high spot prices is another incentive.

- *Grid companies*: Grid companies are motivated by reduced marginal losses, improved utilization time, postponed investments and improved quality of services.
- *System operator*: The system operator is motivated by the possibility of improved operational reliability by including the demand interruption as a reserve for peak power reduction and for the provision of ancillary services.

1.3.2 Issues in Interruptible Load Management

i) Tariff Design

Most often, the problem lies in devising the rate structure, which should be incentive compatible to both utility and customer *i.e.,* minimize utility's costs and maximize the economic benefit of customer. Implementation of interruptible tariff involves unbundling electricity services and offers customers a range of rate reliability choices. Therefore, finding optimal utility-customer interactions and contracts is similar to finding the equilibrium point in an economic analysis to determine the market price and quantity. There exist some oscillations to reach the equilibrium point. These oscillations depend on the qualitative and the quantitative response of the suppliers and the customers and estimation of these responses are critical. It is important to estimate the potential of an ILM program to reach the equilibrium point. Updating the incentive rate design with the potential estimates is the crux of devising an ILM program [3].

ii) Market Design

Although most present day interruptible contracts are pre-specified in advance, energy market-place transactions can also allow for more frequent updates like one-hour spot-price, calculated based on system operating conditions and forecasts of how much interruptible energy will be purchased from customers. Customers, who choose to sell interruptible energy, do so by communicating the secure energy level they can offer [4]. Also, in an electricity market some generating companies could offer low cost but rather inflexible units while other may opt for more expensive but highly flexible generation. Even customers could be given the opportunity to offer their ability to reduce their demand during periods of peak prices. This diversity of options helps to clear the market at a lower price.

Therefore, appropriate design of the market where the customers can participate in the ILM programs is very important. The customers may choose to have a direct contract with the ISO or may opt to participate and offer its demand reduction directly in the spot market or in the balance market.

iii) Program Implementation

Once the market for interruptible load has been established, it is important that the market can function efficiently and is fair to all participants. The issues related to implementation of the ILM program would include setting up of the information technology infrastructure to ensure timely information flow from the ISO or the utility to the various ILM participants, the installation of real-time meters at the customer-side to monitor that real-time interruption schedules are fulfilled and payment activities are coordinated.

1.3.3 The Importance of Price-Responsive Demand

It is desirable that the customers should have the opportunity to see electricity prices on a hour-to-hour basis, reflecting market price variations. This will improve the efficiency, increase reliability, and reduce the environmental impacts of electricity production.

Customers who choose to face the volatility of electricity prices can lower their electricity bills as they can modify electricity usage in response to changing prices: i) by increasing usage during low-price periods, and ii) by cutting down usage during high-price periods. Customers who modify their usage in response to price volatility help lower the size of price spikes.

This demand-induced reduction in prices is a powerful way to mitigate the market power that some generators would otherwise have when demand is high and supplies tight. And these price-spike reductions are beneficial to all retail customers, not just those who modify their consumption in response to changing prices [5].

Figure 1-6 shows the hypothetical demand and supply curves. The solid vertical line represents demand that is insensitive to price; the dashed line represents demand that varies with price. For the latter case, the consumers responding to price (*i.e.*, elastic demand) reduce the demand from Q_{inel} to Q_{el} and thus brings about a reduction in the price from P_{inel} to P_{el} (which is quite low if the price elasticity of demand is high).

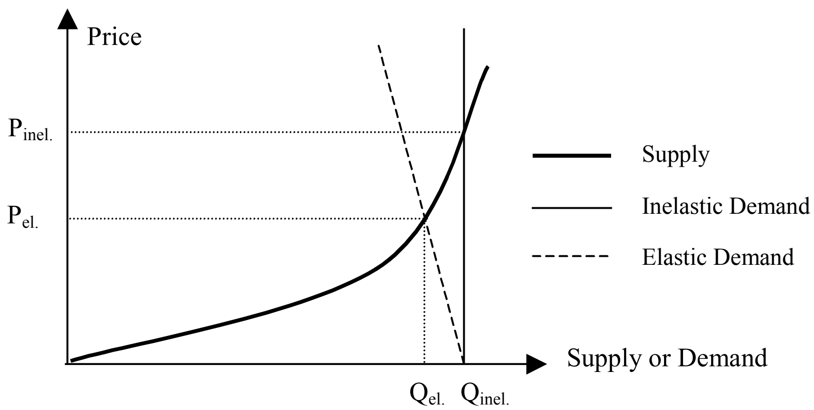

Figure 1-6: Hypothetical demand and supply curve

Customers who face real-time prices and respond to those prices provide valuable reliability services to the local control area. Reference [6] has noted that "to improve the reliability of electricity supply, some or all electric customers will have to be exposed to market prices". Specifically, load reductions at times of high prices (generally caused by tight supplies) provide the same reliability benefits as the same amount of additional generating capacity (but at a lower cost).

Finally, strategically timed demand reductions decrease the need to build new generation and transmission facilities. When demand responds to price, system load factors improve, increasing the utilization of existing generation and reducing the need to build new facilities. Deferring such construction may improve environmental quality. Cutting demand at times of high prices may also encourage the earlier retirement of aging an inefficient generating units.

1.3.4 Interruptible Load versus Demand-side Management

Demand-side management is the planning and implementation of the utility activities designed to influence customer use of electricity in ways that will produce desired *long-term* changes in the utility's load shape. Figure 1-7 shows different load shape objectives of demand-side management program. These include: peak clipping, valley filling, load shifting, strategic conservation, strategic load growth and flexible load shape.

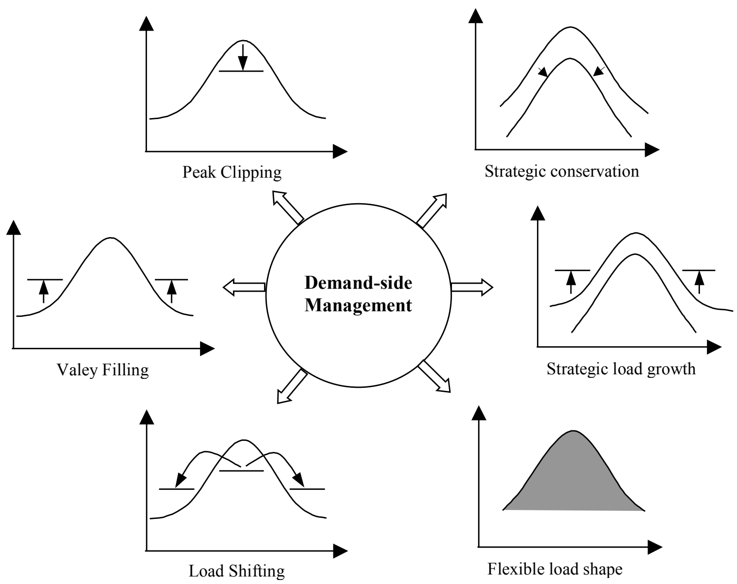

Figure 1-7: Demand-side management objectives [7]

As described in the previous section, interruptible load program is an option within a demand-side management program that provides incentives to customers for reducing their power demand during the system peak load period or emergency conditions.

1.3.5 Interruptible Load versus Fast-Startup Generator

One may ask: "Is there any difference between interrupting a load and putting online a fast-startup generator (FSG)?". There are several differences:

- The interruptible load can be available everywhere in the system, while the FSG can only be installed at limited locations. Hence, interruptible load provides the ISO with a wide range of selection in the network.
- Besides providing active power reduction, interruptible load also provides the system with "free" reactive power relief.
- FSG involves a large capital investment while that for interruptible load is much less. The utilities do, however, have to pay financial incentives to the ILM participants. For a long-term plan, it would require a detailed economic analysis to clearly identify the cheaper option.

- FSG has to run more than a "must-run" hours requirement, while the interruptible load can only be run within some specified hours.

1.4 Objectives of the Thesis

The study presented in this thesis attempts to:

- Provide an understanding of the theoretical and practical aspects of interruptible load management in deregulated system operations;
- Design a market for interruptible load customers who are willing to reduce their demand, as and when requested, in return of a financial compensation;
- Examine the operational roles of interruptible load in cases of contingencies and demand spikes in the system;
- Examine the possibility of interruptible load in providing transmission congestion relief;
- Carry out a cost-benefit analysis of long-term congestion management solution through the investment in reserve generation capacity.

1.4.1 Outline of the Thesis

Chapter 1 provides an overview of the interruptible load management within the context of deregulated electricity market. The importance and rationale for interruptible load services are presented. The objectives of this study toward resolving different existing issues related to operating of the interruptible load management program in the deregulated electricity market are presented

Chapter 2 addresses the importance of operational roles of interruptible load management programs, namely, Direct Load Control; Dynamic Tariff/Pricing; Incentive Compatible Contract; Callable Forwards; Demand-Side Bidding; Specific ILM Markets; Priority Pricing.

Chapter 3 discusses the overall picture of the interruptible load management programs of various electric utilities, electricity markets and independent system operators around the world. The working mechanisms of interruptible load management programs and their effectiveness in aiding system operation in peak load periods and contingencies are discussed.

Chapter 4 develops a model for interruptible load procurements within the secondary reserve ancillary service market based on an optimal power flow (OPF) framework. The model determines the real-time selection of the interruptible load participants. The characteristics of the procurements of interruptible load such as advance notification, locational aspect of the load and power factors of the load, are explicitly considered in the model.

Chapter 5 presents a brief review of the existing congestion management methods in deregulated electricity market. It also illustrates the role of interruptible load as a system service for transmission congestion management through the development of a Congestion Relief Model. The model is able to locationally identify the buses where corrective measures need to be taken for relieving congestion over a particular congested line.

Chapter 6 develops a framework for the evaluation of long-term congestion management solution by the fast-startup gas-turbine generator based on the traditional cost-benefit analysis. This involves a planning exercise to optimally decide the locations and sizes of the gas-turbine generators at different buses in the network such that the total cost of investment on gas-turbine generators and the cost of system congestion is minimized.

Chapter 7 summarizes the main results of the present work and discusses issues for further study in this research area.

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CHAPTER 2
INTERRUPTIBLE LOAD MANAGEMENT IN SYSTEM OPERATIONS

This chapter addresses the importance of operational roles of an interruptible load management (ILM) program, with special emphasis on deregulated electricity markets. ILM programs have been classified into: Direct Load Control; Dynamic Tariff/Pricing; Incentive Compatible Contracts; Callable Forwards; Demand-Side Bidding; Specific ILM Markets; and Priority Pricing Mechanism. These are summarized in Figure 2-1:

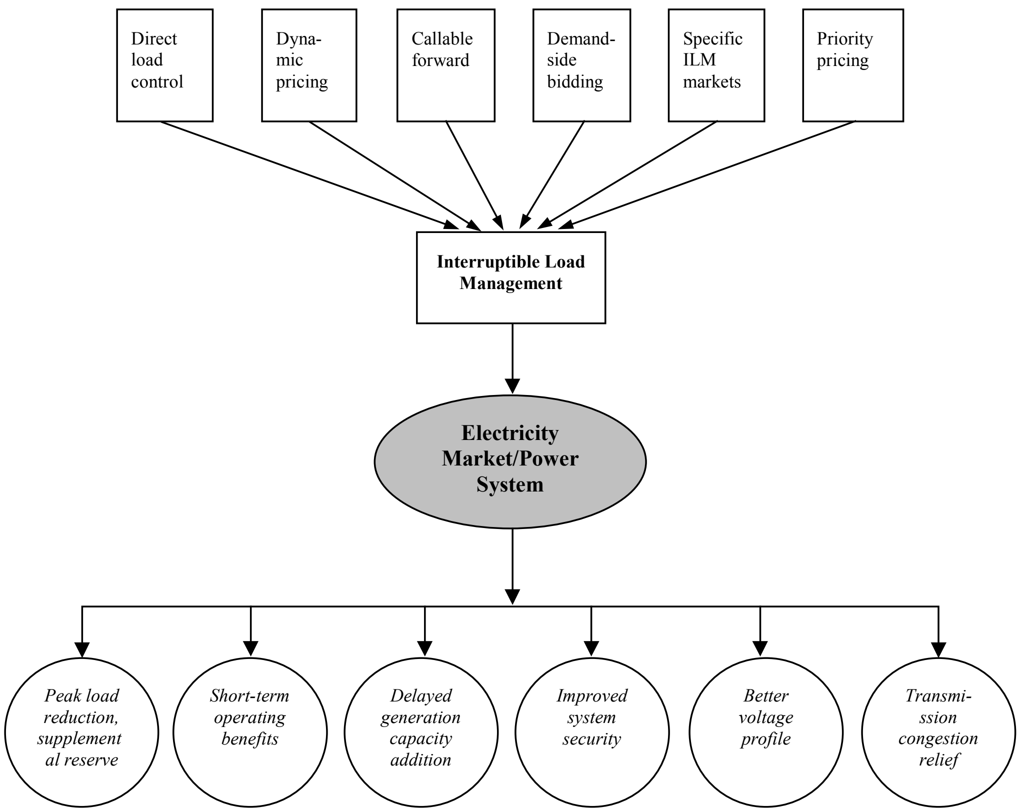

Figure 2-1: Interruptible load management program and its roles in system operations

2.1 Interruptible Load Management in System Operation

In order to be an effective means of managing peak load by the utility/ISO, an ILM program must adequately address the following issues [1]:

1. What are the short-term discounts in prices (in $/MWh) to be offered to the customers participating in the ILM program?
2. What are the longer-term benefits to be given to the customers in terms of reduction in demand charges (in $/MW) for the part of the demand subscribed to ILM?
3. How does the utility select different types of interruptible load in real-time taking into account the following considerations:
   - *advance notification for load curtailment*: one hour, one day, one week.
   - *duration of curtailment*: curtailment limited to peak hour only, or longer period curtailment by shifting load to off-peak hours.
   - *nature of load and cost associated with load curtailment*: low power factor with lower cost of curtailment.
   - *generation and network characteristics*: spatial demand and generating sources, limits on generation output, ramp rate, voltage, or line flows.
   - *system security*: to ensure that the system can "survive" a specified list of contingencies, *i.e.,* the emergency limits on voltage and line flow limits are not exceeded for certain line, bus or generator outage combinations.

A study on system peak demand reduction due to different load control programs in the case of the Taiwan power system was presented by Chen and Leu [2]. The avoided-cost of capacity addition for the utility and appropriate incentive rate structures to the customers were discussed in the paper.

Impact of load management on short-term operating benefit was addressed in [3]. It was shown in the paper that the interruptible load program resulted in great cost saving in terms of reducing the total societal cost (system operating cost and customer interruption cost) of electricity.

The role of interruptible load in providing supplemental operating reserve to the system was studied in [4]-[9], where a number of techniques are presented to include interruptible load in the probabilistic assessment of the level of system operating reserve. An adequate operating reserve is required in an electric power system in order to maintain a desired level of reliability throughout a given period of time. Interruptible load can be considered as part of the system operating reserve if required. The inclusion of interruptible load in the assessment of unit commitment in interconnected systems was demonstrated in [6] and of economic load dispatch of generation systems in [7].

An optimal power flow framework developed by Majumdar *et al.* [1] addressed issues of advance notification for load curtailment as well as short- and long-term price discounts on demand charges. It was shown in [10] that the interruptible tariff mechanism would be able to aid system operation during peak load periods, such as increased reliability margins, improving voltage profiles as well as relieving network congestion. A mathematical model was developed to express the response of customers to incentives offered by the utility and the OPF framework was modified to incorporate various utility-customer interactions while determining the optimal incentives.

Caramanis *et al.* [11] worked out a comprehensive pricing formulation for interruptible loads and assignment of power pool reserves. It was shown that optimal pricing mechanisms did exist, and these invoked customer participation in a socially optimum manner to aid in system operation and provide for system security. Consequently, it was shown by Kaye *et al.* [12] that system security could be maintained in an operating environment where all participants (including those on the supply-side and those on the demand-side) sought to optimize their own benefits through pricing mechanisms. A generalized model for the inclusion of security constraints in competitive markets was developed in [13] where the prices are determined by considering customer demand-price elasticity.

The role of demand elasticity in congestion management and pricing in a competitive electricity market was investigated in [14]. The actions of price responsive loads could be represented in terms of the customers' willingness-to-pay. From each customer's demand curve, the elasticity of the load at different prices is known and the benefit function is derived. The load at each bus ceases to be a fixed quantity and becomes a decision variable in the ISO's optimization problem. In this way, the ISO has additional degrees of freedom in determining necessary actions for network congestion management.

As the electric power industry moved towards deregulation and competition, the generating capacity margins available to the system operators have been reducing drastically. There is an emerging question as to “Who should be responsible for generation capacity addition?”, explicitly addressed in Söder [15], at least for the case of the Swedish deregulated electricity market. It was suggested that one of the possible measures would be to develop a market for voluntary demand reduction, *i.e.,* the interruptible load market, where the customers would be compensated for the costs of electricity service interruption.

2.2 ILM Programs, Mechanisms, and Markets

A number of methods for designing optimal working mechanisms for interruptible load participation has been proposed in the research literature. These can be divided into several groups, namely direct load control, dynamic/interruptible tariff, incentive compatible contracts, callable forwards, demand-side bidding, specific ILM markets, and priority pricing mechanism. We briefly discuss them in the following subsections.

2.2.1 Direct Load Control

The amount of system peak load reduction through scheduling of control periods in commercial/industrial and residential load control programs at Florida Power and Light Company have been calculated using a linear programming (LP) optimization model [16]. The LP model can be used to determine both long- and short-term control scheduling strategies and for planning the number of customers that should be enrolled in each program. Similarly, a profit-based load management program was introduced in [17] to examine generic direct load control scheduling. Based upon the cost/market-price function, the approach aims to increase the profit of utilities. Instead of determining the amount of energy to be deferred or to be paid back, the algorithm controls the number of groups per customer/load type to maximize the profit.

The direct load control problem of air conditioner loads (ACLs) was addressed using a fuzzy dynamic programming approach developed in [18]. The interrupted capacities of the ACLs and the system load demands are all regarded as fuzzy variables. The scheduling of directly controlled loads and the unit commitment are integrated into the fuzzy dynamic programming structure to reduce the system peak load as well as total operating costs. Genetic algorithm has been applied to scheduling of direct load controls in [19]. The control strategy (or scheduling) arranged by the recursive genetic algorithm not only sheds the load so that the load required to be shed at each sampling interval is individually satisfied, but also minimizes the load shed in order to minimize the utility's revenue loss due to direct load control.

2.2.2 Dynamic Tariff/Pricing

Among some works on interruptible load and tariffs, the need and the role of dynamic pricing options in achieving utility demand management objectives with reference to some of the existing interruptible load management options in different countries were discussed by Shangvi [20].

A consumer behavior model was proposed by David *et al.* [21], [22], incorporating demand elasticity across time, degree of consumer rationality and the supply-side information, and information on the price formation model. The behavior model serves as load management tools as it could help to predict how consumers would respond to the magnitude and variation of electricity price.

Spot pricing of electricity embodies a unified approach to multiple goals of demand-side management by reflecting the time varying nature of the cost of electricity supply. The customer's response to spot prices was discussed in [23], [24]. The attributes that enabled flexible customer response without service curtailments were identified and optimal behavior of industrial customers under spot pricing mechanism was examined in [23]. It also showed that there would be a potential for cost savings associated with spot pricing as compared to those associated with flat rate pricing. An integrated theory of consumer response models and system price forecasting under dynamic conditions created by dynamic pricing was introduced in [24].

Different structures of ILM programs and their effects on system peak demand reduction in the case of Taiwan power system were presented in [2]. Three alternative incentive rates based on avoided-cost were designed for interruptible load programs. Among these, one was actually activated by Taiwan Power Company (Taipower) in 1987, when some preliminary results were obtained.

The design of the optimal interruptible load contract was attempted in [25] by using the mechanism design. It was shown that the so designed contract would give the customers enough incentive to sign up voluntarily for the right contract and reveal their true value of power. The paper suggested that it would not be necessary for a utility to know in advance the type of customer it faced when designing such programs. The paper illustrated and incorporated the importance of load location into the process. Another paper of similar nature [26] attempted to formulate various incentive-responsive demand management programs considering social (utility and customer) optimality, which could help electric utilities to reduce transmission bottlenecks and increase the safety margin of power systems.

It was shown in [27] that the available data on current demand management contracts could be used to calibrate the customer cost function and help design better demand management contracts. It was also shown that the key to have efficient demand management contracts would be by having a good estimate of the customer outage cost function. If the estimated cost function is correct, utilities can optimize the compensation they offer in return for load curtailment.

2.2.3 Callable Forwards

In the context of deregulation, a market for interruptible load (callable forwards), which is continuously tradable until the time of use, was proposed by Gedra and Varaiya [28]. The equivalence between interruptible service contracts and forward contracts bundled with a call option was discussed in detail. In a competitive market, customers wishing to ensure a fixed electricity price while taking advantage of their flexibility to curtail loads can do so by purchasing a forward electricity contract bundled with a financial option that provides a hedge against price risk and reflects the real options available to the customers. This financial instrument was referred to as a double-call option [29]. It was shown that a forward contract bundled with an appropriate double-call option would provide a perfect hedge for customers that could curtail loads in response to high spot prices and could mitigate their curtailment losses when the curtailment decision was made with sufficient lead-time.

2.2.4 Demand-Side Bidding (DSB)

A framework for the incorporation of demand-side participation in a competitive electricity market was introduced by Strabac *et al.* [30]. This framework can be used for comprehensive evaluation of possible scenarios for the implementation of DSB into the electricity market as well as for the assessment of the influence of DSB on total production costs, system marginal price, capacity payment, *etc*.

It was argued in [31] that in a competitive electricity pool, highly flexible forms of generation and load reduction could cause sharp and unwarranted increases in electricity prices if the production schedule would be based on minimization of the total scheduled costs. Such pools are therefore vulnerable to price manipulations by generating companies owning a portfolio of generating units or controlling some demand-side bidding. It was also argued that the competitiveness of demand-side bidding would be artificially inflated if the load recovery periods, which invariably accompany load reductions, were not taken into consideration when establishing the generation schedule.

The behavior of DSB auctions in the power pool framework, using the 24-hour unit commitment model, in which both supply and demand bids are equally treated, was studied in [32]. The customers are allowed to participate in the market by submitting the bid for the reduction in their demand during the system peak periods or during times of contingencies. The market prices are determined at the point where the aggregate supply bids and demand bids intersect. The model also takes into account the load recovery characteristics after the interruption. It was shown that DSB would be able to mitigate the potential for exercise of market power by the supply-side bidders and DSB would help smoothen the system marginal prices and mitigate price volatility.

A method to build optimal bidding strategies for both power suppliers and large customers in a pool-co type electricity market was presented in [33] using a stochastic optimization model. It is assumed in the paper that each supplier/customer bids a linear supply/demand function, and the system is dispatched to maximize the social welfare. Each supplier/customer chooses the coefficients in the linear supply/demand function to maximize benefits, subject to expectations about how rival participants will bid.

2.2.5 Specific ILM Markets

It was suggested by Hirst and Kirby [34] that electric customers, *i.e.,* the load, would participate directly in the wholesale competitive market to improve economic efficiency, increase reliability and reduce environmental impacts of electricity production. It was also suggested that, ultimately, competitive electricity markets would feature two kinds of demand-response programs. First, some customers would choose to face electricity prices that vary from hour to hour. Typically, these prices will be established in the day-ahead markets run by regional transmission organizations. Second, some customers would select fixed prices, as they had in the past, but voluntarily cut demand during periods of very high prices. In the second option, the customer and the electricity supplier would share the savings associated with such load reductions.

In deregulated electricity markets, the ISO has an overall responsibility of providing and procuring various services that are essential for the maintenance of system security and reliability. Such services have been referred to as ancillary services. According to the North America Electricity Reliability Council (NERC) Operating Policy-10 [35], interruptible load management (ILM) is recognized as one of the contingency reserve services. Similarly, the Australian electricity market recognizes "load shedding", both as a frequency control service and a network loading control ancillary service [36]. The Swedish ISO (Svenska Krafnät) also recognizes ILM as an ancillary service, though there is no established financial compensation scheme in place yet. Interruptible load can participate in the reserve markets and it was shown in [5] that it would have the same net effect as reserve generation, that they provide a means of maintaining the balance of supply and demand in the event of a failure in the system. It was shown by Kirby and Hirst [37] that load would be considered as a resource in providing ancillary services. In [38], the design of a market for interruptible loads within the secondary reserve ancillary service was proposed and proved to function well. The locational aspect of interruptible load offers was incorporated in the market operation through marginal loss coefficients at every load bus. The paper also attempted to incorporate the behavior of the interruptible load offers with respect to the information on system operating reserve forecast.

2.2.6 Priority Pricing Mechanism

Priority pricing of interruptible electric service induces each customer to self-select a rationing priority that matches the order of its interruption loss. A tariff structure (with subject to minimization of total expected customers interruption cost) proposed in [39] allowed a customer to choose either early notification and pay a fixed fee, or select no advance notification along with a level of compensation when interrupted. The chosen compensation determines customer service priority and corresponding price.

In the event of shortage in generating capacity, it is obviously inefficient if the electricity utility cuts off customers randomly. It is preferable to set up a market in service priority in which customers who have a greater need pay more for the right not to be cut off. An econometric model of outage costs in Israel was used to calculate the menu of priority rates by season and time of day. Top priority rates range from zero, when the loss-of-load probability (LOLP) is zero, to 8 cents (US) per kWh when the LOLP is highest [40].

2.3 Concluding Remarks

This chapter presents a systematic review on recent research trends in the issues related to interruptible load management. It should be noted that depending on the structure of the electricity market and the perception of the customer, appropriate interruptible load contracts must be designed to attract customer's participation in ILM schemes so as to maximize the overall economic efficiency. It has been shown that ILM would be a cost-saving opportunity for the peak load capacity problem, especially in the deregulated electricity markets.

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CHAPTER 3

INTERRUPTIBLE LOAD MANAGEMENT: A GLOBAL PICTURE

International experiences on ILM practiced by various electric utilities, electricity markets, independent system operators (ISOs) around the world (i.e., Alberta, England and Wales, California, Australia, New York, New Zealand, Sweden and Taiwan) are presented. The working mechanisms of ILM as implemented by those utilities/markets and their effectiveness in aiding system operation in peak load periods and contingencies are discussed.

3.1 Alberta Power Pool

The Alberta power pool in Canada has a curtailable load program so as to enhance the system security of the Alberta Interconnected Electric System operations. Customers willing to participate in the program need to offer at least 1MW of their load as curtailable load. There is also a requirement for time-of-use metering equipment and the customer's ability to receive dispatch instructions from the pool when required. Customers need to submit their offers in terms of the curtailable MW and the associated price. Based on the offers received by the pool, the pool operator determines the contracted curtailable customers, by classifying them either as Type-1 or Type-2. The details of these two Types are summarized in the Table 3-1.

Table 3-1: Curtailable load program - Alberta [1]

Name	Contract type	Advance notification	Minimum curtailment	Payment structure
Type-1	1-month contract	1 hour	1 MW, up to 4 hours	fixed price per MW per month independent of the number of interruptions requested
Type-2	weekly contract	1 hour	1 MW, up to 4 hours	price per MWh and suppliers are paid only when they are dispatched.

Offers are ranked in order of their prices, from lowest to highest. The pool operator selects the offers starting from the lowest price till it meets the curtailment quantity requirement.

3.2 Demand Relief Program of California ISO (Cal-ISO)

Cal-ISO has initiated a demand relief program (DRP) in which the customer signs a contract with the ISO for its demand reduction. The ISO implements the program as a means of providing incentives to induce customers to reduce their demand during times of resource shortage. The payments are based on monthly capacity reservation, which is preset by the ISO, and then there are payments for the energy actually disconnected. The customer must be able to reduce at least 1 MW of load demand. The ISO and contracted load enters into the contract. The contracts are different for loads with and without backup generators (BUG). The summary of the contract types is shown in Table 3-2.

Table 3-2: Demand relief program - Cal-ISO [2]

Name	Contract type	Advance notification	Minimum curtailment	When called upon	Payment structure
Without BUG	offer for interruption	call first, 30 minutes	1 MW, up to 4 hours	emergency reserve less than 5%	- monthly capacity reservation payment - payment for energy actually disconnected
With BUG	offer for interruption	call second, 15 minutes	1 MW, up to 4 hours	emergency reserve less than 2%	

According to an evaluation of the DRP in 2000 [3], 269 MW of loads was received and evaluated. The average capacity price for the accepted offers to the DRP was about $36,000 per MW-month. The average energy price was $226 per MWh.

3.3 Demand-side Bidding Mechanism in the UK

Within the trading arrangements of the UK power pool, demand-side bidding was introduced in December 1993 and has since then operated as a demand reduction scheme. In this way, the demand-side bidders are deemed to have a more beneficial effect by reducing demand by a pre-defined amount rather than by an unknown amount. The participants must offer at least 10 MW of their load for curtailment and have a potential for 50 GWh demand reduction over a year. Demand-side bidders are expected to abide by the demand reduction schedules, or if no schedule is received, when the system marginal price is equal or higher than the bid price of the relevant reducible demand.

The payment structure for demand-side bidding is as follows:

- Demand-side bidders pay at Pool Selling Price for all demand actually taken, independent of whether it was offered as being reducible.
- Demand-side bidders receives an Availability Payment, when there is a value, for all demand offered available for reduction, that is not scheduled in the unconstrained schedule.

The intent behind the scheme is to schedule, when cost-efficient, any demand reduction submitted by participants as available for reduction in a similar manner as generating units. The scheme is implemented as follows: The demand-side bidders bid within their fully expected demand for each half-hour of the next day, offer reducible availability, which is the demand available for reduction and the market price above which, the demand will be reduced. The pool operator resolves the market incorporating the demand bids that are scheduled in the unconstrained market settlement in the same manner as scheduling a generating unit. Within one hour of the publication of the system marginal price, the demand-side bidder will receive notification of demand reduction scheduled for the next day. In the event that there is no demand scheduled for reduction, then whenever the value of the marginal price equals or exceeds the bid price, participants are required to reduce demand [4].

3.4 NEMMCO (Australia)

The National Electricity Market Management Company (NEMMCO), which is the ISO in Australia, allows for demand-side bidding in the market. However the rules and codes are not very attractive to the customers. So far, only a few large customers and pump-storage hydro power plants are participating. Customers can register as scheduled loads and can submit their dispatch bids to the NEMMCO. Both generators and customers are centrally dispatched. The dispatch bid can be specified so as to increase or decrease the load if the price is below or above the pre-specified level. The Australian National Electricity Code Administration is taking initiatives to change the rules to introduce more attractive arrangements for demand side bidding [5].

3.5 New York ISO

There is a provision for customers to offer interruptible load service to a Load Serving Entity (LSE) within the New York ISO (NYISO) and thereby provide additional operating reserve to the latter. They may enter into contracts with LSE for compensation. But in order to participate in the day-ahead or operating reserve market, customers must contract their interruptible load with NYISO directly, thereby allowing direct control, monitoring and billing by the latter. The offers must be larger than 1MW, the response time must be less than 10 minutes and the duration can be up to 1 hour. Interruptible loads are classified into several types:

- *With non-price capped fixed energy:* Load that schedules non-price sensitive energy (*i.e.* a fixed MWh level with no price cap), and then offers to interrupt that load to reduce the demand
- *With price-capped energy:* Load that schedules day-ahead price-sensitive energy, and then offers to interrupt that load to reduce the demand.

There is a provision for 10-minute and 30-minute spinning reserve markets in NYISO wherein interruptible and/or dispatchable load resources located within the NYISO and synchronized to the system can offer to participate. In such cases, they would need to respond to the ISO instructions for load curtailment within 10-minute or 30-minute time-frames, as applicable. The offers in these markets can be for 2 MW or 1 MW of synchronized load at each hour and the NYISO schedules for both 2 MW load and 1 MW 10-minute spinning reserve for each hour. The 2 MW loads are paid for each hour at day-ahead energy price while the 1 MW loads are paid the 10-minute spinning reserve market-clearing price for each hour [6], [7].

3.6 New Zealand - The M-Co

M-co was formed in 1993 as EMCO (the Electricity Market Company) specifically to develop, implement and operate New Zealand's wholesale market for trading electricity. Today, M-co remains at the forefront of positive change within that industry, and continues to increase efficiency and reduce transaction costs for electricity industry participants.

New Zealand Electricity Market (NZEM) was established as a market for both purchasers and generators. However, market participants have identified that more can be done to deliver the purchaser, or demand-side, participation to its fullest potential.

The Demand-side Participation sub-group of the Market Pricing Working Group (MPWG) examined which areas of NZEM could further enhance the accuracy and economic efficiency of the price signal. The group believes this will improve the prospects of demand side participation.

Demand-side bidding is allowed in the market by the market settlement rules. However, only some embedded generators are bidding in the market. Recently the Market Pricing Working Group has proposed some recommendations to promote demand-side bidding [8]:

- Appropriate and timely price signals are a key to demand side participation
- Self-dispatch in response to price signals is the most appropriate means of encouraging efficient demand-side participation
- Demand-side should have greater freedom to self-dispatch in response to a price signal
- Final price should be published as close as possible to real time, as widely as possible
- Lowering fixed fees in NZEM to encourage a higher level of direct demand side membership

3.7 Sweden

Since 1 January 1996, Svenska Kraftnät has been designated as the authority with system responsibility. By law, Svenska Kraftnät has been given the power to issue direct orders to producers to increase and decrease production rapidly in order to keep the balance of the system. Svenska Kraftnät can also issue orders to decrease electricity consumption. It has also been given the right to stipulate the technical requirements and the reliability requirements for production plants and networks.

Svenska Kraftnät is responsible for metering and final settlement at the national grid level. All electricity supply companies have to be connected to the system of metering and final settlement for balancing by Svenska Kraftnät. Svenska Kraftnät has also been designated as the exclusive grid-responsible entity in Sweden according to the Transit Directive [9].

In Sweden, interruptible load management is considered as an important solution for the peak load capacity shortage problem. Swedish ISO (Svenska Kraftnät) as well as other energy authorities are trying to find the optimal mechanism to allow/encourage the customers to participate in the spot market for the change in their electricity demand. The ISO encourages suppliers and customers to reach mutual agreements on how to enable the interruptible load program. The objective is to bring the interruptible load into the market. The ISO recently signed an interruptible load contract with one big industry as part of its ancillary services. As it stands, the spot market in Sweden (Nordpool) is of double-auction type and could well fit in interruptible load offers (or demand-side bidding) [10].

3.8 Taiwan

Taiwan Power Company (Taipower) is a state-owned utility company and provides the electricity in Taiwan. With high load growth and delays in new generation capacity addition due to environmental regulations, the system spinning reserve has been reduced to a low level. Load sheddings had to be implemented when a large unit tripped during the summer peak period and a significant economic loss was incurred [11].

Taipower has successfully implemented an interruptible load control program, as shown in Table 3-3.

Table 3-3: Interruptible load programs - Taipower

Name	Contract type	Advance notifica-tion	Minimum curtailment	Payment structure
Strategy A	contract	1 day, 1 week	industrial customers, 5 MW, 6 hours per day	contracted demand is charged with 50% discount price
Strategy B	contract	1 day, 4 hours, 1 hour	all industrial customers, up to 6 hours per interruption, less than 100 hours a year	depending on advance notification time

Note: Strategy A was actually implemented in 1987

The results showed that with the strategy A, customers participated in the program and reduced the system peak load significantly. The system peak was decreased by 2.44% of the total peak demand. The potential effect of ILM with strategy B was also investigated [11]. It showed that there would be a dramatic increase of potential for interruptible load service if the discount rate was increased from 30% to 50%, and more peak load reduction would be exercised if the advance notification time was increased.

3.9 Summary and Concluding Remarks

This chapter presents an overview of how interruptible load management schemes have been working in some of the deregulated electricity markets around the world. A summary of these schemes is presented in Table 3-4.

It can be seen from Table 3-4 that in all the systems discussed, ILM has either been a direct contract with the ISO/load serving entity or direct bidding into the pool market. In the case of New York ISO, the ILM can also participate in the 10-minute spinning reserve market. The advance notification time required varies from 10 minutes to 1 day. The incentive schemes include reduced electricity price; fixed payment per MW per month; and price per MWh of energy actually disconnected.

It should be noted that depending on the structure of the electricity market and the perception of customer, appropriate interruptible load contracts must be designed to attract customer's participation in ILM scheme to maximize the overall economic efficiency. It is realized that in some markets, ILM has been successfully implemented, while in other markets, it is still in development phase. Similar to our conclusions from the previous chapter, the review of utility practices have also shown that ILM would be a cost-saving opportunity for the peak load capacity problem, especially in the deregulated electricity markets.

Table 3-4: Interruptible load programs in selected markets: A summary

Name	Contract type	Advance notification	Minimum curtailment	Payment structure
Alberta				
Type-1	1 month contract	1 hour	1 MW, up to 4 hours	fixed price per MW per month independent of the number of interruptions requested
Type-2	weekly contract	1 hour	1 MW, up to 4 hours	price per MWh and suppliers are paid only when they are dispatched
Cal-ISO				
With BUG		Call second, 15 minutes	1 MW, up to 4 hours	- monthly capacity reservation payment - payment for energy actually delivered
Without BUG		Call first, 30 minutes	1 MW, up to 4 hours	
United Kingdom	bid in pool	1 day	10 MW, 50 GWh per year	- pay pool selling price - paid availability payment
Australia	bid in pool	1 day	large customers	not yet developed
New York	contract	10 minute	1 MW and 2 MW, up to 1 hour	1 MW paid 10-minute spinning reserve market price 2 MW paid day-ahead market clearing price
New Zealand	under develop-ment	under development	under development	under development
Sweden	under develop-ment	under development	under development	under development
Taiwan				
Strategy A	contract	1 day, 1 week	5 MW, 6 hours per day	contracted demand is charged with 50% discount price
Strategy B	contract	1 day, 4 hours, 1 hours	all industrial customers, up to 6 hours per interruption	depending on advance notification time

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CHAPTER 4

THE DESIGN OF INTERRUPTIBLE LOAD SERVICE MARKETS

This chapter focuses on optimal procurement of interruptible load services within the secondary reserve ancillary service market in deregulated power systems. The proposed model is based on an optimal power flow framework which could determine the real-time selection of the interruptible load offers by the Independent System Operator (ISO). The structure of the market is also proposed for implementation. Various issues associated with procurement of interruptible load such as advance notification, locational aspect of the loads, power factor of the loads are explicitly considered. It is shown that interruptible load management would considerably help the ISO to maintain the system operating reserve during the peak load periods. The CIGRE 32-Bus system, modified to represent different customer characteristics is used for the study.

4.1 Introduction

As described in Chapter 3, in deregulated electricity markets, the ISO has the overall responsibility of providing and procuring various services that are essential for the maintenance of system security and reliability. Such services are referred to as *ancillary services*. According to the North America Electricity Reliability Council (NERC) Operating Policy-10 [1], interruptible load management (ILM) is recognized as one of the contingency reserve services. Similarly, the Australian electricity market recognizes "load shedding", both as a frequency control service and a network loading control ancillary service [2]. The Swedish ISO (Svenska Krafnät) also recognizes ILM as an ancillary service and is in the process of establishing a proper framework for its functioning.

We have also seen from our reviews in Chapters 2 and 3 that it has been generally accepted that ILM has an important role to play as system ancillary services, particularly as contingency reserve services. It is more so, since the operating margins available to the ISO have been reducing drastically with increasing market competition.

Contrary to pool markets, where generation sell offers and customers buy bids are treated simultaneously within the scheduling program by the pool operator, bilateral contract dominated markets have a different scenario. In bilateral contract dominated markets, the ISO has no say over generation scheduling or unit commitment decisions (for example, Sweden). The generating companies can enter into direct contracts with customers that can be days, weeks, or even months in advance. The ISO is only informed about these transactions to take place on a given day and hour. It is the responsibility of the ISO to meet these transactions while satisfying system constraints. In such markets, interruptible load options are therefore required to be handled by the ISO independently as an ancillary service.

This chapter seeks to examine the role of interruptible loads in enhancing system security in bilateral contract dominated markets. A market structure for interruptible loads has been developed, by introducing a bidding framework for customers willing to participate in this scheme. Based on the available offers, the ISO formulates optimal contracts for interruptible load.

Ideally, the ISO's objective while formulating the optimal contracts would be to seek those customers with the lowest priced offers. However, such a selection may give rise to other complications, such as transmission congestion, increased system losses, increased reactive support requirements, *etc*.

This may happen since choosing to interrupt a low-priced offer from a customer, located at a remote area may increase the system power flows in an undesirable manner. A location-dependent parameter to re-value the customer price offers is introduced in this chapter. Based on the re-valuation of price offers, the ISO can obtain the optimal interruptible load contracts that satisfy all system constraints.

An optimal power flow (OPF) based framework has been used to model the above features of the interruptible load market, customers offers, locational aspects in their offers and the final optimal contracting decisions of the ISO. The OPF model is suitably modified to incorporate the above aspects, while also satisfying the usual system constraints such as bus voltage limits, reactive power support limits, *etc*. A schematic diagram of the proposed interruptible load market structure operated by the ISO is shown is Figure 4-1.

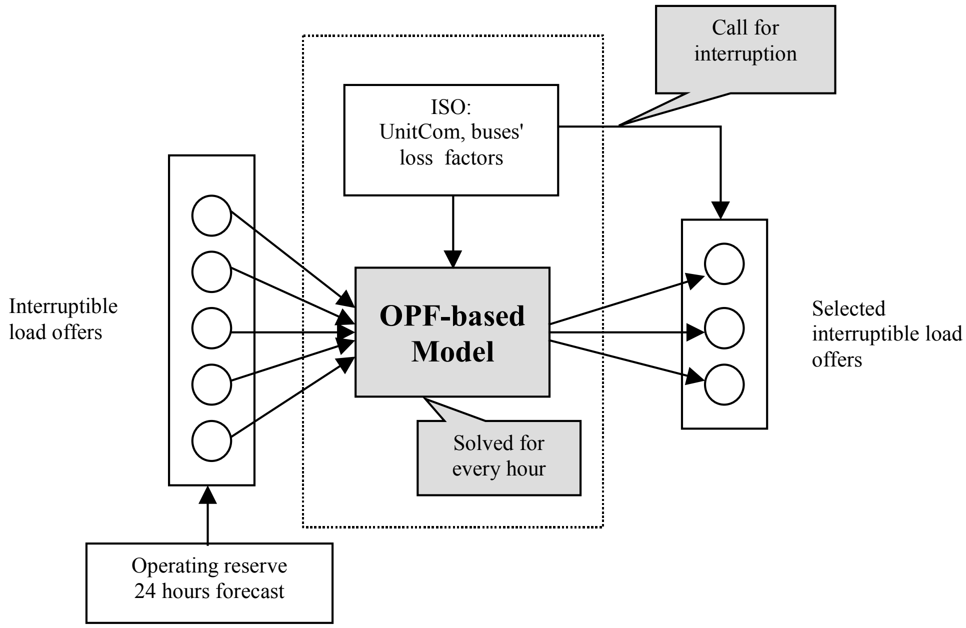

Figure 4-1: Schematic representation of the interruptible load market structure

4.2 Design of Interruptible Load Service Market

It is proposed that the ISO will be fully responsible for the operation of the interruptible load market and would call for offers for load interruption on an hour-to-hour basis. Unit commitment schedules of all generators and the calculated loss factors at each bus are assumed available with the ISO.

The interruptible load market participants will submit their offers, specifying the price β (in $/MWh) for energy to be interrupted and the quantity of interruptible load μ (in MW) on an hour-to-hour basis. Figure 4-2 shows the representation of the proposed interruptible load market in the time-domain. It is proposed that the interruptible load providers submit the offers to the ISO at the previous hour (hour *k-1*), for hour *k*. The ISO will evaluate the interruptible load offers and make the optimal selection of interruptible load as per its requirement and that is when the interruptible load market is cleared. The selected interruptible loads are expected to be called upon, as necessary, in the next hour (*i.e.,* between hour *k* and hour *k+1*).

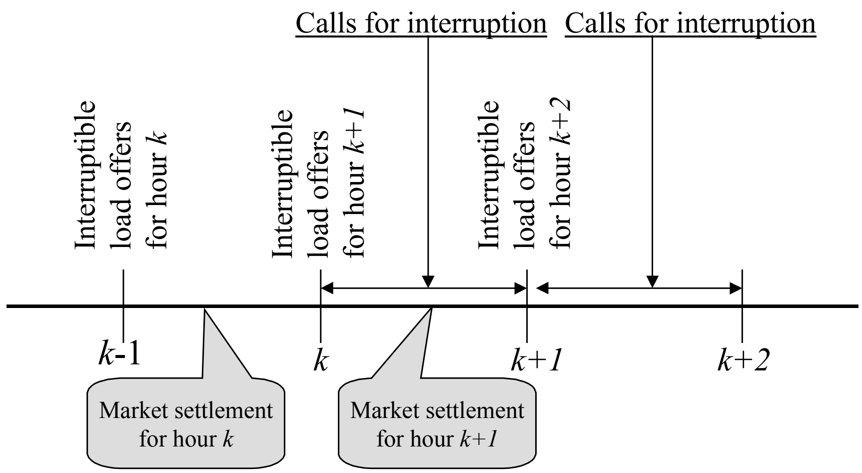

Figure 4-2: Time-frame of interruptible load market

4.2.1 The Structure of Interruptible Load Offers

Since the interruptible load market is proposed to function as an hour-ahead market, the participants can be expected to have information on next hours demand (and hence reserve) forecast, transmission capacity limits across the borders and outage conditions on the system, made available by the ISO.

It is natural that interruptible load offer prices will be sensitive to the available operating reserve information for the next hour (which in this paper is considered to be the *generation reserve*, and is the total committed capacity net of generation). It can be expected that with a very low reserve forecast for an hour, the interruptible load offer prices would be very high.

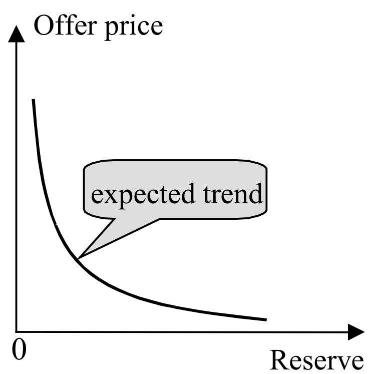

Figure 4-3: Expected bidding behaviors of interruptible load market participants

In Figure 4-3, we formulated a typically expected offer price behaviors as functions of operating reserve. However, determining the exact functional form for such a behavior as shown in Figure 4-3 would be very difficult to assume *a priori*. For the sake of simplicity, we model this bidding behavior of interruptible load market participants using a linear function, as shown in Figure 4-4. From this figure, it is apparent that the interruptible load offer-prices would linearly increase with a decrease in operating reserve. Further, we also incorporate an upper limit on operating reserves, RLIM, above which interruptible load would not be required by the ISO. This restricts the interruptible load market functioning to address critical system conditions only.

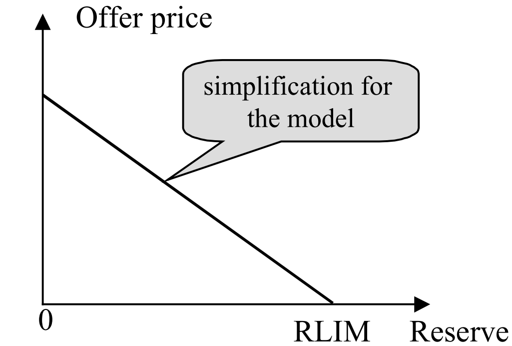

Figure 4-4: Simplified bidding behaviors of interruptible load market participants

Accordingly, from Figure 4-4, the bid-price β can be given as:

$$\beta_i = \beta o_i (1 - R / RLIM) \quad \forall i = 1,...,NILM, \text{ when } R \le RLIM$$
$$\beta_i = 0 \quad \forall i = 1,...,NILM, \text{ when } R \ge RLIM \text{ (no interruption)} \qquad (1)$$

where, R is the operating reserve level.

4.3 Optimum Procurement of Interruptible Load Contracts

The ISO should select the interruptible load offers such that:

- The system loss is minimized;
- Total secondary reserve service cost – SRC (which is defined as total payment to interruptible load customers less the benefits accrued from interruptible load) is minimized;
- ISO requirement on operating reserve is satisfied;

- All system operating constraints are within their limits.

The optimal interruptible load contracts will be based on selected offers, specifying the interruption called for, from each customer type at each hour in real-time. Each selected contract will be paid the uniform price, which is the highest accepted offer price.

In order to do that, the ISO has to execute two consecutive optimization models for every hour in a day as shown in Figure 4-5:

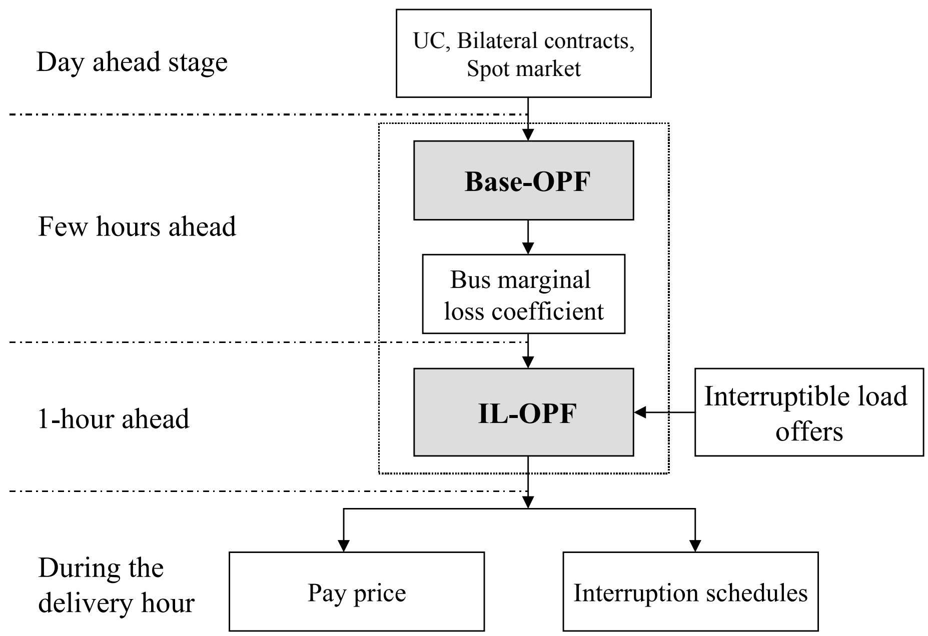

Figure 4-5: Working scheme of interruptible load market

- The Base-OPF model with the objective of minimization of total system losses. The Base-OPF will determine the marginal loss coefficient λ at each load bus. The value of λ denotes the change in system losses due to a unit change in load at a bus. This parameter can be used by the ISO to re-value the bid-price offers. A high bid-priced offer for interruptible load at a bus with significantly high and positive λ could be a better option if the value of loss reduction from that interruptible load is accounted for.

- The IL-OPF model, which is a modified version of Base-OPF, includes the interruptible load offers characteristics as discussed earlier. The objective is to minimize the total payment by the ISO to the selected interruptible load offers. The λ's calculated from the Base-OPF model are used in the objective function of the IL-OPF model. The model determines the uniform price to be paid to all selected interruptible load contracts and the total amount of load to be interrupted for each selected offer during the next hour.

4.3.1 The Base-OPF Model

Objective Function: The ISO's objective is to minimize total system loss during an hour:

$$L = 0.5\sum_i \sum_j G_{i,j}\left(V_i^2 + V_j^2 - 2V_i.V_j \cos(\delta_j - \delta_i)\right) \tag{2}$$

Load Flow Equations: These are modified to include the load interruption ΔPD as requested by the ISO from the interruptible load participants:

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} = \sum_{j,\, j\neq slack} |V_i||V_j|Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{3}$$

$$QG_i - QD_i + \sum_{Type} \Delta QD_{i,Type} + QC_i = -\sum_{j,\, j\neq \mathrm{slack}} |V_i||V_j|Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{4}$$

$$\sum_{Type} \Delta QD_{i,type} = \tan(\cos^{-1}(PF_{Type}))\Delta PD_{i,Type} \tag{5}$$

It is noted that the generation and demand in the system is accounted for in (3) by two different sources/sinks as the case may be. For example, we assume a generator *'i'* is producing an amount $PG_{i,b}$ to meets its bilateral contracts and an amount $PG_{i,m}$ to sell in the spot market. Similarly, the load at bus *'i'* comprises a part $PD_{i,b}$ that is fixed through bilateral contracts and a part $PD_{i,m}$ that is purchased in the spot market. This kind of representation of the generation and load balance is typical of the Swedish/Nordic system which are dominated by bilateral contracts, while also having a participation in the spot market.

The bilateral contracts have been modeled using the principle of "column rule" and "row rule" and have been explained in detail in Appendix 1.

Upper and Lower Limits on Buses Voltages:

$$\begin{aligned} &\left|V_i\right| = \text{constant}, \quad \forall i = 1,\ldots,NG \\ &V_i^{\min} \le \left|V_i\right| \le V_i^{\max}, \quad \forall i = 1,\ldots,NL \end{aligned} \tag{6}$$

Upper and Lower Limits on Reactive Power Support:

$$QC_i^{\min} \le \left|QC_i\right| \le QC_i^{\max}, \quad \forall i = 1,\ldots,NL \tag{7}$$

The Base-OPF described above model remains a nonlinear programming problem and is solved using the GAMS/MINOS solver [3].

4.3.2 The IL-OPF Model

Objective Function: The objective is to minimize the secondary reserve service cost for each hour:

$$\Pi = \sum_i \sum_{Type} \left(\rho.\Delta PD_{i,type} - CL.\lambda_i.\Delta PD_{i,Type}\right) \tag{8}$$

The first component in (8) denotes the total payment made to interruptible load customers selected for interruption. Note that ρ is the uniform interruptible load price that is determined from the model and is payable to all selected interruptible load offers invoked. The second component is the value of loss reduction accrued from the reduction in power demand at a bus and is calculated using the bus marginal loss coefficient (λ), obtained from Base-OPF.

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory level of operating reserve is maintained at all time:

$$\sum_i^{NG} PG_i^{\max}.UC_i - \sum_i^{NL} PD_i + \sum_i^{NILM} \sum_{Type} \Delta PD_{i,Type} \le R \tag{9}$$

Limit on Interruption: Each interruptible load offer is represented in the model by a binary integer variable. The actual interruption invoked by the ISO is limited by the offered quantity:

$$\Delta PD_{i,Type} \leq \mu_{i,Type}.U_{i,Type} \qquad \forall i = 1,..., NILM \tag{10}$$

Further, the quantity offered by an interruptible load market participant is limited by the total demand at its disposal:

$$\mu_{i,Type} \leq a_0.PDem_{i,Type} \qquad \forall i = 1,..., NILM \tag{11}$$

where, a_0 is a scalar, $0<a_0< 1$, which determines how much of the demand that could be made available for curtailment by the interruptible load market participant without causing any economic loss to itself.

Market Settlement: It is proposed that the interruptible load market settlement is a non-discriminating auction where all selected offers are paid the same price (ISO pay-price), which is the highest accepted offer price. The ISO pay-price is determined through the model using the following inequality constraint:

$$\rho \geq U_{i,Type}.\beta_{i,Type} \qquad \forall i = 1,..., NILM \tag{12}$$

Other constraints: Other constraints in the model remain the same as those of the Base-OPF.

The IL-OPF model, as described above, is a mixed integer nonlinear programming problem and is solved using the GAMS/DICOPT solver [3].

4.4 Simulation Studies and Discussions

4.4.1 System Description

The CIGRE-32 bus system, which approximately represents the Swedish grid, has been used for the simulation studies [4]. The system configuration as well as other associated information is provided in Appendix 2.

The hourly load variation at a bus is accounted for by applying a load scaling factor (LSF) at each hour. The load at each hour *h* will be calculated by:

$$PD_i^h = PD_i.LSF^h \tag{13}$$

All buses are classified into three categories: industrial, commercial and agricultural. At each load bus, the load share (LS) of each customer type is simulated by a uniform random number generator. Using these LS values, the customer-wise load a bus is determined by:

$$PDem_{i,Type} = PD_i \, .LS_{i,Type} \tag{14}$$

The load power factors (PF) of various customer type are assumed as follows:
$PF_{Industrial} = 0.95$; $PF_{Commercial} = 0.7$; $PF_{Agricultural} = 0.8$

4.4.2 Simulation Studies

The models described in Sections 4.3.1 and 4.3.2; and the system described in Section 4.4.1 are used to carry out case studies to examine the operation of the interruptible load market and its role in aiding system operations during contingencies. The following cases are constructed:

- *Case 1:* Base ILM case
- *Case 2:* Base ILM case + loss of one large generator (1000 MW) during peak period, during 5.00 PM - 9.00 PM
- *Case 3:* Demand in the spot market increases sharply during 5.00 PM - 9.00 PM

Figure 4-6 shows the nominal load curve of the system and shows how the load curve is modified after the Base-ILM case is simulated. It is seen that the peak load occurs during 11.00 AM -1.00 PM and 6.00 PM - 8.00 PM. The Base-ILM scheme works particularly during the evening peak and helps flatten the peak to a certain extent. The total load that is called for interruption during 7.00 PM is about 6.4% of the total demand.

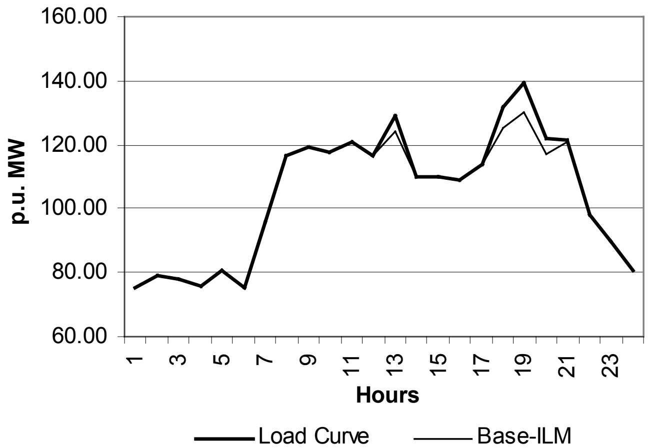

Figure 4-6: System load curve: Case 1

In Case 2, with loss of one large generator, more interruption (13.6% of the total peak demand) is required by the ISO to maintain the system conditions (Figure 4-7).

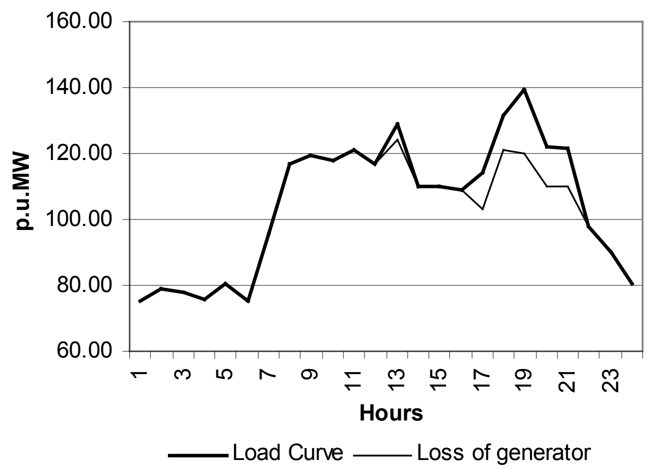

Figure 4-7: System load curve: Case 2.

When the demand in the spot market increases sharply, the interruptible load customers help to reduce the system demand (Figure 4-8). However, the ISO will have to pay a very high price since the interruptible load offer prices tend to be high in this case.

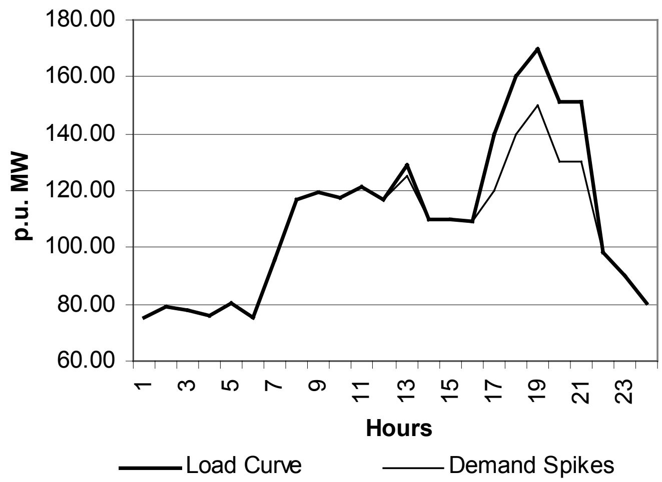

Figure 4-8: System load curve: Case 3

Figure 4-9 shows the total load interruption and the system operating reserves. The demand interruption trend line shows that the total interruption is inversely related to the system operating reserve.

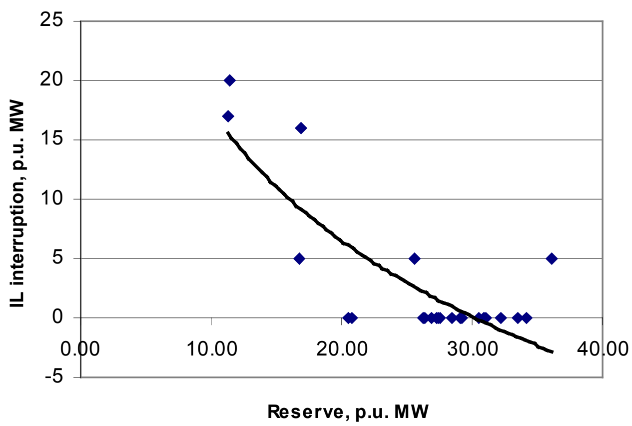

Figure 4-9: System operating reserve versus total load interruption (in Case 2)

Figure 4-10 shows the ISO pay price during a day for different cases. In Cases 2 and 3, the system operating reserves are low, the ILM customers tend to bid high, the market clearing price is thus higher than that in the base case.

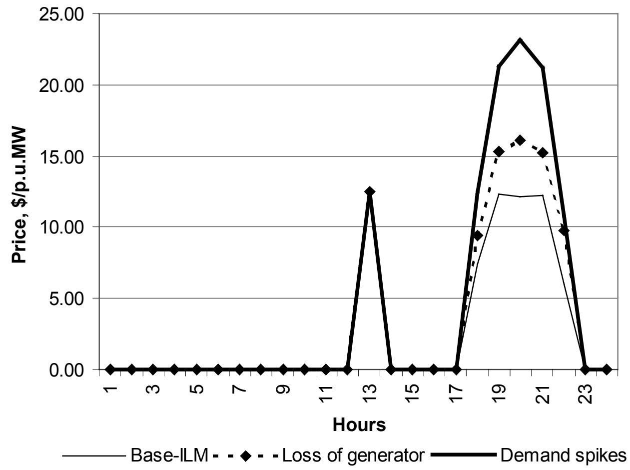

Figure 4-10: ISO pay-price

Table 4-1 shows the total demand interruption and total payment by the ISO during a day for different cases. For the most severe contingency case (Case 3), the ISO has to pay the most to compensate for the shortfall in the available generation.

Table 4-1: Total demand interruption and payment by the ISO

Cases	Payment (US$)	Total interruption (MWh)
Case 1 (Base-ILM)	28,925	3,208
Case 2 (Base-ILM + Loss of Generator)	82,181	6,906
Case 3 (Base-ILM + Demand Spikes)	165,648	10,603

4.5 Concluding Remarks

In this chapter, the design of a market for interruptible load management within the secondary reserve ancillary service has been proposed and has proved to function well. The locational aspect of interruptible load offers have been incorporated in the market framework through marginal loss coefficients at every load bus. The chapter also attempts to incorporate the behavior of interruptible load offers with respect to the information on system operating reserve forecast. The simulation results of case studies have shown that the interruptible load market would help to reduce the system demand during the peak hours and in cases of contingencies. With proper contracting framework, interruptible load market should be a good option as ancillary service for the ISO to choose among its available services.

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CHAPTER 5

INTERRUPTIBLE LOAD SERVICES FOR TRANSMISSION CONGESTION MANAGEMENT

This chapter addresses the issue of procurement of interruptible load services by the independent system operation (ISO) for transmission congestion management. The proposed Congestion Relief Model is based on an optimal power flow framework which can be used for the real-time selection of interruptible load offers while satisfying the congestion management objective. The model can specifically identify buses where corrective measures need to be taken for relieving congestion over a particular congested line. It is shown that the scheme is very effective in handling system congestion. The interruptible load market proves to work efficiently. The CIGRE 32-Bus system is used for the case study.

5.1 Congestion Management Methods: A Brief Overview

In a deregulated electricity market, the task of the ISO is to ensure that contracted power transactions are carried out reliably. However, due to a large number of transactions taking place simultaneously, transmission networks may easily get congested. There have been a number of methods, both technical and economic, dealing with congestion management in deregulated electricity markets. The technical methods are generally based on optimal generation re-dispatch with security and transmission constraints, operation of transformer taps, outages of the congested lines, load curtailments, and operation of FACTS devices. The economic instruments generally include methods of market splitting, counter trade, *etc.*

Three very different methods of accomplishing the same task - operation of the transmission system in the deregulated power systems - were discussed in detail in [1]:

- The optimal power flow (OPF) based method implemented in the United Kingdom, parts of the United States, Australia and New Zealand.
- The point of connection tariff and price area congestion model used in Sweden and Norway, respectively.
- Transaction based model used in the United States.

It was concluded in [1] that above three methods are pragmatic solutions implemented in advance of complete theoretical understanding. Each method succeeds in maintaining power system security but differ in their impacts on the economics of energy market. In [2], a minimum-distance generation re-dispatch was proposed, which disregarded the economic value of the transaction adjustment. In [3], price (marginal cost) signals were used for the generators to manage congestion and the solutions under rational behavior assumption are identical to the solution of a OPF. A similar approach was suggested for the pool model in [4], where the cost of congestion was bundled with the marginal cost at each bus. A bilateral model was also investigated in [4], and a congestion cost minimization approach was proposed. However, since this congestion cost is determined by the transmission owner, it might have some negative incentives for lowering the transmission limits.

The design of an optimal interruptible load contract has been attempted in [5] by using the mechanism design. It was shown that the so designed contract would give the customers enough incentive to sign up voluntarily for the right contract and reveal their true value of power. The role of demand elasticity in congestion management and pricing in a competitive electricity market was investigated in [6]. The actions of price responsive loads could be represented in terms of the customers' willingness-to-pay. From each customer's demand curve, the elasticity of the load at different prices is known and the benefit function is derived. The load at each bus ceases to be a fixed quantity and becomes a decision variable in the ISO's optimization problem. In this way, the ISO has additional degrees of freedom in determining necessary actions for network congestion management.

An optimal power flow (OPF) based framework was proposed in [7] to determine the optimal incentive rates of an interruptible tariff mechanism. It was shown that the interruptible tariff mechanism would be able to aid system operation during peak load periods, such as increased reliability margins, improving voltage profiles as well as relieving network congestion.

In [8], the design of a market for interruptible loads within the secondary reserve ancillary service was proposed and proved to function well. The locational aspect of interruptible load offers was incorporated in the market operation through marginal loss coefficient at every load bus. The paper also attempted to incorporate the interruptible load bidding behavior with respect to the information on system operating reserve forecast.

The present chapter proposes an integrated technical-cum-market based framework for congestion management, which uses interruptible load services as a tool for the ISO to provide transmission congestion relief in the dispatch stage. This chapter develops a scheme for the ISO to identify those buses in the system that can effectively influence the power flow over a particular transmission line. These factors, termed as *congestion relief indices* (CRI), are determined for each bus and specifically denote the "relief ability" of a load with respect to a certain transmission line.

The task of the ISO now is to find the most effective set of loads to be curtailed, both in terms of transmission relief and financial compensation. The ISO operates an interruptible load service market in the dispatch stage, one-hour ahead of real-time. In this market, interruptible load participants offer their interruption load capability for the next hour and their associated price offer. Based on the obtained CRI and submitted offer information from interruptible load participants, a Congestion Relief Model (CRM) is executed every hour to obtain the optimal interruption schedule for transmission congestion relief.

5.2 Transmission Congestion Relief Index (CRI): Mathematical Formulation

As discussed in the previous section, a set of parameters that determine the sensitivity of power flow on a line to load reduction at a bus is developed and presented in this section. These are termed as "Congestion Relief Index".

Let us consider the basic power flow equations:

$$\Delta P_i = P_{g_i} - P_{d_i} = \sum_{j,\, j \neq slack} |V_i||V_j| Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \tag{1}$$

$$\Delta Q_i = Q_{g_i} - Q_{d_i} = -\sum_{j,\, j \neq \mathrm{slack}} |V_i||V_j| Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \tag{2}$$

ΔP_i and ΔQ_i denote the injections of active and reactive power respectively at bus *i*.

The power flow on line *i-j*, connecting bus *i* and bus *j*, can be calculated using:

$$P_{ij} = V_i \cos\delta_i \{\mathrm{Re}(I_{ij})\} + V_i \sin\delta_i \{\mathrm{Im}(I_{ij})\} \tag{3}$$

$$Q_{ij} = V_i \sin\delta_i \{\mathrm{Re}(I_{ij})\} - V_i \cos\delta_i \{\mathrm{Im}(I_{ij})\} \tag{4}$$

where, $\mathrm{Re}(I_{ij})$ and $\mathrm{Im}(I_{ij})$ are the real and imaginary parts, respectively, of the line current on the transmission line *i-j*, corresponding to the power flow P_{ij}. These are given below:

$$\mathrm{Re}(I_{ij}) = V_i Y_{ij}\cos(\theta_{ij} + \delta_j) - V_i Y_{ij}\cos(\theta_{ij} + \delta_i) + V_i Y_{chij}\sin\delta_i \tag{5}$$

$$\mathrm{Im}(I_{ij}) = V_j Y_{ij}\sin(\theta_{ij} + \delta_j) - V_i Y_{ij}\sin(\theta_{ij} + \delta_i) + V_i Y_{chij}\cos\delta_i \tag{6}$$

Replacing (5) and (6) in (4) we have:

$$P_{ij} = V_i V_j Y_{ij}\cos(\theta_{ij} + \delta_j - \delta_i) - V_i^2 Y_{ij}\cos\theta_{ij} + V_i^2 Y_{ch_{ij}}\sin 2\delta_i \tag{7}$$

$$Q_{ij} = -V_i V_j Y_{ij}\sin(\theta_{ij} + \delta_j - \delta_i) + V_i^2 Y_{ij}\sin\theta_{ij} - V_i^2 Y_{ch_{ij}}\cos 2\delta_i \tag{8}$$

Applying Taylor series approximation to (7) and (8), respectively, we can write:

$$\Delta P_{ij} = \frac{\partial P_{ij}}{\partial \delta_i}\Delta\delta_i + \frac{\partial P_{ij}}{\partial \delta_j}\Delta\delta_j + \frac{\partial P_{ij}}{\partial |V_i|}\Delta V + \frac{\partial P_{ij}}{\partial |V_j|}\Delta V_j \tag{9}$$

$$\Delta Q_{ij} = \frac{\partial Q_{ij}}{\partial \delta_i}\Delta\delta_i + \frac{\partial Q_{ij}}{\partial \delta_j}\Delta\delta_j + \frac{\partial Q_{ij}}{\partial |V_i|}\Delta V + \frac{\partial Q_{ij}}{\partial |V_j|}\Delta V_j \tag{10}$$

Equation (9) and (10) can be re-written in terms of a set of coefficients as follows:

$$\Delta P_{ij} = a_{ij}\Delta\delta_i + b_{ij}\Delta\delta_j + c_{ij}\Delta V_i + d_{ij}\Delta V_j \tag{11}$$

$$\Delta Q_{ij} = a'_{ij}\Delta\delta_i + b'_{ij}\Delta\delta_j + c'_{ij}\Delta V_i + d'_{ij}\Delta V_j \tag{12}$$

The coefficients appearing in (11) and (12) can be obtained using partial derivatives of the real and reactive power flow relationships given in (7) and (8) respectively, with respect to the variables δ and *V*. These coefficients are given below:

$$a_{ij} = V_i V_j Y_{ij}\sin(\theta_{ij} + \delta_j - \delta_i) + 2V_i^2 Y_{ch_{ij}}\cos 2\delta_i \tag{13}$$

$$b_{ij} = -V_i V_j Y_{ij}\sin(\theta_{ij} + \delta_j - \delta_i) \tag{14}$$

$$c_{ij} = V_j Y_{ij}\cos(\theta_{ij} + \delta_j - \delta_i) - 2V_i Y_{ij}\cos\delta_{ij} + 2V_i Y_{chij}\sin 2\delta_i \tag{15}$$

$$d_{ij} = V_i Y_{ij}\cos(\theta_{ij} + \delta_j - \delta_i) \tag{16}$$

$$a'_{ij} = V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) + 2V_i^2 Y_{ch_{ij}} \sin 2\delta_i \tag{17}$$

$$b'_{ij} = -V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{18}$$

$$c'_{ij} = -V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) + 2V_i Y_{ij} \sin \delta_{ij} - 2V_i Y_{chij} \cos 2\delta_i \tag{19}$$

$$d'_{ij} = -V_i Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{20}$$

Again, let us consider the basic power flow equations (1) and (2) and apply Taylor's Series expansion. We get the well known matrix-vector relationship in terms of the Jacobian matrix J as given below:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = [\mathrm{J}] \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} = \begin{bmatrix} J_{11} & J_{12} \\ J_{21} & J_{22} \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} \tag{21}$$

J_{11}, J_{12}, J_{21}, J_{22} are appropriate sub-matrices of the Jacobian matrix J derived from the Taylor Series approximations.

Neglecting the coupling between ΔP and $\Delta|V|$ and between ΔQ and Δδ we can simplify (21) as follows:

$$[\Delta P] = [J_{11}][\Delta\delta] \tag{22}$$

and

$$[\Delta Q] = [J_{22}][\Delta|V|] \tag{23}$$

In this problem discussed, we will neglect the reactive power flows in the system in order to keep the computational burden low, and in order to explain the proposed method as well as to demonstrate the case study better. Reactive power flow equations can, however, be easily incorporated in this method without any difficulty.

Then we can write from (22):

$$[\Delta\delta] = [J_{11}]^{-1} [\Delta P] = [M][\Delta P] \tag{24}$$

where, [M] is the inverse of matrix [J_{11}].
or,

$$\Delta\delta_i = \sum_{j=1}^{n} m_{ij}\Delta P_j \tag{25}$$

Since we have neglected the couplings ΔP - $\Delta|V|$ and ΔQ - $\Delta\delta$, and also the reactive power flow, we can simplify (9) and hence (11), while neglecting (10) and (12), to get:

$$\Delta P_{ij} = a_{ij}\Delta\delta_i + b_{ij}\Delta\delta_j \tag{26}$$

Using (25) and (26) we can write:

$$\Delta P_{ij} = a_{ij}\sum_{l=1}^{n} m_{il}\Delta P_l + b_{ij}\sum_{k=1}^{n} m_{jk}\Delta P_k \tag{27}$$

$$\Delta P_{ij} = \left(a_{ij}m_{i1} + b_{ij}m_{j1}\right)\Delta P_1 + \left(a_{ij}m_{i2} + b_{ij}m_{j2}\right)\Delta P_2 + \ldots + \left(a_{ij}m_{i_n} + b_{ij}m_{j_n}\right)\Delta P_n \tag{28}$$

Defining $CRI_{ijk} = a_{ij}m_{ik} + b_{ij}m_{jk}$ we can have the following important equation:

$$\Delta P_{ij} = CRI_{ij1}\Delta P_1 + CRI_{ij2}\Delta P_2 + \ldots + CRI_{ijk}\Delta P_k + \ldots + CRI_{ijn}\Delta P_n \tag{29}$$

Equation (29) denotes that the change in the power flow on a transmission line from a bus *i* to bus *j* is affected by the change in the power injection at a bus. CRI_{ijk} denotes how much the active power flow over a transmission line *i-j* would change with a unit change in active power injection at bus *k*. High value of CRI_{ijk} indicates that the change in power injection at a bus *k* will have high influence on the power flow on line *i-j*.

Now, if ΔP_{ij} is the overload power (*i.e.,* the amount above the line transfer capability limit) on line *i-j*, the job of the ISO is to remove this violation of power flow limit. The ISO would consider choosing to change active power injections at those buses whose *CRI* values are substantially high in order to manage the congestion. Since we assume that the power generation at a bus is not changing, thus, change in active power injection is nothing but the change in active power demand at this bus. Thereby, we now refer the change in the real power injection at a bus as real power demand reduction or interruption at that bus.

It is noted that the treatment presented above draws on the same approach as discussed in [9] and the CRI is similar to the power transfer distribution factor (PTDF) as described in [10].

5.3 Optimal Contracting of Interruptible Load

From (29) in Section 5-2, we have an explicit relation governing the change in power flow on a line *i-j* and change in real power injection at each bus *i*, using *CRI*.

With this information available *a priori* with the ISO, since it can be easily determined from a base case load flow run every hour, the task of the ISO is to manage an interruptible load market for transmission congestion relief. The various objectives of the ISO can be summarized as follows:

- Total line power flow violations from contracted transactions is minimized;
- Total ancillary service cost (which is the total payment to the selected interruptible load offers) is minimized;
- Mandatory requirements on maintaining a minimum level of operating reserve is satisfied;
- All system operating constraints are within their limits.

For the sake of continuity, we assume the same characteristics of interruptible load participants with regard to their offer price trends as that in Chapter 4 (see Figures 4-3 and 4-4) in response to system operating reserve forecast information.

The optimal interruptible load contracts will be based on selected offers, specifying the interruption called for, from each customer type at each hour in real-time. Each selected offer will be paid the uniform price, which is the highest accepted offer price. The market structure proposed here is similar to the one proposed in Chapter 4 (see Figure 4-1) and works on an hour-ahead basis.

Figure 5-1 shows the working scheme of the proposed optimal constructing scheme for interruptible loads to aid in congestion relief, in which the ISO has to execute two consecutive models for every hour in a day:

- The basic load flow model (LFM) is to be executed every hour to determine the lines which are congested and *CRI* at every load bus. *CRI* will be used in the congestion relief model;
- The congestion relief model (CRM), which is a modified OPF model, includes the interruptible load offers characteristics as discussed in Section 4.2.1. The

objective is minimization of a *compromise objective*, including total line violations and ancillary service payment by the ISO to the selected interruptible load offers. The *CRIs* calculated from LFM are used in the objective function of CRM. CRM determines the uniform price to be paid to all interruptible load offers by the ISO and the total amount of load to be interrupted for each selected offer in the next hour.

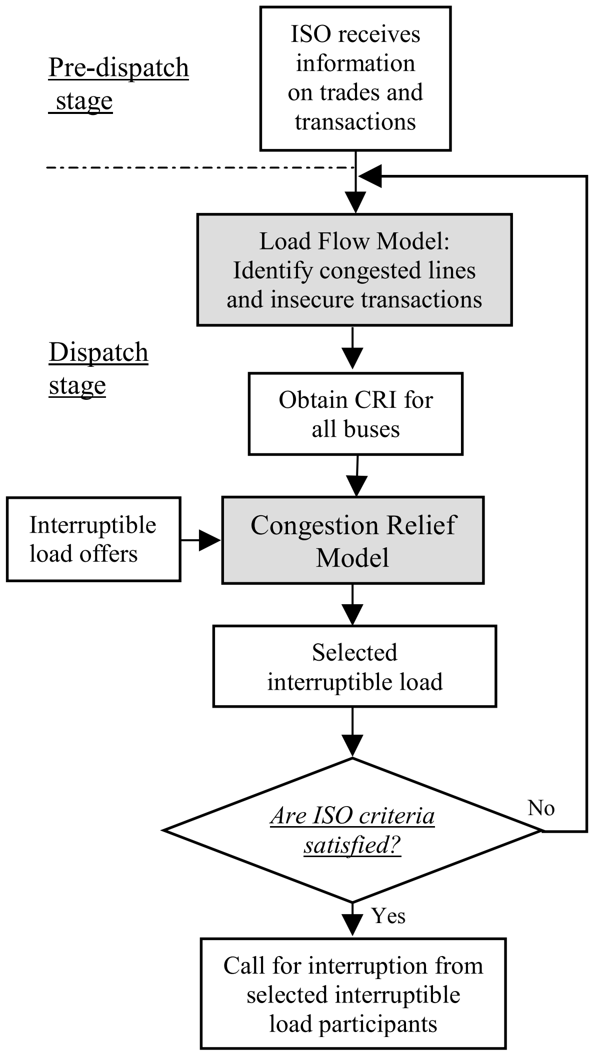

Figure 5-1: Schematic diagram of the proposed transmission congestion management framework

5.3.1 The Load-Flow Model

The basic load flow equations, modified to include the power generation and demand separated according to those through bilateral contract and those traded in the spot market, is as follows:

$$\Delta P_i^{(LFM)} = PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} = \sum_{j,\, j\neq slack} |V_i||V_j||Y_{ij}| \cos(\theta_{ij} + \delta_j - \delta_i) \quad (30)$$

$$QG_i - QD_i + QC_i = -\sum_{j,\, j\neq \text{slack}} |V_i||V_j||Y_{ij}| \sin(\theta_{ij} + \delta_j - \delta_i) \quad (31)$$

The left-hand side of the equation (30) denotes the active power injection at bus *i*. From the LFM, those lines which are overloaded will be identified. The simulation of bilateral contracts for generation and demand is presented in detail in Appendix 1.

5.3.2 The Congestion Relief Model

Objective Function:

From equation (29) and our earlier discussion, ΔP_{ij} depends on the change in power injection at a bus, which is virtually the load interruption at a bus ΔP_k. The objective of the ISO is to minimize the amount of congestion over the transmission system by selecting to interrupt appropriate load buses. The *CRIs* identified in load flow model is used in the congestion management objective, which is to minimize total line flow violations:

$$VIOL = \sum_{i,j} \Delta P_{ij} = \sum_{i,j} \sum_{k} CRI_{ijk}.\Delta P_k \quad (32)$$

The objective of the ISO is also to minimize the service cost for each hour paid to interruptible load customers selected for their demand interruptions. This is because if the objective function is only for reducing the congestion, the ISO would end up with paying a very high price for the interruption cost. The payment objective is:

$$Payment = \sum_{i} (\rho.\Delta PD_i) \quad (33)$$

Note that ρ is the uniform interruptible load pay-price that is determined by CRM and is payable to all interruptible load offers invoked by the ISO.

A compromise objective function is then formulated, combining the above two objectives as defined by (32) and (33), to satisfy the overall objective of the ISO, which is to minimize total line flow violations as well as total payment paid to the interruptible load offers.

$$OBJ = \sqrt{\left(\frac{VIOL}{VIOL^*}\right)^2 + \left(\frac{Payment}{Payment^*}\right)^2} \tag{34}$$

$VIOL^*$ and $Payment^*$ are the minimum values of violations and payment, respectively, when these objective functions are individually minimized. These are already known before the compromise optimization program is solved.

Load Flow Equations:

$$\Delta P_i^{(CRM)} = \sum_{j,\, j\neq slack} |V_i||V_j|Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \tag{35}$$

$$QG_i - QD_i + QC_i = -\sum_{j,\, j\neq \text{slack}} |V_i||V_j|Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \tag{36}$$

The left-hand side of Equation (35) denotes the active power injection at a bus i. The change in power injection in CRM and LFM is the power interruption at a bus. Thus:

$$\Delta PD_i = \Delta P_i^{(CRM)} - \Delta P_i^{(LFM)} \tag{37}$$

Upper and Lower Limits on Buses Voltages:

$$|V_i| = \text{constant}, \quad \forall i = 1,\ldots, NG \tag{38}$$

$$V_i^{\min} \le |V_i| \le V_i^{\max}, \quad \forall i = 1,\ldots, NL \tag{39}$$

Upper and Lower Limits on Reactive Power Support:

$$QC_i^{\min} \le |QC_i| \le QC_i^{\max}, \quad \forall i = 1,\ldots, NL \tag{40}$$

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory minimum level of operating reserve is maintained at all time.

$$\sum_{i}^{NG} PG_i^{\max}.UC_i \; - \sum_{i}^{NL} PD_i \; + \sum_{i}^{ILM} \Delta PD_i \; \leq R \tag{41}$$

Limit on Interruption: Each interruptible load offer is represented in the model by a binary integer variable. The total interruption invoked by the ISO from is limited by the offered quantity:

$$\Delta PD_i \; \leq \mu_i \, .U_i \, , \qquad \forall i = 1,..., NILM \tag{42}$$

The quantity offered by an interruptible load market participant is limited by the total demand at its disposal.

$$\mu_i \; \leq a_0 .PD_i \, , \qquad \forall i = 1,..., NILM \tag{43}$$

where, a_0 is a scalar, $0 < a_0 < 1$, which determines how much of the demand that could be made available for curtailment by the interruption load market participant, without causing any economic loss to itself.

Market Settlement: It is proposed that the interruptible load market settlement is a non-discriminating auction where all selected offers will be paid the same price (ISO pay-price) which is the highest accepted offer-price. The ISO pay-price can be included in the model as:

$$\rho \;\; \geq U_i \, .\beta_i \, , \qquad \forall i = 1,..., NILM \tag{44}$$

The CRM as described above, is a mixed integer nonlinear programming problem and is solved using the GAMS/DICOPT solver [11].

5.4 Simulation Studies and Discussions

5.4.1 System Descriptions

The CIGRE-32 bus system, which approximately represents the Swedish network, is used for the simulation studies [12]. Details of the system are provided in Appendix 2.

5.4.2 Results and Discussions

The models described in Section 5.3 and the system described in Section 5.4.1 are used to carry out a case study to examine the operation of the interruptible load market and its role in removing the congestion in the system. The model can be used for 24 hours in a day, however, in the present chapter, the results for only one single hour are reported. Table 5-1 shows the total demand interruption and the total payments by the ISO during peak load hour (19:00 hour).

Table 5-1: Load interruption and congestion management cost

	at 19:00 hour
Total load interruption (MWh)	177.7
Payment (US$)	4,442.5

Table 5-2 shows the lines which are identified as congested lines in the load flow model. Those line violations are largely influenced by load interruption at the buses whose congestion relief indices are substantially high as compared to those of other buses. For example, the line 4072-4071 has 37.5 MW overloaded, as identified by the model, the two buses 4072 and 2032 has significant high value of *CRI*, which means that interrupting the load at those buses will most likely reduce the congestion. The ISO would be able to remove those line violations by selecting the interruptible load offers in the interruptible load market. Those interruption are from buses 4072, 2032, *etc.,* as tabulated in Table 5-2.

Table 5-2: Line violations and demand interruptions

Line	Line flow Violation (MW)	Buses with significant *CRI*	ΔP (MW)
4072-4071	37.5	*4072* *2032*	19.5 12.6
4071-4012	62.4	*4021* *1022* *1011*	35.2 48.4 12.4
4012-4022	22.3	*4031* *1012*	10.2 13.4
4031-4041	0.4	*1044* *1045*	0.4 0.0
4022-4031	18.2	*4062* *1013*	6.8 18.8

5.5 Concluding Remarks

The proposed congestion management method could specifically identify the locations where corrective measures need to be taken for relieving congestion. A market for interruptible load has been designed and integrated with the Congestion Relief Model. The simulation results of case studies have shown that the scheme would be very effective in handling transmission system congestion. The interruptible load market works efficiently and is particularly effective when the system operating reserve is low. With a proper contracting framework, interruptible load market should be a good tool for congestion management of the ISO.

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CHAPTER 6

INVESTMENT IN RESERVE SERVICES FOR CONGESTION MANAGEMENT: A COST-BENEFIT ANALYSIS

This chapter develops a framework for the evaluation of the long-term congestion management solution by the "fast-startup" gas-turbine generators based on the traditional cost-benefit analysis. This involves a planning exercise to determine the location and size of gas-turbine generators at different buses in the network such that the total cost of investment in gas-turbine generators and the cost of system congestion is minimized. A bus-wise cost-benefit analysis is carried out by solving iteratively a dc optimal power flow model. The CIGRE 32-Bus system is used for the case study. It is shown that the long-term decisions on investment in gas-turbines would be very much dependent on the opportunity cost of gas-turbine generators with respect to the system transmission capacity available and the associated congestion problem.

6.1 Introduction

In Chapter 5, we have proposed the development of an interruptible load service market to address the problem of managing transmission congestion in deregulated power systems. Using a base flow run, the "congestion relief indices" can be obtained for each power transactions taking place in the system.

We have also discussed in the last chapter about various methods - both technical and economic - that have been proposed by researchers to address the congestion management problem.

However we must note that power systems, where transmission bottlenecks exist continuously, would require a long-term solution to the problem. In such cases, it is more a problem of insufficient available transmission capacity than a mere congestion on a line, that can be handled by a price area separation or generation re-scheduling.

In fact, methods such as pricing or generation re-scheduling or even interruptible load invocation strategies, if used for addressing transmission capacity shortages and thereby arising congestion problems, could introduce other inefficiencies in the system.

The problem associated with the above mentioned methods is that they may introduce the risk of increasing electricity prices due to the market power of local generators in the congested areas.

An alternative to the above mentioned schemes for addressing transmission capacity shortage and associated congestion is through the installation of "reserve" gas-turbine generators which can be brought online to the system within a short time. The installation of gas turbine generators at different buses will provide relief to the system in terms of transmission line overloads in case of contingencies. It would help the ISO to manage the congestion while stabilizing the market in the congested areas.

The present paper proposes a scheme for the evaluation of long-term investments by the ISO on gas-turbine generators. The objective of the ISO is to determine the optimal location and size of the gas-turbine generators which can effectively help reduce the congestion problem in the system operations at minimum cost and in the long-run provide a solution to transmission bottlenecks.

The cost defined here involves the cost of installing the gas-turbine generators and the *"opportunity cost"* of not installing the gas-turbine generators (OCG) with respect to the transmission congestion in the system. This OCG denotes how much costs the system would incur due to transmission congestion if the generator is not installed and operated. The selection of locations and sizes to the gas-turbine generators depends largely on this "opportunity cost". Sensitivity analysis has been carried out to capture those dependencies. A simple algorithm has been proposed to carry out a bus-wise cost-benefit analysis to ensure that the gas-turbine generators would be cost-effective in terms of transmission congestion relief in the long-run.

6.2 The Proposed Investment Plan Decision Making Framework

6.2.1 DC-OPF Model

The basic system analysis is carried out using a modified dc-OPF model to determine the investment decision on gas-turbine generators. A dc-OPF is considered here in order to reduce the computational burden significantly without affecting this basic principle of the decision making framework or without any loss of generality. The objective is minimization of total line violation cost plus the investment cost of gas-turbine generators (in terms of hourly investment cost plus operating cost).

Objective Function: The objective of the ISO is to minimize the total cost of installing and operating the gas-turbine generators and the cost associated with congestion. The later component (VC) is basically the "opportunity cost" of not-installing the gas-turbine generator and is termed as congestion cost. It simply implies how much it costs to the system per MW overload without the presence of a gas turbine generator.

$$OBJ = \sum_i GTC_i . GT_i + \sum_i \sum_j PVIOL_{ij} * VC \qquad (1)$$

GTC_i is the hourly cost of installing a gas-turbine generator at bus i, and $PVIOL_{ij}$ is the amount of line flow exceeding the thermal limit of the line i-j:

$$PVIOL_{ij} = P_{ij} - P_{ij}^{\max} \quad \forall P_{ij} > P_{ij}^{\max} \qquad (2)$$

Load Flow Equations: We have the basic dc power flow equations for bus i:

$$P_{g_i} - P_{d_i} = \sum_j B_{ij} . \delta_j \qquad (3)$$

To include the power generation and demand of bilateral contracts and power traded in the spot market, (3) can be rewritten as:

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} + GT_i = \sum_j B_{ij} . \delta_j \qquad (4)$$

The power flow one the line i-j between the bus i and bus j can be calculated as:

$$P_{ij} = -(\delta_i - \delta_j) . B_{ij} \qquad (5)$$

Simulation of Bilateral Contracts: Appendix 1 provides details on how the bilateral contracts are constructed and included in the simulation model.

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory minimum level of operating reserve is maintained at all time.

$$\sum_i^{NG} PG_i^{\max} . UC_i - \sum_i^{NL} PD_i + \sum_i GT_i \le R \qquad (6)$$

The dc-OPF model as described above, is a nonlinear programming problem and is solved using a well-known GAMS/MINOS solver [1].

6.3 Cost-Benefit Analysis

Though the optimal investment decisions on gas-turbine generators from the dc-OPF model is based on the cost minimization objective, it does not necessarily mean that the generator would be operating cost-effectively in the long-run. In order to analyze the cost-effectiveness of the selected generator, an explicit cost-benefit analysis is proposed here to determine which of the selected units are cost-effective and in what size. The outcome of the cost-benefit analysis is incorporated in the dc-OPF in an iterative way to arrive at the optimal solution. Figure 6-1 shows the flow chart describing the proposed method algorithm for optimal selection of gas-turbine generators following step- by-step procedure:

Step 1: Run dc-OPF model for 24 hours considering the hourly load demand at each bus. All buses are considered as possible "candidates" for gas-turbine generators' installations and constitute the initial *selection set*. The solution provides the preliminary selection of gas turbine generators at different buses in the system.

Step 2: With estimated sizes of the gas turbines generators, determine the standard size of the generator to be installed at each bus *i* and the total cost involved, considering a 15-year life.

Step 3: The marginal benefit from installing the gas turbine generator on the *i-th* bus is calculated by removing *i-th* bus's generator and re-running the dc-OPF while other things remain unchanged. The difference in the objective function is the marginal benefit from the generator installed on *i-th* bus.

Step 4: Calculate the benefit to cost ratio *(BCR)* for all selected generators. If *BCR* for the generator on bus *i* exceeds unity, then that generator is selected. If the *BCR* is less than unity, consider a generator of lower capacity and recalculate the *BCR* to check if it could yield a *BCR* greater than unity. Otherwise, the generator at this bus is rejected.

Step 5: Removing all rejected generators and corresponding buses from the *selection set* and go to Step 1. Go to Step 6 only when all buses have *BCRs* greater than unity.

Step 6: Run dc-OPF considering only the selected bus generators. If this gives a feasible solution, the selection is final.

Step 7: If Step 6 results in violation of any of the constraints, additional gas turbine generators will then be included in succession at buses, where they were previously rejected in Step 4, in decreasing order of their *BCRs* until a feasible solution is reached.

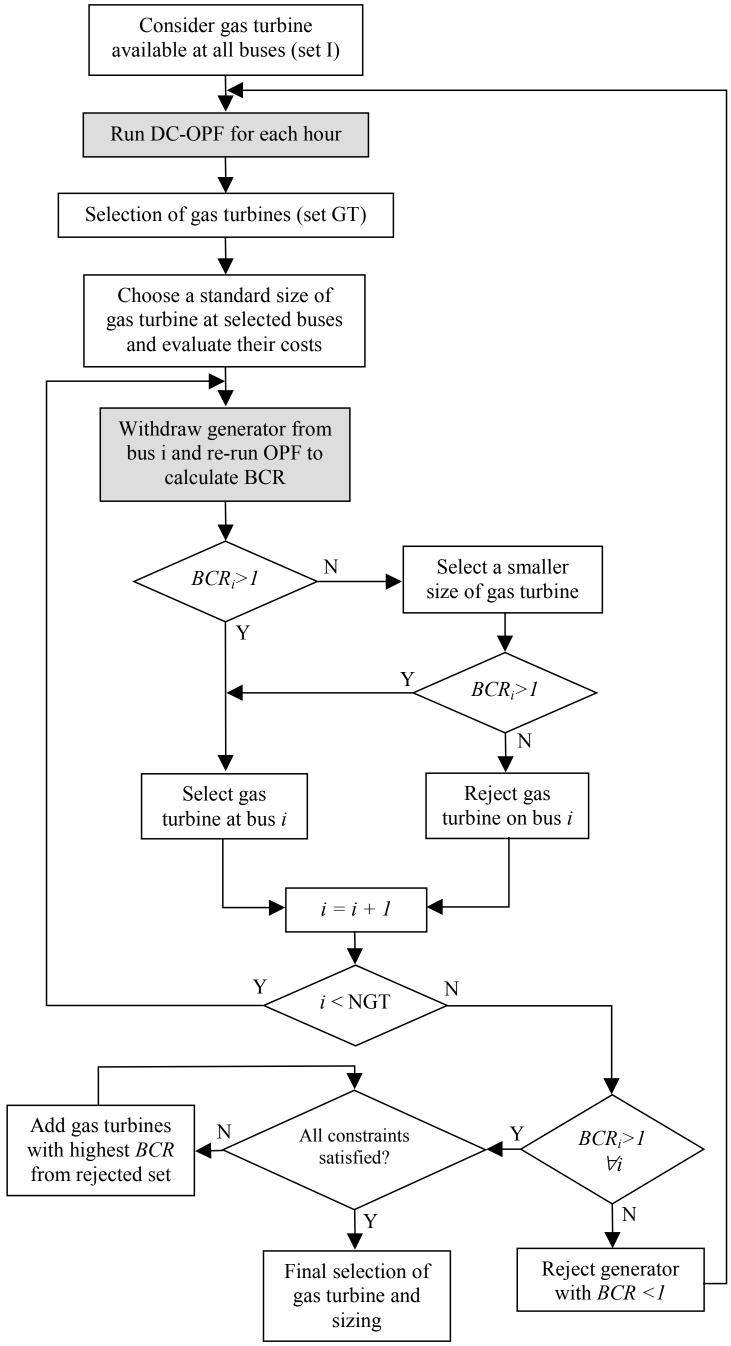

Figure 6-1: Scheme for optimal allocation and sizing of gas-turbine generators

6.4 Results and Discussions

6.4.1 Techno-economic analysis

The CIGRE-32 bus system, which approximately represents the Swedish network, is used for the simulation studies [2]. Details of the system are provided in Appendix 2.

The hourly load variation at a bus is accounted for by applying a load scaling factor (LSF) at each hour. The load at each hour *h* will be calculated by:

$$PD_i^h = PD_i.LSF^h \tag{7}$$

To begin with the ISO needs to work out a techno-economic analysis of gas-turbine generators using the unit's operating/name-plate ratings.

Table 6-1 provides the techno-economic data of a typical gas turbine generator to be considered as a "candidate" at different buses in the system [3].

Table 6-1: Techno-economic data of a typical gas-turbine generator

Data	Unit	
Size *(Cap)*	MW	100.00
Capacity cost *(CC)*	$/kW	395.00
Fuel type	Diesel oil	-
Net heat rate *(HR)*	Btu/kWh	11,785.00
Fixed O&M cost *(FOM)*	$/kW-yr	11.17
Variable O&M cost *(VOM)*	$/MWh	5.00
Economic life *(EL)*	years	15.00
Fuel cost *(FC)*	$/MBtu	6.00
Interest rate *(r)*	-	0.10

Table 6-2 presents the investment and operational cost analysis of the candidate gas turbine generator. The “candidate” gas turbines generators are considered to be available for investment at all buses with maximum capacity of 100 MW (1 p.u. MW). A capital cost of 400 $/kW installed capacity, variable operating cost of 5 $/kWh and fixed operating cost of 11.17 $/kW-year are considered for the study. Assuming also 15 years economic life of the gas turbine generator, the hourly cost of the generator would be 13.18 k$ per hour (per 100 MW). We have considered the opportunity cost "VC" to be $200 per MWh which is of the similar order as the unit cost of the gas-turbine generator ($131.8 per MWh).

Table 6-2: Economic costs of a gas-turbine generator

Cost component	Unit	Calculation Formula	Result
Plant capacity factor *(PCF)*	-		0.30
Operating hours *(OH)*	per year	= 8760**PCF*	2,628.00
Capital recovery factor[1] *CRF*(10%, 15 years)	-	-	0.13
Levelized factor *(LF)*[2] 6% price escalation	-	-	1.40
Annual fuel cost *(AFC)*	M$/year	= *Cap*OH*HR*FC*LF*	26.04
Annual fixed O&M Cost *(AFOM)*	M$/year	= *Cap*FOM*LF*	1.57
Variable O&M cost *(AVOM)*	M$/year	= *Cap*OH*VOM*LF*	1.84
Annual capacity cost *(ACC)*	M$/year	= *Cap*CC*CRF*	5.19
Total annual cost *(TAC)*	M$/year	= A*FC+AFOM+AVOM +ACC*	34.64
Hourly cost *(HC)*	$/hour	= *TAC/OH*	13,179.57
Unit cost *(UC)*	$/MWh	= *HC/Cap*	131.80

6.4.2 Location and Sizing of Gas Turbine Generators

The model described in Section 6.2 and the cost benefit analysis scheme described in Section 6.3 are used to carry out a case study to examine the role of gas turbine generator in providing congestion relief to the system in the long-run. In this case study, only one loading condition (during peak load hour at 19:00 o'clock) with LSF = 1.0 is considered.

Table 6-3 shows the selection of gas turbine generators at different buses in the network during 19:00 hour. As can be seen, after the first dc-OPF run (base case), six generators are selected by the model. However, only those at bus 4062 and 1041 have

[1] CRF is used to find the equivalent value of future annuity given the present investment equivalent: $CRF = \frac{r(r+1)^n}{(r+1)^n - 1}$ with r and n being the interest rate and number of years, respectively. More details can be found in [3].

[2] LF is used to calculate the uniform levelized annual equivalent of an inflation series:

$$LF = \frac{\left[1 - \left(\frac{1+a}{1+r}\right)^n\right]}{r-a} \cdot CRF$$ with a being the annual inflation rate.

BCRs greater than unity. As described in Section 6.3, in order to calculate the marginal benefit resulting from generators at bus *i*, the dc-OPF is re-run iteratively without a gas turbine generator at bus *i* selected in the previous dc-OPF run. However, in the subsequent OPF run, a new set of gas turbine generators is selected instead with different *BCR*. The dc-OPF has to be solved iteratively until the convergence at final solution when all selected gas turbines have *BCR* greater than unity (#4062, #1041, #1045, #4045).

Table 6-3: Selected gas turbine generators (GTGs) and its capacity

Iteration	Initial choice of *GTGs* at bus #	Buses with *BCR*>1	Buses rejected
1	4041	4062	4041
	4062	1041	4063
	4063		4051
	4051		1043
	1043		1042
	1042		4044
	4044		4061
	4061		
	1041		
2	4062	4062	4072
	4072	1041	4012
	4012	1045	4021
	1045		42
	4021		62
	42		
	62		
3	4062	**4062**	None
	1041	**1041**	
	1045	**1045**	
	4045	**4045**	

6.4.3 Evaluation of Network Support by Gas-Turbine Generators

An index to quantify total transmission system congestion, Congestion Index *(CI)*, is introduced, which will be used as an indicator of the contribution of the gas-turbine generator to providing congestion relief:

$$CI = \sqrt{0.5.\sum_{i,j}\left(P_{ij} - P_{ij}^{\max}\right)^2 / NT} \qquad \forall P_{ij} > P_{ij}^{\max} \tag{8}$$

Figure 6-2 shows the *CI* over a 24 hours time period in the system with and without the support of gas turbine generators. As can be seen, the installation of gas turbines has provided substantial support to improve network overloading condition, especially during the peak hour (19:00 hours).

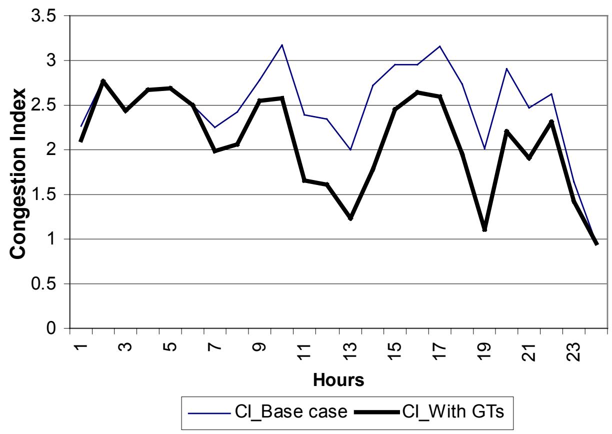

Figure 6-2: Congestion Index

In case of very high load (*LSF = 1.6*), the system experiences a condition of "energy not supplied". Without the installation of gas-turbine generators, the total energy not served during this hour is about 4000 MWh. As can be seen in Table 6-4, if the gas turbine generators are readily installed, it would otherwise reduce the total energy not served by almost 10%.

Table 6-4: Energy-not-served (MWh)

Bus #	*LSF*=1.6 without GTGs	*LSF*=1.6 with GTGs
4041	173.0	176.3
4063	346.5	274.5
4043	671.4	701.3
4045	784.8	505.1
4046	495.7	486.4
4061	408.3	408.3
1041	491.3	391.3
1044	242.6	259.8
62	8.2	0.0
51	456.8	475.3
Total	4078.6	3678.3

6.5 Concluding Remarks

This chapter presents a method to evaluate long-term investment decisions on gas turbine generator allocation and sizing for the congestion management purpose. The chapter proposes that the ISO would be the responsible party to carry out the analysis and investment in order to have the available tool to support system operation. Network congestion is modeled and incorporated in the objective function of the model, not as a separate constraint. Therefore, the network congestion may not be removed completely in all cases. However, simulation results obtained in case studies have shown that the network overloading can be greatly reduced with support of the gas turbines at the selected buses. The choice of the value of cost associated with network congestion is found to have large influence on the selection and sizing of the gas turbine, hence the network overloading relief is provided.

References

[1] "GAMS Release 2.25", in A User's Guide, GAMS Development Corporation, 1998.

[2] K. Walve, “Nordic 32-A CIGRE Test System for Simulation of Transient Stability and Long Term Dynamics”, Svenska Kraftnät, Sweden 1993.

[3] H.G. Stoll, *Least-Cost Electric Utility Planning*, John Wiley & Son, 1989.

CHAPTER 7

CONCLUSIONS AND FUTURE WORK

7.1 Conclusions

Since the last decade, the electric power industry has been undergoing a vast reform which mainly involves transition from natural monopolies, with centralized planning, to market based structures that are subject to competition. On the one hand, it is generally claimed that deregulation would improve the efficiency of power supply as a whole and thereby benefit consumers. On the other hand, it can be noted that competition has imposed new challenges to the operation of the electric power system, in terms of reliability and security issues. The independent system operator has to keep the system "healthy" while facilitating the bilateral as well as spot market transactions by procuring various ancillary services, *i.e.,* the supply of emergency reserves, reactive power support, among others, from different players in the market.

This thesis attempts to study various issues related to interruptible load management program as a means to improve the security margin of the deregulated power system operations, especially in cases of contingencies and transmission congestion.

In this respect, the thesis has covered a wide range of literature survey as well as a summary of the practices and the operational roles of interruptible load management. From this survey background, it is concluded that interruptible load management has a potential for providing additional reserves with the net effect as good as supply-side generation sources at lower costs.

An important part of this thesis is devoted to the design a market model for interruptible load customers who are willing to reduce their demand as and when requested, in return of a financial incentive. The ISO is responsible for market operation. The interruptible load customers will submit their offers for reduction of demand to the ISO, who will make an optimal selection of the interruptible load offers so as to satisfy its operating objectives. Various issues related to the procurements of interruptible load such as advance notification, locational aspect of the load, load power factors, are explicitly considered.

It can be concluded that functioning of this interruptible load market would considerably help the ISO to maintain the system operating reserves by reducing the overall system demand during the peak load hours as well as in cases of emergency. It is, therefore, very important to note that a proper contracting framework to attract customer participation, especially the large industrial customers, would enable the interruptible load market to function well.

It is desirable to investigate the operational roles of the interruptible loads other than its utmost objective of offering peak load reduction. To this effect, the thesis has examined the possibility of the interruptible load market in providing transmission congestion relief. A model for procurement of interruptible load services by the ISO for transmission congestion management has been developed, in which the importance of *congestion relief index* attributed to each load bus has been realized. The model is based on an optimal power flow framework that could determine, in real-time, the selection of the interruptible load offers while satisfying the congestion management objective. The model is able to locationally identify load buses where corrective measures need to be taken for relieving congestion over a particular congested line. It can be concluded that this scheme is effective in handling system congestion.

In order to provide a comparison of the economic viability of interruptible load option over the generation-side option, a cost-benefit analysis of the long-term investment on fast start-up generators as part of the system operating reserve has been studied in the subsequent part of this thesis. This involves a planning exercise to determine the location and size of gas-turbine generators at different buses in the network such that the total cost of investment and the total cost of unserved energy is minimized.

7.2 Scope for Future Work

As mentioned earlier, it is very important to have the demand-side participation in the electricity market, *i.e.,* the spot market, to improve the economic efficiency of the existing electricity market and limit the exercise of market power of the generators, especially the large ones, in the market. This thesis has established an ancillary service market for interruptible load customers where there is only one single buyer, the independent system operator, of their services. It is envisaged in the next phase of the work:

- The participation of the customer in the spot market will be investigated, as to address the questions: i) what are the likely interactions between the demand-side and the rest of the players in the market; ii) what will be the bidding strategies and the interruption scheme, including the amount of load to be interrupted and the notification time, as well as the payment scheme.

- It is important to study in price-responsiveness of the demand-side, *i.e.,* the price elasticity of demand, as it will help the independent system operator to predict the likely demand level in case of rocketing electricity prices.
- It is also important to consider the recovery characteristics of customer load after the interruption, since, neglecting this may overestimate the benefit of interruptible load management program.
- It is important to study the market power of the generators in the electricity markets and find out the possible solutions to mitigate it, one of which would be through interruptible load participation in the electricity market. Thus, the future study in this direction would be important.

APPENDIXES

1 Modeling Bilateral Contracts

In bilateral contract dominated markets, the generating companies can enter into direct contracts with customers that can be days, weeks, or even months in advance. In order to appropriately simulate such kind of energy contracts/transactions, a system of linear-equations is used denoting the linkages between various parties involved. Bilateral contracts simulated must adhere to the two basic rules:

i) The sum of all contracts entered into, by a customer, equates the total demand of the said customer:

$$\sum_j PGcon_{i,j} = PD_{i,b}, \quad \forall i = 1,\ldots,NL; j = 1,\ldots,NG \tag{1}$$

Where: $PGcon_{i,j}$ is the contracted demand (MW) matrix of a load bus i to be provided by a generator j.

ii) The sum of all contracts entered into by one generator, equals the contracted generation of the said generator. Accordingly we have:

$$\sum_i PGcon_{i,j} = PG_{j,b} \quad \forall i = 1,\ldots, NL; j = 1,\ldots, NG \tag{2}$$

Note that in (1), although we show that $j=1, \ldots, NG$; in a practical system, not all generators may have a bilateral contract with a load at bus i. In such case, the appropriate elements of the *PGcon* matrix will be zero. The same applies to (2) where not all loads $i=1, \ldots, NL$; will actually have a bilateral contract with generator j. In such case, the appropriate *PGcon* matrix elements will be zero.

Further more, the amount of generation from a generator j scheduled for bilateral contracts is within a certain range from its maximum generating capacity:

$$P_j^{\max}.UC_j.a_0 \leq \sum_i PGcon_{i,j} \leq P_j^{\max}.UC_j.a_1, \quad \forall i = 1,\ldots,NL; j = 1,\ldots,NG \tag{3}$$

Note here that we, however, have not considered the maximum allowable amount of energy transaction between a load i and generator j, due to the unavailability of data.

2 CIGRE 32-Bus System

The Swedish 32-bus test system [1], as shown in Figure A-1, is used in the thesis for different case studies performed in Chapters 4, 5 and 6.

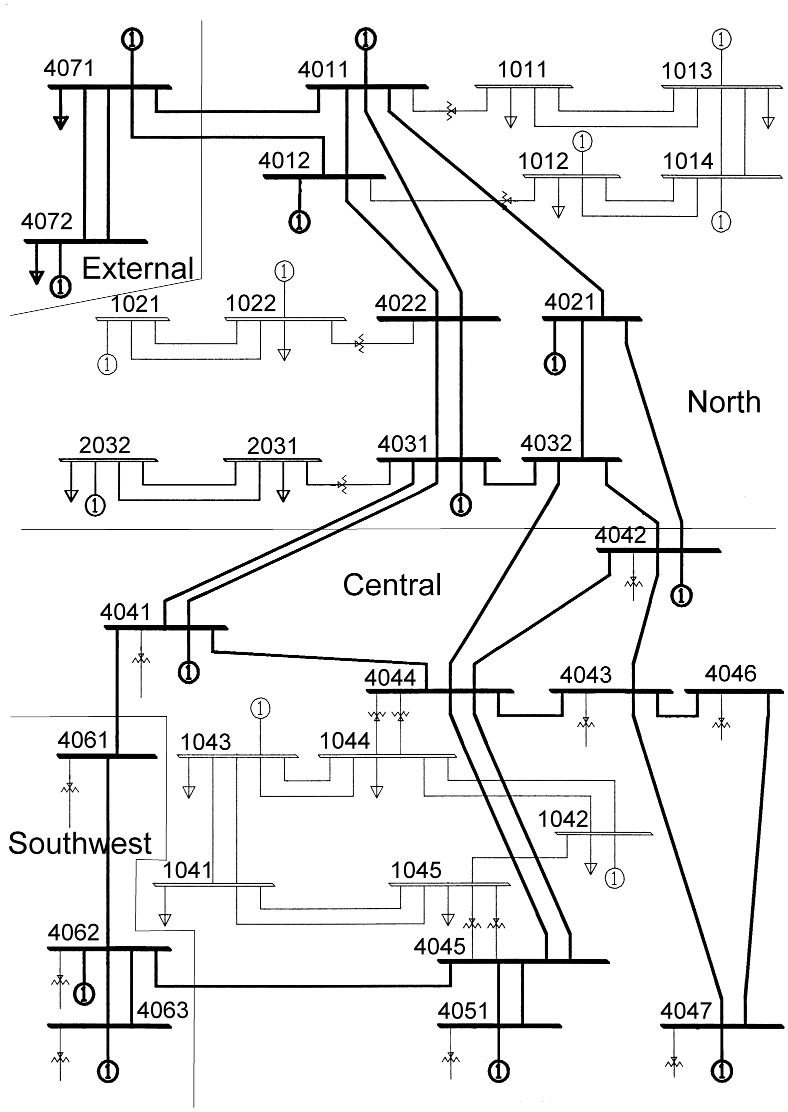

Figure A-1: CIGRE 32-Bus Test System Network Configuration

The system can be divided into 4 main areas:

- *North:* mostly consists of hydro power plants and some load centers.
- *Central*: consists of a large amount of load and large thermal power plants
- *Southwest*: consists of some thermal power plants and some load
- *External*: connects to the North, it has a mix of generation and load

There are 19 generator buses and 21 load buses in the system. The bus #4011 is considered as the slack bus. The main power transfer is from "north" to "central". The main transmission system is designed for 400 kV. There are also regional systems at the voltage levels of 220 kV and 130 kV. The generators and the loads in the system are simulated to participate in the bilateral contracts market as well as the spot market. The simulation of the bilateral contract market is presented in the following section. The detailed data of generator buses in the system is provided in Table A-1. The load data is presented in Table A-2.

Table A-1: Generators data

Bus #	P_{max} MW	Q_{max} MVAr	PD MW	QD MVAr	Q_{Sh} MVAr	Voltage level kV
4072	4500	1000	2000	500	-	400
4071	500	250	300	100	-400	400
4011	1000	500	-	-	-	400
4012	800	400	-	-	-100	400
4021	300	150	-	-	-	400
4031	350	175	-	-	-	400
4042	700	350	-	-	-	400
4041	300	300	-	-	200	400
4062	600	300	-	-	-	400
4063	1200	600	-	-	-	400
4051	700	350	-	-	100	400
4047	1200	600	-	-	-	400
2032	850	425	200	50	-	220
1013	600	300	100	40	-	130
1012	800	400	300	100	-	130
1014	700	350	0	0	-	130
1022	250	125	280	95	50	130
1021	600	300	0	0	-	130
1043	200	100	230	100	150	130
1042	400	200	300	80	-	130

Table A-2: Loads data

Bus #	PD MW	QD MVAr	QSh MVAr	Voltage level kV
4022	-	-	-	400
4032	-	-	-	400
4043	-	-	200	400
4044	-	-	-	400
4045	-	-	-	400
4046	-	-	100	400
4061	-	-	-	400
2031	100	30.00	-	220
1011	200	80.00	-	130
1041	600	200.00	200	130
1044	800	300.00	200	130
1045	700	250.00	200	130
42	400	125.67	-	130
41	540	128.80	-	130
62	300	80.02	-	130
63	590	256.19	-	130
51	800	253.22	-	130
47	100	45.19	-	130
43	900	238.83	-	130
46	700	193.72	-	130
61	500	112.31	-	130

In this thesis, we assumed that 60% of the available electricity generation from each generator can directly go into a bilateral contract with different loads, and that the rest 40% of the available electricity generation will be offered in the spot market. Likewise, 60% of the total demand at a bus is entered in bilateral contract with different generators, and the rest of the demand will be bought from the spot market.

References:

[1] K. Walve, “Nordic 32-A CIGRE Test System for Simulation of Transient Stability and Long Term Dynamics”, Svenska Kraftnät, Sweden 1993.