DEPARTMENT OF ELECTRICAL & ELECTRONICS ENGINEERING

Subject Name: **POWER SYSTEM RESTRUCTURING AND DEREGULATION**

Subject Code: **EE E89**

Prepared by

1. Mrs.S.Punitha , AP/EEE
2. Mr.V.Malarselvam, AP/EEE

Verified by: *Approved by:*

UNIT – I

FUNDAMENTALS AND ARCHITECTURE OF POWER MARKETS

Deregulation of Electric utilities: Introduction-Unbundling-Wheeling- Reform motivations-Fundamentals of Deregulated Markets – Types (Future, Day-ahead and Spot) – Participating in Markets (Consumer and Producer Perspective) – bilateral markets – pool markets. Independent System Operator (ISO)-components-types of ISO - role of ISO - Lessons and Operating Experiences of Deregulated Electricity Markets in various Countries (UK, Australia, Europe, US, Asia).

Eleven Mark Questions

1. Explain unbundling of utilities with a neat diagram.(Apr'10)

The power industry across the globe is experiencing a radical change in its business as well as in an operational model where, the vertically integrated utilities are being unbundled and opened up for competition with private players. This enables an end to the era of monopoly. Right from its inception, running the power system was supposed to be a task of esoteric quality. The electric power was then looked upon as a service. Control consisting of planning and operational tasks was administered by a single entity or utility. The vertical integration of all tasks gave rise to the term – vertically integrated utility. The arrangement of the earlier setup of the power sector was characterized by operation of a single utility generating, transmitting and distributing electrical energy in its area of operation. Thus, these utilities enjoyed monopoly in their area of operation. They were often termed as monopoly utilities.

Why were earlier utilities the 'monopolies'? The reason for monopoly can be traced right back to the early days when electricity was comparatively a new technology. The skeptical attitude of the government towards electricity led to investment by private players into the power sector, who in turn, demanded for the monopoly in their area of operation. This created a win-win situation for both- government and the electrical technology promoters. However, the government would not let the private players enjoy the monopoly and exploit the end consumer and hence introduced regulation in the business. Thus, the power industries of initial era became *regulated monopoly utilities.* The structure of a conventional vertically integrated utility is shown in Figure 1.1. As evident from the figure, there was only a single utility with whom the customer dealt with. Thus, only two entities existed in the power business: a monopolist utility and the customer.

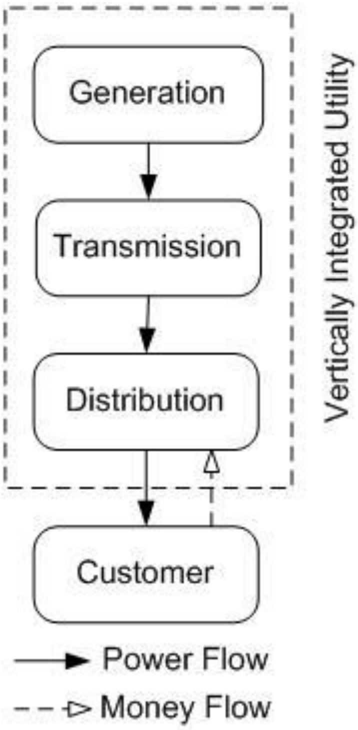


Fig 1.1

What does 'regulation' mean? The regulations are generally imposed by the government or the government authority. These essentially represent a set of rules or framework that the government has imposed so as to run the system smoothly and with discipline, without undue advantage to any particular entity at the cost of end consumer. All practical power systems of earlier days used to be regulated by the government. This was obviously so. The old era power industries were vertically integrated utilities and enjoyed monopoly in their area of operation. Whenever a monopoly is sensed in any sector, it is natural for the government to step in and set up a framework of way of doing business, in order to protect end consumer interests. Some of the characteristics of monopoly utility are:

1. Single utility in one area of operation enjoying monopoly.
2. Regulated Framework: The utility should work under the business framework setup by the government.
3. Universal Supply Obligation (USO): Utility should provide power to all those customers who demand for it.
4. Regulated Costs: The return on the utility's investments is regulated by the government.

In a nutshell, regulation is about checking the prices of the monopolist in the absence of private players and market forces.

2. Explain the structure of de regulated industry.

The next obvious question is, "what is deregulation or restructuring of an industry?" From the name, one can sense discontinuation of the framework provided by the regulation. In other words, deregulation is about removing control over the prices with introduction of market players in the sector. However, this is not correct in a strict sense. An overnight change in the power business framework with provision of entry to competing suppliers and subjecting prices to market interaction, would not work successfully. There are certain conditions that create a conducive environment for the competition to work. These conditions need to be satisfied while deregulating or restructuring a system. Sometimes, the word 'deregulation' may sound a misnomer. 'Deregulation' does not mean that the rules won't exist. The rules will still be there, however, a new framework would be created to operate the power industry. That is why the word 'deregulation' finds its substitutes like 're-regulation', 'reforms', 'restructuring', etc. The commonly used word in Europe is 'liberalization' of power industry; 'deregulation' is a more popular phrase in US.

If the power industries worked successfully with the regulated monopoly framework for over 100 years, what was the need for deregulating or changing the business framework of the system? There are many reasons that fuelled the concept of deregulation of the power industry. One major thought that prevailed during the early nineties raised questions about the performance of monopoly utilities. The takers of this thought advocated that monopoly status of the electric utilities did not provide any incentive for its efficient operation. In privately owned utilities, the costs incurred by the utility were directly imposed upon the consumers. In government linked public utilities, factors other than the economics, for example, treatment of all public utilities at par, overstaffing, etc. resulted in a sluggish performance of these utilities. The economists started promoting introduction of a competitive market for electrical energy as a means of benefit for the overall powerector. This argument was supported by the successful reform experiences of other sectors such as airlines, gas, telephone, etc.

Another impetus for deregulation of power industry was provided by the change in power generation technology. In the earlier days, cost-effective power generation was possible only with the help of mammoth thermal (coal/nuclear) plants. However, during the mid eighties, the gas turbines started generating cost effective power with smaller plant size. It was then possible to build the power plants near the load centers and also, an opportunity was created for private players to generate power and sell the same to the existing utility. This technology change, supposed to have provided acceleration to the concept of independent power producers, supported the concept of deregulation further. This technology change is supposed to have provided acceleration to the concept of independent power producers. This further supported concept of deregulation. This was specifically true where the financial losses were apparently high which was prevalent in some of the developing countries.

It should be noted that these are the indicative or major reasons for introducing the concept of deregulation in power industry. There are many other reasons as well. One of the important reasons is the condition under which power systems were regulated, did not exist anymore. There was no wind of skepticism about the electrical technology and all the initial investments in infrastructure were already paid back. Further, the deregulation aims at introducing competition at various levels of power industry. The competition is likely to bring down the cost of electricity. Then, the activities of the power industry would become customer centric.

The competitive environment offers a good range of benefits for the customers as well as the private entities. It is claimed that some of the significant benefits of power industry deregulation would include:

1. Electricity price will go down: It is a common understanding that the competitive prices are lesser than the monopolist prices. The producer will try to sell the power

at its marginal cost, in a perfectly competitive environment.

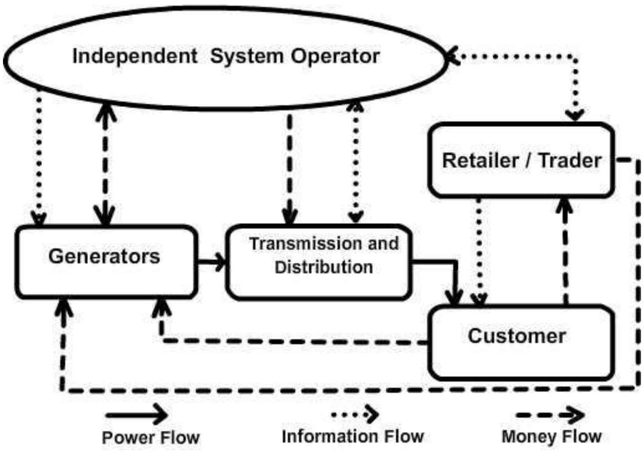
2. Choice for customers: The customer will have choice for its retailer. The retailers will compete not only on the price offered but also on the other facilities provided to the customers. These could include better plans, better reliability, better quality, etc.
3. Customer-centric service: The retailers would provide better service than what the monopolist would do.
4. Innovation: The regulatory process and lack of competition gave electric utilities no incentive to improve or to take risks on new ideas that might increase the customer value. Under deregulated environment, the electric utility will always try to innovate something for the betterment of service and in turn save costs and maximize the profit.

The deregulation of the industry has provided electrical energy with a new dimension where it is being considered as a commodity. The 'commodity' status given to electrical power has attracted entry of private players in the sector. The private players make the whole business challenging from the system operator's point of view, as it now starts dealing with many players which are not under it's direct control. This calls for introduction of fair and transparent set of rules for running the power business. The market design structure plays an important role in successful deregulation of power industry.

3. Describe various entities involved in power system restructuring.

The introduction of deregulation has introduced several new entities in the electricity market place and has simultaneously redefined the scope of activities of many of the existing players. Variations exist across market structures over how each entity is particularly defined and over what role it plays in the system. However, on a broad level, the following entities can be identified:

1. **Genco (Generating Company):** Genco is an owner-operator of one or more generators that runs them and bids the power into the competitive marketplace. Genco sells energy at its sites in the same manner that a coal mining company might sell coal in bulk at its mine.
2. **Transco (Transmission Company):** Transco moves power in bulk quantities from where it is produced to where it is consumed. The Transco owns and maintains the transmission facilities, and may perform many of the management and engineering functions required to ensure the smooth running of the system. In some deregulated industries, the Transco owns and maintains the transmission lines under the monopoly, but does not operate them. That is done by Independent System Operator (ISO). The Transco is paid for the use of its lines.



3. **Discom (Distribution Company):** It is the owner-operator of the local power delivery system, which delivers power to individual businesses and homeowners. In some places, the local distribution function is combined with retail function, i.e. to buy wholesale electricity either through the spot market or through direct contracts with Gencos and supply electricity to the end use customers. In many other cases, however, the Discom does not sell the power. It only owns and operates the local distribution system, and obtains its revenue by wheeling electric power through its network.
4. **Resco (Retail Energy Service Company):** It is the retailer of electric power. Many of these will be the retail departments of the former vertically integrated utilities. A Resco buys power from Gencos and sells it directly to the consumers. Resco does not own any electricity network physical assets.
5. **Market Operator:** Market operator provides a platform for the buyers and sellers to sell and buy the electricity. It runs a computer program that matches bids and offers of sellers and buyers. The market settlement process is the responsibility of the market operator. The market operator typically runs a day-ahead market. The near-real-time market, if any, is administered by the system operator.
6. **System Operator (SO):** The SO is an entity entrusted with the responsibility of ensuring the reliability and security of the entire system. It is an independent authority and does not participate in the electricity market trades. It usually does not own generating resources, except for some reserve capacity in certain cases. In order to maintain the system security and reliability, the SO procures various services such as supply of emergency reserves, or reactive power from other entities in the system. In some countries, SO also owns the transmission network. The SO in these systems is generally called as Transmission System Operator (TSO). In the case of a SO being completely neutral of every other activity except coordinate, control and monitor the system, it is generally called as Independent System Operator (ISO).

7. **Customers**: A customer is an entity, consuming electricity. In a completely deregulated market where retail sector is also open for competition, the end customer has several options for buying electricity. It may choose to buy electricity from the spot market by bidding for purchase, or may buy directly from a Genco or even from the local retailing service company. On the other hand, in the markets where competition exists only at the wholesale level, only the large customers have privilege of choosing their supplier.

4. How the utility market in different countries is classified? Categorize the market based on their percentage utility.

The US

The US electric utilities, from the very beginning were privately owned and worked in a vertically integrated fashion. The developed countries like US had well functioning and efficient electricity systems. However for some systems, so long as consumers were concerned, they were not satisfied with the rising costs of electricity. For some other systems, utility management found that running the system was not viable due to low tariff. In some systems, pressure from smaller players to open up the business for competition played a major role. By and large, deregulation took place in developed countries by pressure to reduce costs while simultaneously increasing competitiveness in the market.

Existence of market power shows the signs of deviation from the prefect competition. In general, market power is referred to as ability of market participants to profitably maintain the market price above or below the competitive level for a significant period of time. To tackle the situation, an the indirect regulatory intervention in the form of market design rules is needed. Thus, as mentioned earlier, deregulation does not mean ceasing to have rules. It is the 'restructuring' of the power business framework. More rigorous treatment to these issues is given in further chapters.

The UK

The transformation of the British power sector proceeded along three paths in 1990. First, the traditional industry was unbundled both vertically and horizontally. High-voltage transmission assets were transferred to a new National Grid Company (NGC). Coal and oil fired units were divided among two companies National Power and PowerGen. Nuclear Electric retained control of all nuclear units. At the outset, National Power had 52 percent of total generating capacity, PowerGen had 33 percent, and Nuclear Power had the remaining 15 percent. The second set of changes involved ownership. Both National Power and PowerGen became private companies in 1991, whereas the difficulties associated with nuclear power resulted in continued government ownership of all nuclear units. Approximately 30 percent of shares in National Power and PowerGen were sold to the public,an equal amount to foreign and institutional investors. The remaining 40 percent was held by the government until 1995. The third set of changes sought to open the system to competition, wherever possible, while continuing necessary regulations. Vertical and horizontal restructuring of power generation was based on the assumption that generation had become workably competitive and would become increasingly so with new market entrants.

A report on reform process was floated by the regulator in 2001 which stated that wholesale electricity prices had not fallen in line with reductions in generators' input costs and that a lack of supply side pressure and demand side participation; and inflexible governance arrangements had prevented reform of the arrangements.

The Nordic Pool

The reforms in Nordic countries were inspired by the electricity market reforms in England and Wales in 1989, as well as by widely held beliefs that increased competition would raise power industry efficiency to the benefit of consumers. Norway was first amongst the Nordic countries to liberalize its electricity market in 1991, but without privatization. The Norwegian electricity sector remains almost entirely in public hands. Rather than implement national reforms, the other Nordic countries chose to reform by merging with the existing Norwegian market, Sweden joining the expanded Nordic pool in 1996, Finland in 1998 and Denmark in 1999.

The Developing Countries

The case of developing countries is different from that of other countries. In these countries, the electricity supply is treated as a social service rather than a market commodity. The ownership of the power sector in these countries is directly under the governments of respective countries. These state owned-controlled systems have led to the promotion of inefficient practices over a period. The power sectors of these countries are marked by supply shortages. There has been an inability to add to the generating capacity. The subsidies and high transmission and distribution losses are the major concerns before these systems. Another consequence of state control over electric utilities was the high level of overstaffing.

The inability to raise funds for capacity addition invited financial support from international financial institutions like World Bank. These institutions mandated opening of the power sector for private companies which were contracted under build, own, operate and transfer (BOOT) scheme.

5. Explain the Various market models are used in deregulated environment.

As mentioned earlier, unbundling of the conventional vertically integrated power system creates groups of various commercial and technical activities. Since one of the major aims of deregulation is introduction of competition, it is worthwhile to explore every avenue where competition can be introduced. Eventually, competition provides a choice for entities to choose another entity or a group of entities to do a profitable transaction. In electricity parlance, either the load or an entity representing a group of loads gets a choice to select its energy provider, or there may exist some mechanism which would cater to the electrical energy needs of these loads at a competitive level.

The former mechanism essentially requires bilateral involvement of the entities who wish to get into a power buy and sell contract. In this, the sellers and buyers mutually agree upon the terms and conditions, including the price and time of delivery. A repetitive bilateral interaction between buyers and sellers may lead to an equilibrium point where everyone is happy. Alternatively, a similar result would be obtained if a common exchange for the commodity is set up, where, buyers and sellers, instead of interacting with each other, communicate their expectations to this marketplace. This represents a simultaneous market clearing process and a common market price of electrical commodity.

While moving from a vertically integrated structure to a competitive one, various policy and structural issues crop up. One of the important concerns is regarding the entity that should be allowed to take part in competitive activity. Similarly, issue of rearrangement of various elements of power system, when a new set of rules is introduced to buy and sell power, also needs to be addressed. It is obvious that the commercial arrangements and virtual boundaries between various functional entities can take many shapes and forms. Consequently, various models can be classified according to the levels at which the entities are given the choice of buying or selling electricity.

Various trading models can be proposed based on the above discussion. The choice of choosing a model is a policy decision and is dominated by various prevailing conditions. They need to be accounted for before making structural changes. In [1], four basic models of industry structure are suggested. These are:

1. Monopoly model
2. Single buyer mode
3. Wholesale competition model

4. Retail competition model

Every model needs different amount of structural change and rearrangements of functions in the industry. These models are discussed next.

Monopoly Model

In this model, a single entity takes care of all the businesses such as generation, transmission and distribution of electric power to the end users. One of the versions of this model is shown in Figure 3.1(A). In this, a single utility integrates the generation, transmission and distribution of electricity. Usually (but not necessarily), in this kind of model, the monopoly lies with the Government. It is quite natural that this kind of model should have strict regulation in order to protect end consumers against monopoly. Most of the electric power systems followed this model prior to deregulation.

Another version of the monopoly model is shown in Figure 3.1(B). In this model, generation and transmission are integrated and operated by a single utility and it sells the energy to local distribution companies, which themselves represent local monopolies.

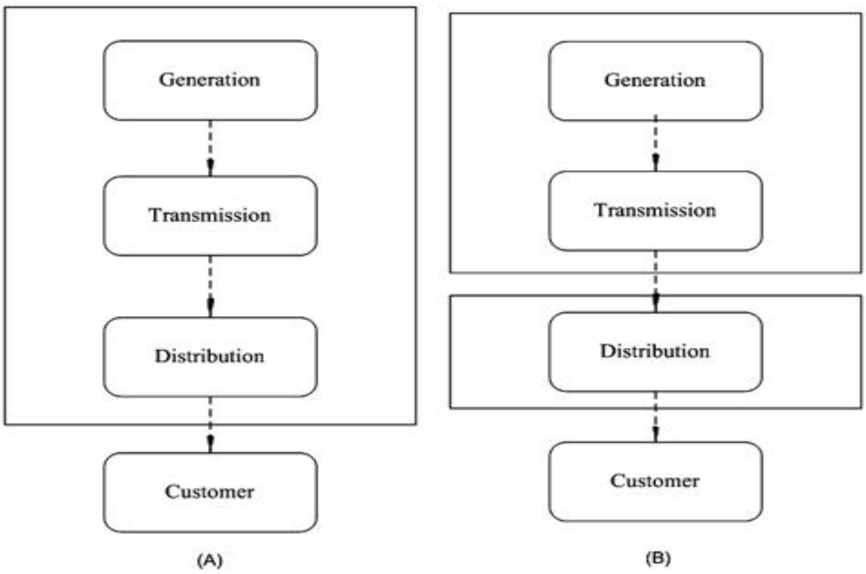


Figure 1.1: Two different versions of monopoly model

Single Buyer Model

In this model, as shown in Figure 3.2, there is competition in the wholesale sector, i.e., generation.

Here, the single buyer agency buys power from Independent Power Producers (IPPs) in addition to its own generation. The power purchasing agency in turn sells it to state distribution utilities or distribution companies in the service area. All power generated by generating companies (Gencos) must be sold only to a purchasing agency and not to any other agency. Distribution companies (Discoms) are only able to purchase from the single buyer agency. They do not have a choice of choosing their power supplier.

In this model, sales from power pool to retailers take place at a pre-set tariff price. The single buyer or the existing utility makes a long term contract with IPPs. A contract is necessary because, without it, a generator would be reluctant to invest large amounts of capital in a generating plant. The contracts are generally of life-of-plant type, indicating sale of all capacity of generating units for its lifetime.

Figure 3.3 shows another version of this model, which has further evolved from the original single buyer model. In this model, the single buyer does not own any generation and buys all the power from IPPs. The distribution and retail activities are also disaggregated. This model has an advantage of introducing some competition between generators without the expense of setting up a competitive market. The tariff set by the purchasing agency must be regulated because it has monopoly over the Discos while monopsony over the IPPs. The single buyer model is looked upon as a way of attracting private participation in the generation sector, especially in the developing countries.

In this model, transmission and distribution network can be owned and operated by State and Regional transmission utilities. Inter-state tie line should be sufficient to maintain a loose regional power pool. Merits and demerits of this model are as follows:

Merits:

- Private participation in power generation
- Introduction of some competition without expensive set up for a competitive market.

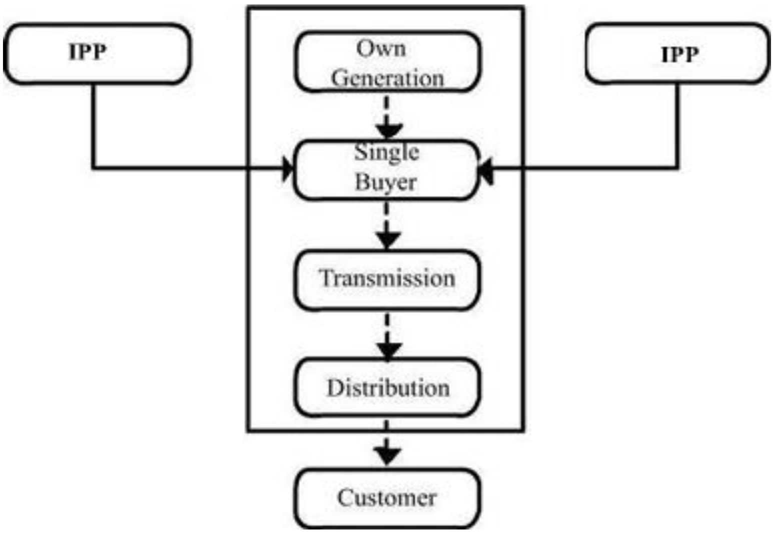


Figure 1.2: Single buyer model

Demerits:

- Long term contracts. Setting up a contract is problematic.
- No true competition.
- Price is not decided by demand-supply interaction.
- End consumers' price is regulated .

Wholesale Competition Model

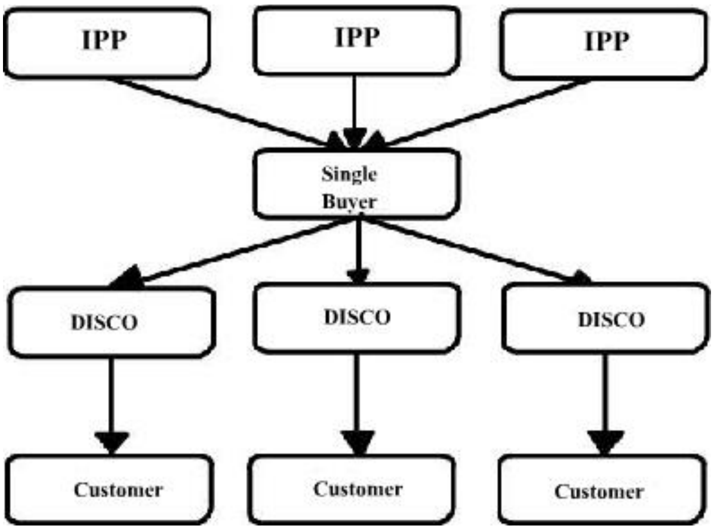


Figure 1.3: Single buyer model with only IPPs

This model is one step closer towards competition. There is an organized market in which the generators can sell their energy at competitive rates. The market may be organized either by a separate entity or may be run by the system operator itself. There is not much choice for the end user. The end user is still affiliated to the Discom or retailer working in that geographical area of operation. The large customers or the bulk customers, so to say, are privileged to choose their energy provider. However, the definition of bulk customer is a subjective matter and changes from system to system.

This model, as shown in Figure 1.4, provides the choice of supplier to Discoms, along with competition in generation. Implementation of this model requires open access to the transmission network. Also, a wholesale spot market needs to be developed. Since this model permits open access to the transmission wires, it gives the IPPs to choose an alternative buyer. Discoms can purchase energy for their customers either from a wholesale market or through long term contracts with generators.

The customers within a service area still have no choice of supplier. They will be served by a Discom in their area. With this model, the Discoms are under Universal Service Obligation (USO), as they have monopoly over the customers. They own and operate the distribution wires. The transmission network is owned and maintained either by government and/or private transmission companies. System operators manage the centrally accomplished task of operation and control.

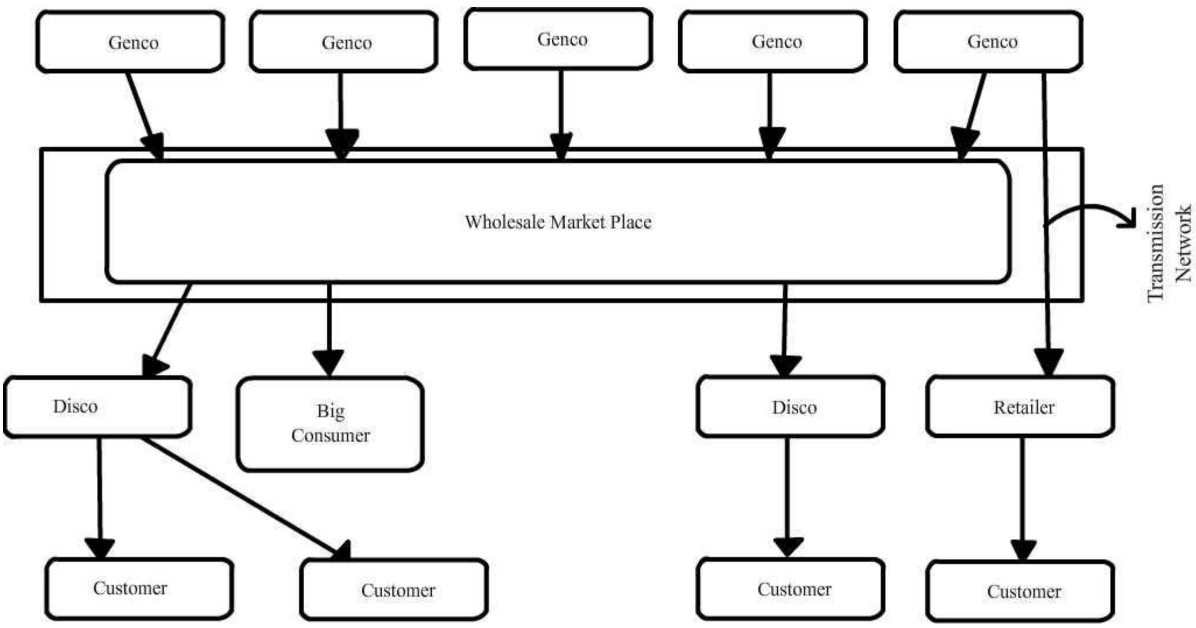


Figure 1.4: Wholesale Competition Model

The model provides a competitive environment for generators because the wholesale price is determined by the interaction between supply and demand. In contrast, the retail price of electrical energy remains regulated because the small consumers still do not have a choice for their supplier. The distribution companies are then exposed to vagaries of the wholesale price of the commodity. The merits and demerits of this model are as follows:

Merits:

- Choice of seller provided for Discoms and bulk consumers.
- The buyers and sellers can make forward contracts or buy from a wholesale marketplace.
- The price is decided by interaction between demand and supply. Hence, indicates truly competitive price.

Demerits:

- The end consumer still doesn't have a choice. It buys power from the affiliated Discom.
- Rates for end consumers are regulated rather than competitive.
- Discoms face competition at wholesale level, while their returns are regulated.
- Structural and institutional changes required at wholesale level.

Retail Competition Model

In this model, as shown in Figure 1.5, all customers have access to competing generators either directly or through their choice of retailer. This would have complete separation of both generation and retailing from the transport business at both transmission and distribution levels. Both, transmission and distribution wires provide open access in this model. There would also be free entry for retailers. In this model, retailing is a function that does not require the ownership of distribution wires, although, the owner of distribution wires can also compete as a retailer.

This model is a multi-buyer, multi-seller model and the power pool in this model acts like an auctioneer. It behaves like a single transporter, moving power to facilitate bilateral trading and this is achieved through an integrated network of wires. In this pooling arrangement, there is a provision for bidding into a spot market to facilitate merit order dispatch. The pool matches the supply and demand and determines the spot price for each hour of the day. It collects money from purchasers and distributes it to producers.

The advantage of this model over monopoly utilities is that competition is introduced in both wholesale and retail areas of the system. This model is supposed to be a truly deregulated power market model. The retail price is no longer regulated because small consumers can change their retailer for better price options. This model is economically efficient as the price is set by interaction of demand and supply. In wholesale competition model, with relatively few customers, all of them regulated Discoms, a spot market can be preferable but not essential.

However, in retail competition model, spot markets become essential, since contractual arrangements between customers and producers are carried out over a network owned by a third party. In retail competition model, metering becomes a major problem. If the number of customers is increasing and metering capability for all the customers is not sufficient, it may create logistical problem and provoke disputes.

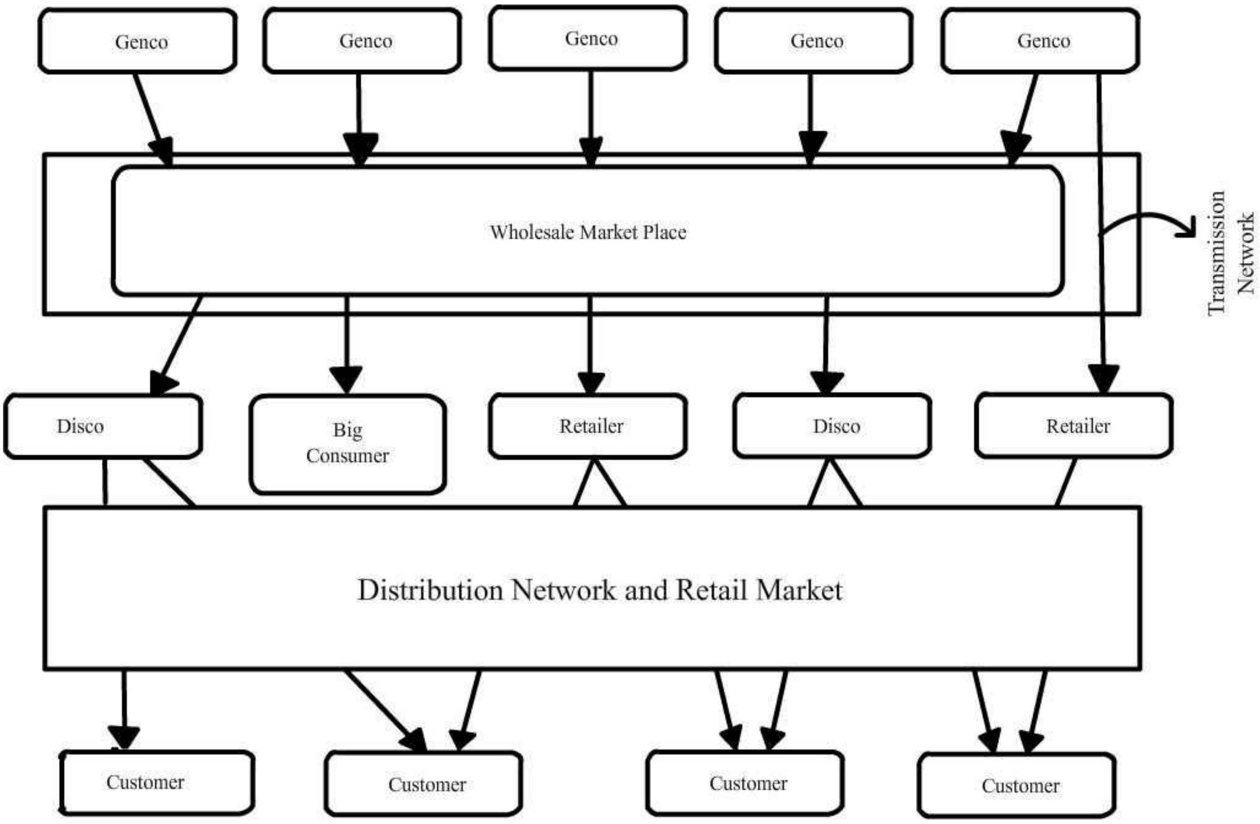


Figure 1.5: Retail Competition Model

Merits:

- Supposed to be 100% deregulated model.
- Every consumer has a choice of buying power.
- The price is decided by interaction of demand and supply. Hence, it is truly competitive price.
- There is no regulation in energy pricing.

Demerits:

- Need constitutional and structural changes at both, wholesale and retail level.
- Extremely complex settlement system due to large number of participants.
- Requirement of additional infrastructural support.

What is meant by bilateral Market?

Bilateral trading generally involves two parties interacting with each other: a buyer and a seller. The characteristic of bilateral trades is that the price of a transaction is set independently by the parties involved. There is no market clearing price as such. Since, electricity cannot be stored, it creates a wide fluctuation in the spot price. Forward contracts provide generators and loads with a means of hedging their exposure to fluctuations in the spot price of electricity. The generators can negotiate a price for their output prior to the moment of producing it. Similarly, properly structured forward contracts provide buyers with the ability to lock in a fixed price for a fixed quantity of electricity well in advance of delivery and consumption. Indeed, if a buyer's actual energy usage matches its forward market purchases, it can achieve a benefit of complete price certainty in the face of real time price volatility.

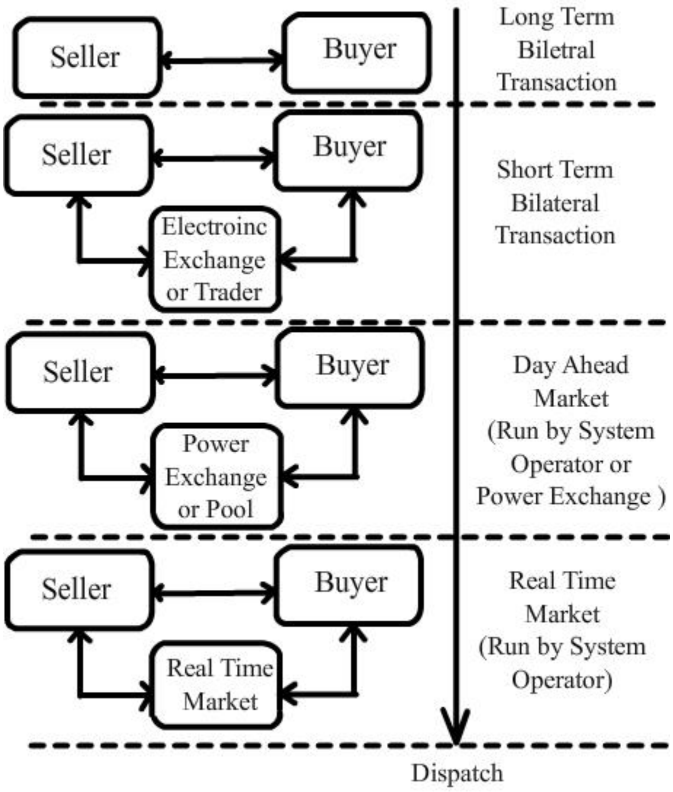


Figure : Seller buyer interaction based on timeline

Depending upon the quantity of power and time, the buyers and sellers resort to different forms of trading:

- Long Term Contracts: This type of trade generally includes contract for a large amount of power for a long time period. These types of contracts are negotiated privately and the terms and conditions are such that they suit both the parties involved in the transaction.
- Trading Over The Counter: These transactions involve smaller amounts of energy to be delivered. For example, the amount of energy to be delivered during different periods of the

hour, day, etc. This type of trading has much lower transaction costs and is used by producers and consumers to refine their positions before real time.

- Electronic Trading: In this, participants can enter offers to buy energy and bids to sell energy directly in a computerized marketplace. The participants can observe the quantities and offers/ bids submitted by all participants, but do not know the party involved. The software in the exchange couples the matching offers. It checks whether for a newly entered bid, if there is matching offer whose price is greater than or equal to price of the bid. If no match is found, the bid is added to the list of outstanding bids until a new offer matches it. Otherwise, it lapses after the market is closed. The same process is repeated after a new bid is entered. There is no market clearing price as such.

6. Explain in detail about spot market?

As we have discussed in module 2, a market for any commodity provides an environment for buyers and sellers to interact and agree on transactions, generally, the quantity and price. These interactions progressively lead to an equilibrium point at which the price clears the market, that is, the supply is equal to demand. If electrical energy is to be traded according to a mechanism in which the buyers and sellers are free to interact individually, the equilibrium between the production and the consumption can be set through repetitive interaction. In this scheme of attaining equilibrium, the consumers make an estimation of their consumption before entering into a contract. The generators schedule the production of their units to deliver at the agreed time the energy that they have agreed to sell. However, in practice, neither party can meet its contractual obligation with perfect accuracy because, for example, from a load's point of view, the actual demand of a group of customers is never exactly equal to the value forecasted. Changes in weather and due to some other externalities, the day ahead or before real time estimation of load consumption can have deviation from that done few months or years back, while doing the contract. Also, unforeseen problems may prevent generating units from delivering the contracted amount of energy.

It can be concluded that, while a large proportion of the electrical energy can be traded through an unmanaged open market in terms of forward contracts, such a market may not necessarily lead to an equilibrium that replicates real time scenario. Thus, an intermediate stage is necessary, where a managed spot market can provide a mechanism for balancing load and generation. This market should supersede the open energy market as the time of delivery approaches. Its function is to match residual load and generation by adjusting the production of flexible generators and curtailing the demand of willing customers.

In many real life markets, more than 80% of the energy traded is through the forward or bilateral contracts. The rest is traded through the spot market. In a multi-settlement market (typically practiced in some of the markets in USA), the spot market is sometimes made of two markets: Day Ahead (DA) market and a Real Time (RT) market. The DA market is run for each hour or half hour of the next day. The RT market is always run by a system operator, while the day-ahead market may or may not be run by the system operator. In both cases, the general principle of market clearing is the same. This and other related issues are discussed next.

Spot Market Clearing

For the sake of understanding, let us assume that the market is run by an entity called Power Exchange (PX). The power exchange operates much like a stock exchange. The buyers and sellers enter their needs into the power exchange. For example, a buyer would say, "I need up to 20 MW between 1600 hours and1700 hours IST. I would pay INR 3.5/ kWhr", whereas, the seller would enter his demand as, "I have 100 MW and would like to sell it at INR 4/ kWhr".

When they transact with the power exchange, buyers and sellers are really talking to the marketplace and not the individual buyers and sellers. As in a stock exchange, the power exchange constantly updates and posts a market clearing price (MCP), which is the current price at which the transactions are being done. Note that when buyers and sellers communicate with the power exchange, they don‘t know whom they are dealing with. The general step by step process of settling this market is as follows:

1. Generating companies submit bids to supply a certain amount of electrical energy at a certain price for the period under consideration. Usually, the period is an hour or half an hour. The bids are ranked in order of increasing price. From this, a curve that shows bid price as a function of bid quantity is built, which is commonly known as supply curve. Supply curve is a plot with price on y axis and quantity on x axis.
2. Similarly, demand curve is established by asking consumers to submit offers specifying quantity and price and ranking these offers in decreasing order of price. If the load is willing to adjust its consumption with price, the load is said to have demand elasticity. If the load is firm, the demand curve will take the form of a vertical line with x axis intersection indicating total cumulative firm demand.
3. The intersection of supply and demand curves represents the market equilibrium. At this point, the supply matches the demand. This price is known as Market Clearing Price (MCP) or System Marginal Price (SMP). All the bids submitted at a price lower than or equal to the market clearing price are accepted and the generators are scheduled for that much amount of power for that particular time period under consideration. Similarly, all the offers submitted at a price greater than or equal to the market clearing price are accepted.

4. As for settlement, the generators are paid this MCP for every MWh they are scheduled for, while loads pay the MCP for every MWh they are cleared for.

PART A

1. Define the term Deregulation. . (Nov 2013)(April/May 2012)(Nov 2011)

Deregulation in power industry is restructuring of rules and economic incentives that government set up to control and drive the electric power industry. Deregulation often involves unbundling which refer to disaggregating an electric utility service in to basic component separately for safe with separate rates for each component.

2. How Deregulation affects market?

The establishment of the energy markets has brought a new dimension to the topic of power systems. Economics designs different forms of energy markets according to the characteristics of the electricity sector in a particular country. Most countries also learn from the lesson of their precedents.

3. How OPF is useful in integrated market?

In traditional power systems, the utilities are mostly owned by governments. Vertically integrated utilities typically own generation, transmission and distribution over a wide area. Each utility has one or more control centre's that maintain security and reliability of a specific region.

4. What are the two benefits results from deregulation?

The potential benefits resulting from deregulation are two. First, the advance of technology makes low cost power plants owned by independent power producers very efficient. These independent power producers would not emerge without the reform. Second, unbundling the services may result in fairer tariffs being assigned to individual services

5. Why price gap regulation is adopted?

Price- gap regulation is adopted as an attempt to reduce the power of natural monopolies in sector that not or cannot acquire full competition.

6. What are the motives of privatization?

The motives of privatization include the reduction of central government's role in economic decision making, forcing privatized companies to become more accountable to owners and encouraging the creation of a shareholder society through widespread stock ownership.

7. What are reform motivations? (April 2013, November 2012)

The reform, motives for an efficient operation to provide profit making and to eradicate inefficiency through competition.

8. Define natural monopoly?

Natural monopoly refers to a situation where one firm can produce a given level of output at a lower total cost that includes combination of multiple films. Natural monopolies occur in industries that exhibit decreasing average long-run costs due to size. i.e. economies of scale

9. What is economics theory?

According to economic theory, a public monopoly governed by regulation is justified when an industry exhibits' natural monopoly characteristics

10. What are the types of markets?(Nov/Dec 2014)

The two main types of model are pool model and open access model.

Based on contractual arrangements the market can be classified into the following

1. Monopoly model
2. Single buyer mode
3. Wholesale competition model
4. Retail competition model

11. What is meant by wheeling? (Nov/Dec 2014)

Wheeling is the transmission of electrical energy from a buyer to a seller, through transmission or distribution lines owned by a third party. Wheeling can occur between two adjacent utilities, or between utilities in different states. Under existing law, qualifying facilities may only transmit their output to their local utility. Wheeling" allows utility areas with too much supply to transmit excess power to other utilities with too much demand. The ultimate goal is to move the least-cost power to where it is needed, maximizing efficiencies. If wheeling is an option, a utility can determine if it is cheaper to build a new electric generation facility or buy power from another service area

12. Define the role of ISO (April 2015) (April/May 2012)(Nov 2011) (April/MAy 2014)

1. System security: Operator must assure that the power system continues to operate in a stable, economical manner.

2. Power delivery: The operator should provide the power transportation services requested of it by buyers and sellers.
3. Transmission pricing: System operator must determine and post the prices for transmission usage, offer to reserve or sell usage track, bill and settle with users. And pass on revenues to transmission owners.
4. Service quality assurance: The system operator must assure the quality of service it provides.
5. Promotion of economic efficiency and equity: The overall operations of the system operator should obey economic efficiency and also it should have fairness and equity in it's dealing and should not benefit only some players in the system.

13. Define pool markets. (April 2015)

The Uk model is an example of this type. It is monopsony i.e. there is only a single buyer for all the energy generated by gencos.The buyer here is a Poolco,which also operates the system.So.UK Poolco is responsible for inviting bids for energy and deciding the energy price for a particular period in future markets like day ahead market.

14. What is spot market concept? (April/May 2014)

The spot market includes day-ahead and real-time market similarly, drawing line between spot and forward markets are not clear. According to one definition, all the markets before the real-time market can be classified as forward markets. This is because, in many forward markets, including day-ahead market, traders need not own a generator to sell power. If power is not delivered in real time, then the supplier must purchase replacement power at the real time rate and fulfill the contract. A customer who buys power in a forward market will receive either electricity delivered by the seller or a financial compensation. Any power that is sold in the day-ahead market, but not delivered in real time, is deemed to be purchased in real time at the real time price of energy. The combination of day-ahead and real-time market is popularly known as multi-settlement market system in USA.

15. List out the process involved in reform motivations (April 2013)

1. Tecchnological innovation improved the efficiency of small units for gas turbines, combined cycles, over that of larger ones.

2. Improvements in materials, including new high temperature metals, special lubricants, ceramics and carbon fiber permit vastly stringer and less expensive small machinery to be built.

3. Computerized control system has been developed that often reduce the number of on-sight personnel to zero.

4. Data communication and off site monitoring systems can control the units from remote operations centres, where one central operator can monitor a dozen units at various sites .

16. Mention the transitions faced towards deregulated markets. (April 2013)

1. Privitisation

2. Cost is expected to drop

3. Customer focus will improve

4. Encourages innovation

Question Bank

1. Explain the need of deregulation of electric utilities and the fundamentals of deregulated markets.(Nov/Dec 2014)
2. List the type of ISO and discuss about the role of ISO.(Nov/Dec 2014)
3. Explain in detail about structure for central utility model.(Nov 2013)
4. Describe the role of ISO in electric utility market services. .(Nov 2013)
5. Briefly explain the fundamentals of deregulated markets. (April 2015)
6. Explain the Australia deregulated electricity markets in brief. (April 2015)
7. Explain the about the Bilateral markets and pool markets. (April/May 2014)
8. Power system restructured model and various entities in it(April/May 2014)
9. Explain the Australia and Asia deregulated electricity markets (April/May 2014)
10. Explain different auction methods employed in electricity markets. (April/May 2014)(Nov 2011)
11. Explain in detail the role of ISO in electricity markets. (April/May 2012)
12. Explain the reform motivations and fundamentals of deregulated market. (April 2013)
13. Describe ISO components, Types and role in power system. (April 2013)(Nov 2011)
14. By using structure arrangement, explain the trading of power pool with bilateral contracts. (Nov 2011)

DEPARTMENT OF ELECTRICAL & ELECTRONICS ENGINEERING

Subject Name: **POWER SYSTEM RESTRUCTURING AND DEREGULATION**

Subject Code: **EE E89**

Prepared by:

1. Mrs.S.Punitha , AP/EEE

2. Mr.V.Malarselvam, AP/EEE

Verified by: *Approved by:*

UNIT – II

TECHNICAL CHALLENGES

Total Transfer Capability – Limitations - Margins – Available transfer capability (ATC) – Procedure - Methods to compute ATC – Static and Dynamic ATC – Effect of contingency Analysis – Case Study. Concept of Congestion Management – Bid, Zonal and Node Congestion Principles – Inter and Intra zonal congestion – Generation Rescheduling - Transmission congestion contracts – Case Study.

PART-B

1. Write short notes on total transfer capability, CBM and TRM.

Total Transfer Capability (TTC)

It is defined as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of the specific set of defined pre and post contingency system conditions.

Transmission Reliability Margin (TRM)

It is defined as the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Capacity Benefit Margin (CBM)

It is defined as the amount of transmission transfer capability reserved by load serving entities to ensure that the interconnected systems do meet generation reliability requirements.

The NERC report brings out the difference between “transfer capability” and “transmission capacity”. According to this report, the ‘capacity' specifically mentions the rating of the equipment, for example, the ampacity of the conductor. On the other hand, the ‘capability' depends upon generation, customer demand and the conditions in a transmission system for the given time period. Thus, the ‘capacity' of a circuit may not change much from time to time. However, the ‘capability' always changes with the time by virtue of changes in the system condition.

The ability of the network system to reliably deliver power is limited by physical and electrical characteristics of the system. These limits are: Thermal, Voltage and Stability. During the varying conditions of power system, one of these limits plays a major role in deciding the transfer capability. Determining which limit is binding during a particular time is a challenging task and makes computation of ATC an involved task.

Many methods have been suggested to calculate the ATC. The methods differ on the basis of the power flow model being employed, the system aspects considered, the compelling limits under consideration and some other factors. However, a broad way of classifying methods is based on the type of limit considered, i.e., Thermal limit, Voltage limit or the Angular stability limit.

The **DC power flow** methods take into consideration only the thermal limits. The **AC Optimal power flow** (OPF) methods consider thermal as well as voltage limits. Then, there is another version called **Continuation power flow method** (CPF). It considers a series of power system solutions to be solved and tested for limits. The amount of transfer is gradually increased from the base case until a binding limit is encountered. Ejebe et al. have described a method based on continuation power flow, incorporating limits of reactive power flows, voltage limits, as well as voltage collapse and line flow limits. Christie et al. have proposed a method based on DC **power transfer distribution factors** (PTDF). This utilizes DC load flow based formulation, and computation of simultaneous ATC has also been considered using an optimization based approach.

ATC Calculation using PTDF and LODF based on DC Model

One way of calculating ATC from node A to node B is to use DC load flow (explained later) repetitively by increasing the amount of transaction until a limit of any of the corridor is reached. However, this is computationally inefficient. Instead, the Power Transfer Distribution Factor (PTDF) can be used to calculate the maximum allowable flow for a given pair of injection and take-off points. It is also necessary to consider the effects of contingencies like line outages. This can be achieved using Line Outage Distribution Factor (LODF). Let us first see the details of DC load flow model.

DC Load Flow Model

Following are the assumptions when DC model is employed instead of AC model:

- Voltage magnitudes are constant.
- Only angles of complex bus voltages vary.
- The variation in angle is small.
- Transmission lines are lossless.

These assumptions create a model that is a reasonable first approximation for the real power system, which is only slightly nonlinear in normal steady state operation. The model has advantages for speed of computation, and also has some useful properties like linearity and superposition.

With these assumptions, power flows over transmission lines connecting bus i and bus j is given as:

$$P_{lm} = \frac{1}{x_{lm}}\left(\theta_l - \theta_m\right) \quad \text{.......................................(4.1)}$$

Where,

x_{lm} line inductive reactance in per unit

θ_l phase angle at bus l

θ_m phase angle at bus m

The total power flowing into the bus i, Pi, is the algebraic sum of generation and load at the bus and is called a bus power injection. Thus,

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}\left(\theta_i - \theta_j\right) \quad \text{.......................................(4.2)}$$

This can be expressed in a matrix form as:

$$\begin{bmatrix} P_1 \\ M \\ P_n \end{bmatrix} = \begin{bmatrix} B_X \end{bmatrix} \begin{bmatrix} \theta_1 \\ M \\ \theta_n \end{bmatrix} \quad \text{.......................................(4.3)}$$

Where, the elements of the susceptance matrix BX are functions of line reactances . One node is assigned as a reference node by making its angle zero and deleting corresponding row and column in $\left[B_X\right]$ matrix. Thus,

$$\left[X_{init}\right] = \left[B_{X,reduced}\right]^{-1}$$

$$\text{...(4.4)}$$

The dimension $[X_{init}]$ of obtained is $(n-1 \times n-1)$. Let us augment it by adding zero column and row corresponding to reference bus. The angles in equation 4.3 can be found out as

$$\begin{bmatrix} \theta_1 \\ M \\ \theta_n \end{bmatrix} = [X] \begin{bmatrix} P_1 \\ M \\ P_n \end{bmatrix} \quad \text{....................................(4.5)}$$

Thus, power flow over line lm can be found out using equation 4.1.

Power Transfer Distribution Factor (PTDF)

From the power transfer point of view, a transaction is a specific amount of power that is injected into the system at one bus by a generator and drawn at another bus by a load. The coefficient of linear relationship between the amount of a transaction and flow on a line is represented by PTDF. It is also called sensitivity because it relates the amount of one change - transaction amount - to another change - line power flow.

PTDF is the fraction of amount of a transaction from one bus to another that flows over a transmission line. $PTDF_{lm,ij}$ is the fraction of a transaction from bus i to bus j that flows over a transmission line connecting buses l and m.

$$PTDF_{lm,ij} = \frac{\Delta P_{lm}}{P_{ij}} \quad \text{....................................(4.6)}$$

Calculation of PTDF Using DC Model

Suppose there exists only one transaction in the system. Let the transaction be of 1 MW from bus i to bus j. Then, the corresponding entries in equation 4.7 will be: $P_i = 1$ and $P_j = -1$. All other entries will be zero. From equation 4.5, we get

$$\theta_l = \begin{bmatrix} X_{l,1} & L & X_{l,n-1} \end{bmatrix} \begin{bmatrix} 0 \\ +1 \\ M \\ -1 \\ 0 \end{bmatrix}$$

....(4.7)

Similarly,

$$\theta_m = \begin{bmatrix} X_{m,1} & L & X_{m,n-1} \end{bmatrix} \begin{bmatrix} 0 \\ +1 \\ M \\ -1 \\ 0 \end{bmatrix}$$

....(4.8)

Thus,

$$\theta_l = X_{li} - X_{lj}$$ ....(4.9)

$$\theta_m = X_{mi} - X_{mj}$$ ....(4.10)

Using equations 4.9, 4.10 and 4.1, the PTDF can be calculated as

$$PTDF_{lm,ij} = \frac{X_{li} - X_{mi} - X_{lj} + X_{mj}}{x_{lm}}$$ ....(4.11)

x_{lm} Reactance of transmission line connecting buses l and m

X_{li} Entry lth row and ith column of the bus reactance matrix X

The change in line flow associated with a new transaction is then

$$\Delta P_{lm} = PTDF_{lm,ij} P_{ij}$$ ....(4.12)

Where,

l and m buses at the ends of the line being monitored

i and j from and to bus numbers for the proposed new transactions

P_{ij} New transaction MW amount

ATC calculation Using PTDF

ATC is determined by recognizing the new flow on the line from node l to node m, due to a transaction from node i to node j. The new flow on the line is the sum of original flow P_{lm}^{0} and the change.

$$P_{lm} = P_{lm}^{0} + PTDF_{lm,ij} P_{ij} \qquad \text{.........(4.13)}$$

Where, P_{lm}^{0} is the base case flow on the line and P_{ij} is the magnitude of proposed transfer. If the limit on line lm, the maximum power that can be transferred without overloading line lm, is P_{lm}^{max} , then,

$$P_{ij,lm}^{max} = \frac{P_{lm}^{max} - P_{lm}^{0}}{PTDF_{lm,ij}} \qquad \text{.........(4.14)}$$

$P_{ij,lm}^{max}$ is the maximum allowable transaction from node i to node j constrained by the line from node l to node m. ATC is the minimum of the maximum allowable transactions over all lines.

Using the above equation, any proposed transaction for a specific hour may be checked by calculating ATC. If it is greater than the amount of the proposed transaction, the transaction is allowed. If not, the transaction must be rejected or limited to the ATC.

$$ATC_{ij} = \min\left(P_{ij,lm}^{max}\right) \quad \forall lm \qquad \text{.........(4.15)}$$

Using the above equation, any proposed transaction for a specific hour may be checked by calculating ATC. If it is greater than the amount of the proposed transaction, the transaction is allowed. If not, the transaction must be rejected or limited to the ATC.

Numerical Example of ATC Calculation Using PTDF

Consider a sample 3 bus system as shown in Figure 4.2.

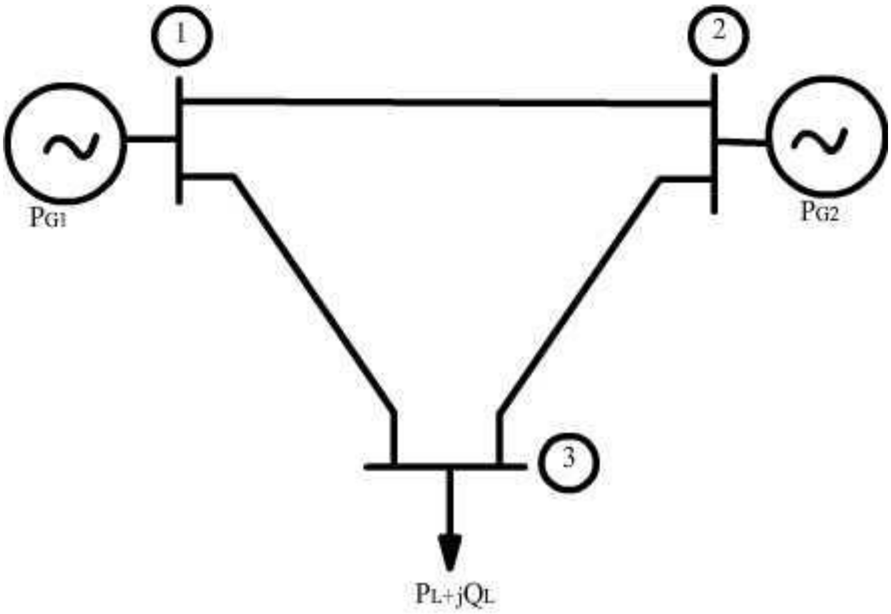


Figure 4.2: Sample 3 bus system

Bus No	Generation	Load (MW)
1	200	0
2	700	100
3	0	800

Table 4.2: Bus data for sample system

From Bus	To Bus	Line Reactance (pu)	Max. Power capacity (MW)
1	2	0.1	600
2	3	0.033	200
3	3	0.1	600

Table 4.3: Line data for sample system

If we treat bus 1 as the reference bus, then the matrix X is obtained as

$$YBUS = \begin{bmatrix} -j30 & j10 & j20 \\ j10 & -j25 & j15 \\ j20 & j15 & -j35 \end{bmatrix}$$

....(4.16)

$$X = \begin{bmatrix} 0 & 0 & 0 \\ 0 & 0.05385 & 0.02308 \\ 0 & 0.02308 & 0.03846 \end{bmatrix}$$

....(4.17)

Now let us calculate PTDF for a transaction between bus 1 and 3. Thus, PTDF on various corridors using equation 4.11 can be given as:

$$PTDF_{12,13} = \frac{X_{11} - X_{21} - X_{13} + X_{23}}{x_{12}} = 0.23077$$

....(4.18)

$$PTDF_{13,13} = \frac{X_{11} - X_{31} - X_{13} + X_{33}}{x_{13}} = 0.76923$$

....(4.19)

$$PTDF_{23,13} = \frac{X_{21} - X_{31} - X_{23} + X_{33}}{x_{23}} = 0.23077$$

....(4.20)

Similar calculations are done for transaction between buses 2 and 3, the PTDFs are given as

$$PTDF_{12,23} = \frac{X_{12} - X_{22} - X_{13} + X_{23}}{x_{12}} = -0.3077$$

....(4.21)

$$PTDF_{13,23} = \frac{X_{12} - X_{32} - X_{13} + X_{33}}{x_{13}} = 0.3077$$

....(4.22)

$$PTDF_{23,23} = \frac{X_{22} - X_{32} - X_{23} + X_{33}}{x_{23}} = 0.6923$$

....(4.23)

Now suppose, there are two transactions, one of 200 MW between buses 1 and 3, and the other of 600 MW between bus 2 and 3. Then, the power flow on all corridors due to these transactions can be given as:

$$\begin{bmatrix} P_{12} \\ P_{13} \\ P_{23} \end{bmatrix} = \begin{bmatrix} 0.23077 & -0.3077 \\ 0.76923 & 0.3077 \\ 0.23077 & 0.6923 \end{bmatrix} \begin{bmatrix} 200 \\ 600 \end{bmatrix} = \begin{bmatrix} -138.46 \\ 338.46 \\ 461.54 \end{bmatrix}$$
....(4.24)

The above equation establishes the base case flows of a system with two transactions in place. Now let us calculate ATC for transferring power between bus 1 and 2 and also between bus 2 and 3. In order to calculate ATC, we make use of equations 4.11, 4.12 and 4.13. First let us calculate ATC between buses 1 and 3. Using equation 4.12,

$$P_{12,13}^{max} = \frac{\left(P_{12}^{max} - P_{12}^{0}\right)}{PTDF_{12,13}} = \frac{|-600-138|}{0.23077} = 3197MW$$
....(4.25)

$$P_{13,13}^{max} = \frac{\left(P_{13}^{max} - P_{13}^{0}\right)}{PTDF_{13,13}} = \frac{|200-338|}{0.76923} = 179MW$$
....(4.26)

$$P_{23,13}^{max} = \frac{\left(P_{23}^{max} - P_{23}^{0}\right)}{PTDF_{23,13}} = \frac{|600-462|}{0.23077} = 598MW$$
....(4.27)

Using equation 4.13, ATC between buses 1 and 3 is given as 179 MW. Similarly, for ATC between buses 2 and 3,

$$P_{12,23}^{max} = \frac{\left(P_{12}^{max} - P_{12}^{0}\right)}{PTDF_{12,23}} = \frac{|-600-138|}{0.3077} = 2398MW$$
....(4.28)

$$P_{13,23}^{max} = \frac{\left(P_{13}^{max} - P_{13}^{0}\right)}{PTDF_{13,23}} = \frac{|200-338|}{0.3077} = 448MW$$
....(4.29)

$$P_{23,23}^{max} = \frac{\left(P_{23}^{max} - P_{23}^{0}\right)}{PTDF_{23,23}} = \frac{|600-462|}{0.6923} = 199.3MW$$
....(4.30)

As per equation 4.13, ATC between buses 2 and 3 is 199.3 MW.

ATC Calculation Using PTDF and LODF

The calculation of ATC should also take into account the effect of line contingency. In other words, it should indicate the available transfer capacity after considering the changes in line flows due to the largest line contingency. For this, the concept of Line Outage Distribution Factor (LODF) is introduced and used for ATC calculation.

Line Outage Distribution Factor (LODF):

When an outage occurs, the power flowing over the outaged line is redistributed onto the remaining lines in the system. The LODF is the measure of this redistribution. $LODF_{lm,rs}$ is the fraction of the power flowing on the line rs before it is outaged, which now flows over a line from l to m.

$$\Delta P_{lm,rs} = LODF_{lm,rs} P_{rs}$$

....(4.31)

The LODF is given by

$$LODF_{lm,rs} = \frac{N_{rs} \cdot x_{rs}}{N_{lm} \cdot x_{lm}} \frac{\left(X_{lr} - X_{ls} - X_{mr} + X_{ms}\right)}{N_{rs} \cdot x_{rs} - \left(X_{rr} + X_{ss} - 2X_{rs}\right)}$$

....(4.32)

Where,

x_{lm} reactance of line connecting bus l and m

X_{lr} entry in lth row and rth column of bus reactance matrix X

N_{lm} number of circuits connecting bus l and bus m

Consider a transaction from bus i to bus j and the outage of a line from bus r to bus s (line rs). The change in flow on line rs due to the transaction is

$$\Delta P_{rs}^{new} = PTDF_{rs,ij} P_{ij}$$

....(4.33)

When line rs is outaged, part of the flow appears on line lm. s resulting from both the outage of the line rs and a new transaction from bus i to bus j is given by

$$\Delta P_{lm,rs} = \left(PTDF_{lm,ij} + LODF_{lm,rs} PTDF_{rs,ij}\right) P_{ij}$$

....(4.34)

The maximum contingency limited transfer from bus i to bus j, limited by line lm, with the outage of line rs, is given by

$$\Delta P_{ij,lm,rs}^{max} \pounds \frac{P_{lm}^{max} - P_{lm}^{0}}{PTDF_{lm,ij} + LODF_{lm,rs} PTDF_{rs,ij}}$$

....(4.35)

Where, P_{lm}^{max} indicates the post contingency flow limit on line lm.

To find the contingency limited ATC, all possible combinations of outaged lines and limiting lines must be checked, as well as steady state transfer limit.

$$ATC_{ij,rs} = \min\left(\min P_{ij,lm}^{max}, \min P_{ij,lm,rs}^{max}\right) \; \forall lm$$

....(4.36)

Using the above equations, any proposed transaction for the specific hour may be checked by calculating the ATC. If it is greater than the amount of proposed transaction, the transaction is allowed. If not, the transaction must be rejected or limited to the ATC.

Calculation of PTDF Using AC Model

In the previous section we have seen PTDF calculation using DC power flow model. But this involves many assumptions which lead to inaccurate results. More accurate PTDFs can be calculated using AC power flow model. Line power flows are simply function of the voltages and angles at its terminal buses. So PTDF is a function of these voltage and angle sensitivities.

Consider an n node system with nodes1,......,g as PV nodes (generator buses) and g+1,...,n as the PQ nodes (load buses). Bus 1 is taken as slack bus. A transaction is defined by a set of four parameters (t, i, j, Pt) where t is the transaction number, i and j are the source and sink nodes and Pt is the MWs transacted. The change in flow of an arbitrary line lm can be evaluated by sensitivity analysis as follows.

$$\Delta P_{lm} = \begin{bmatrix} \frac{\partial P_{lm}}{\partial \delta_2} & \cdots & \frac{\partial P_{lm}}{\partial \delta_n} & \frac{\partial P_{lm}}{\partial V_{g+1}} & \cdots & \frac{\partial P_{lm}}{\partial V_n} \end{bmatrix} \begin{bmatrix} \Delta\delta_2 \\ \vdots \\ \Delta\delta_n \\ \Delta|V_{g+1}| \\ \vdots \\ \Delta|V_n| \end{bmatrix}$$

....(4.37)

From the converged base case Load Flow solution we have,

$$\begin{bmatrix} \Delta\delta_2 \\ M \\ \Delta\delta_n \\ \Delta|V_{g+1}| \\ M \\ \Delta|V_n| \end{bmatrix} = J^{-1} \begin{bmatrix} \Delta P_2 \\ M \\ \Delta P_n \\ \Delta|Q_{g+1}| \\ M \\ \Delta|Q_n| \end{bmatrix} \qquad \text{.......(4.38)}$$

where J is load flow Jacobian. For a MW power transaction number t,

$$\Delta P_i = +P_t \qquad \text{.......(4.39)}$$

$$\Delta P_j = -P_t \qquad \text{.......(4.40)}$$

$$\Delta P_k = 0 \qquad \text{.......(4.41)}$$

$$\Delta Q_k = 0 \qquad \text{.......(4.42)}$$

where, $(k = l, \ldots, n, k \neq i, j)$. Substituting 4.6-4.9 in 4.5 and then in 4.4,

$$\Delta P_{lm} = \begin{bmatrix} \frac{\partial P_{lm}}{\partial \delta_2} & \cdots & \frac{\partial P_{lm}}{\partial \delta_n} & \frac{\partial P_{lm}}{\partial V_{g+1}} & \cdots & \frac{\partial P_{lm}}{\partial V_n} \end{bmatrix} \begin{bmatrix} J^{-1} \end{bmatrix} \begin{bmatrix} 0 \\ \vdots \\ +P_t \\ 0 \\ \vdots \\ -P_t \\ 0 \end{bmatrix} = d_t P_t \qquad \text{.......(4.43)}$$

2. What is meant by available transfer capability? Describe the methods to calculate TTC and ATC.

Transfer capability of a transmission system is a measure of unutilized capability of the system at a given time and depends on a number of factors such as the system generation dispatch, system load level, load distribution in network, power transfer between areas and the limit imposed on the transmission network due to thermal, voltage and stability considerations. In the contingency, it is computed after the operation of any automatic devices to secure the system constraints but before any post-contingency operator initiated the system adjustments.

ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

ATC can be expressed as:

ATC = TTC – TRM – Existing Transmission Commitments (including CBM)

Transmission Reliability Margin is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Capacity Benefit Margin is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Utilities would have to determine adequately their ATC's to insure that system reliability is maintained while serving a wide range of transmission transactions. ATC between and within areas of the interconnected power system and ATC for critical transmission paths between these areas would be continuously updated and posted changes in scheduled power transfers between the areas.

The ATC principles are stated as follows:

1. ATC calculations recognize time-variant power flow conditions and simultaneous transfers and parallel path flow throughout the transmission network.
2. ATC calculations must recognize the dependency of ATC on the points of power injection, the direction of power transfers and the points of power extraction.
3. ATC calculations must produce commercially viable results and the computed ATC must give a reasonably accurate and dependable indication of transfer capabilities available to the electric power market.

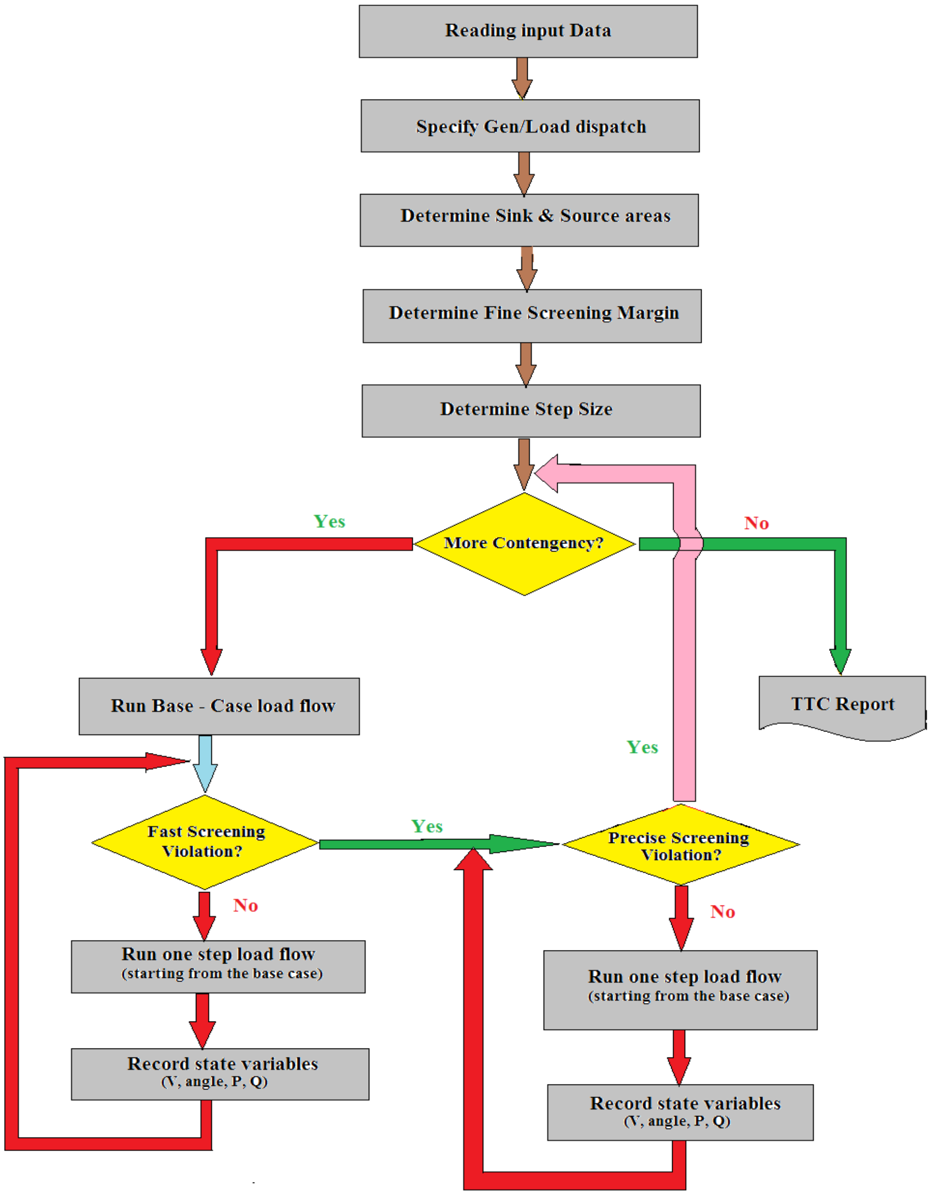
Total Transfer Capability Calculation technique

Tracing load flow technique

Algorithm

1. Load input data file.
2. Specify the TTC calculation method. Either GG method or LG method.
3. Determine the source area and sink area.
4. Specify load / generation dispatching scenario.
5. Specify the initial contingency set (transmission lines and generations).

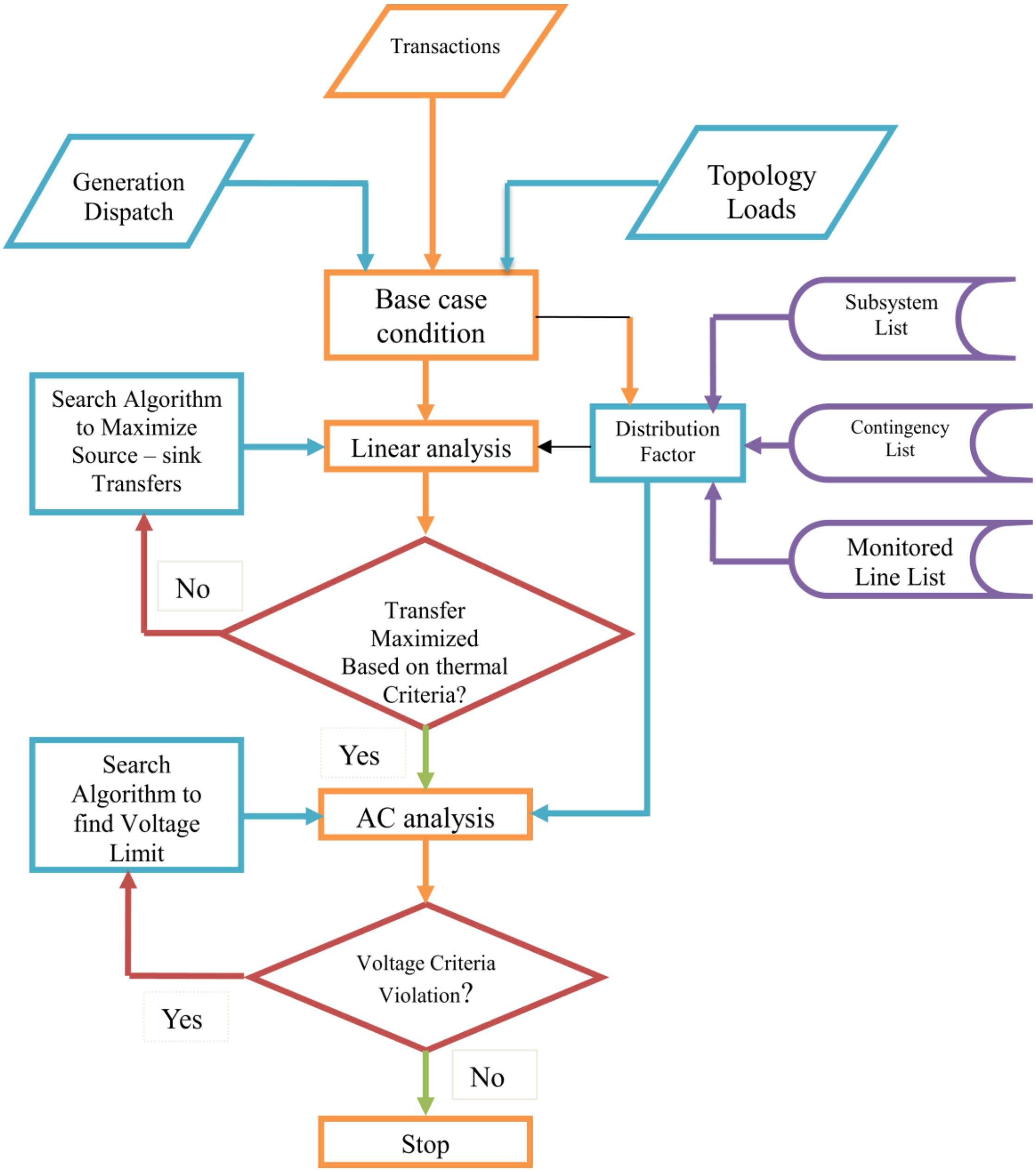
6. Determine a precision level for which the fast TTC calculations will stop and precise calculations will start. This number is a percentage from the transmission line thermal or bus voltage limits.
7. Determine the step size for increasing / decreasing the generation / loads in the sink area. Small steps will lead to increasing in the number of iterations for the precise screening calculations. However, if the system is stressed, a small step size is recommended.
8. Run the base case load – flow under one of the selected contingencies out of the initial contingency set.



9. Start TTC fast screening loop. In each loop step, record the power system state variables (active power, reactive power, bus – voltage, and bus – angle). These variable can be used for further analysis.
10. After finishing the fast TTC calculations, switch to precise calculations. The precise calculations start from the last unconstrained step in the fast screening. The precise screening margin is set equal to the thermal limit or the minimum acceptable voltage.
11. Repeat the fast and the precise screening loop for every contingency.

12. The TLF report contains a TTC values for each contingency. TLF can also report state variable profiles. For example, the most critical voltage bus profiles, the critical phase angle profile across the transmission line.

ATC Calculation using search Algorithm Technique



4. **What is meant by congestion in power system? (may'08)**

Congestion management in a multi-buyer/ multi-seller system is one of the most involved tasks if it has to have a market based solution with economic efficiency. In a vertically integrated utility structure, activities such as generation, transmission and distribution are within direct control of a central agency or a single utility. Generation is dispatched in order to achieve the system least cost operation. Along with this, the optimal dispatch solution using security constrained economic dispatch eliminates the possible occurrence of congestion. This effectively means that generations are dispatched such that the power flow limits on the transmission lines are not exceeded.

One should not expect things to be as simple in a deregulated power environment. In a deregulated environment, every buyer wants to buy power from the cheapest generator available, irrespective of relative geographical location of buyer and seller. As a consequence of the this, the transmission corridors evacuating the power of cheaper generators would get overloaded if all such transactions are approved. Congestion is then said to have occurred when system operator finds that all the transactions cannot be allowed on account of overload on the transmission network. Congestion management is a mechanism to prioritize the transactions and commit to such a schedule which would not overload the network. Despite these measures, congestion can still occur in real time following a forced outage of transmission line. The system operator then handles this situation by means of real time congestion management. Thus, congestion management involves precautionary as well as remedial action on system operator’s part, as follows:

- Allow only that set of transactions which, taken together, keeps the transmission system within limits.
- Even if this care is taken, in real time, the transmission corridors may get overloaded due to unscheduled flows. The system operator has to take some remedial action.

The scope of transmission congestion management in the deregulated environment involves defining a set of rules to ensure control over generators and loads in order to maintain acceptable level of system security and reliability. The rules should ensure market efficiency maximization with short term as well as long term horizons. The robustness of rule set is important as under open market structure a set of players will always be looking for loopholes in the mechanism to exploit it.

In a deregulated structure, the market must be modeled so that the market participants (buyers and sellers of energy) engage freely in transactions and play as per market forces, but in a manner that does not threaten the security of the power system. Thus, irrespective of the market structure in place, congestion management has universally become an important activity of power system operators. Universally, the dual objectives of congestion management schemes have been to minimize the interference of the transmission network in the market for electrical energy and to simultaneously ensure secure operation of the power system.

This chapter is aimed at explaining various congestion management schemes employed under various market structures. The chapter provides classification of congestion management schemes based on the economic efficiency associated with each one of them.

5. **Explain the concept of Congestion management .l (may'08)**

Whenever the physical or operational constraints in a transmission network become active, the system is said to be in a state of congestion. The possible limits that may be hit in case of congestion are: line thermal limits, transformer emergency ratings, bus voltage limits, transient or oscillatory stability, etc. These limits constrain the amount of electric power that can be transmitted between two locations through a transmission network. Flows should not be allowed to increase to levels where a contingency would cause the network to collapse because of voltage instability, etc.

The peculiar characteristics associated with electrical power prevent its direct comparison with other marketable commodities. First, electrical energy can not be stored in large chunks. In other words, the demand of electric power has to be satisfied on a real time basis. Due to other peculiarities, the flexibility of directly routing this commodity through a desired path is very limited. The flow of electric current obeys laws of physics rather than the wish of traders or operators. Thus, the system operator has to decide upon such a pattern of injections and take-offs, that no constraint is violated.

Inter-zonal Congestion Management

The concept of inter-zonal/ intra-zonal congestion management can be explained with the help of a simple illustrative example. Figure 4.3 shows a simple 3 bus, 2 zone system in a certain hour, with two scheduling coordinators (QSEs).

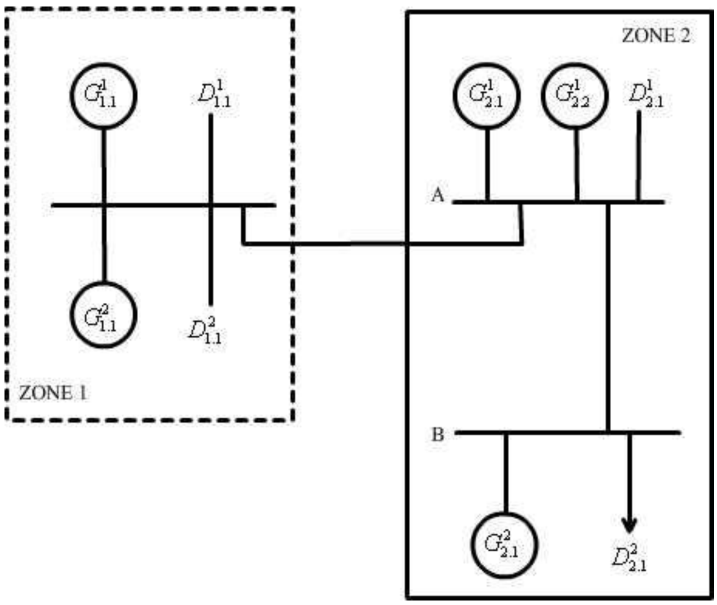


Figure 4.3: Two zone example

Variables $G^{i}_{k,j}$ refers to jth generator of ith QSE in zone k. Similarly, variables $D^{i}_{k,j}$ refers to jth load of ith QSE in zone k. The preferred initial schedules and incremental
decremental bids of the QSE s are given in Table 4.6.

Suppose the line connecting zone 1 and 2 has power carrying capacity of 500 MW. Since the total generation in zone 1 as per preferred schedule is 900 MW and load in zone being 300 MW, 600 MW will flow on line connecting zones 1 and 2, resulting in a 100 MW violation. This is the case of inter-zonal transmission congestion management. The ISO's congestion relief protocol requires that the balanced schedule of each QSE be preserved (balanced portfolio). In other words, an increase (or decrease) in a certain QSE's portfolio is compensated by corresponding decrease (or increase) from the same QSE.

Thus, decrease in generation of QSE1 in zone 1 with corresponding increase in generation of QSE 1 in zone 2 (to balance the portfolio), the cost incurred would be (2000-1000=1000 INR/MWh). Thus, QSE 1 places an implicit bid of INR 1000/MWh. Similarly, QSE 2 places an implicit bid of INR 2000/MWh. Since, bid of QSE 2 is higher than QSE 1, scheduled flow of 300 MW of QSE 2 will not be altered, while scheduled flow of QSE 1 will be decreased until the line limit is not violated. Thus, scheduled flow of QSE 1 will be made 200 MW by making generation of equal to 400 MW and that of equal to 100 MW. Due to requirement of balancing the portfolio, following conditions are satisfied:

$$G^{1}_{1,1} + G^{1}_{2,1} + G^{1}_{2,2} = D^{1}_{1,1} + D^{1}_{2,1} \quad \text{...(4.75)}$$

$$G^{2}_{1,1} + G^{2}_{2,1} = D^{2}_{1,1} + D^{2}_{2,1} \quad \text{...(4.76)}$$

QSE	Variable	Pref. Schedule	Inc/Dec Bid
QSE1	$G^{1}_{1,1}$	500	1000
	$G^{1}_{2,1}$	0	2000
	$G^{1}_{2,2}$	100	4000
	$D^{1}_{1,1}$	200	-
	$D^{1}_{2,1}$	400	-
QSE2	$G^{2}_{1,1}$	400	3000

	$G_{2,1}^{2}$	0	5000
	$D_{1,1}^{2}$	100	-
	$D_{2,1}^{2}$	300	-

Table 4.6: Preferred initial schedules and Inc/Dec bids

Congestion Charges: Zone 2 LMP is set by and it is equal to INR 2000/MWh. Similarly, Zone 1 LMP is set by and equals INR 1000/MWh. Congestion charges for QSE 1 are calculated as follows:

$$(400\times 2000 - 400\times 1000) + (-200\times 2000 + 200\times 1000) = 20\times 10^{4} \text{ ₹}$$

....(4.77)

Similarly, congestion charges for SC2 are calculated as follows:

$$(300\times 2000 - 400\times 1000) + (-0\times 2000 + 100\times 1000) = 30\times 10^{4} \text{ ₹}$$

....(4.78)

The ISO thus receives INR as total congestion charges and then allocates the money to transmission right holders on that path.

Intra-zonal Congestion Management

Figure 4.4 shows zone 2 with nodal injections and line flows after inter zonal congestion relief.

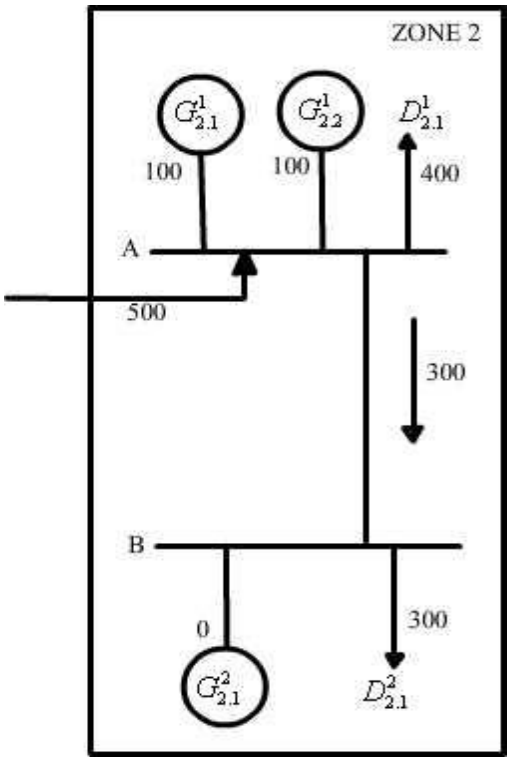


Figure 4.4: Intra-zonal congestion management

It is seen that after the phase of inter zonal congestion management, the flow on line connecting nodes A and B is 300 MW, whereas, its limit is 250 MW. In order to relieve this intra zonal congestion, the generator with highest decremental bid on bus A is called for decreasing its generation. In this particular example, has the highest decremental bid (INR 4000/MWh). Hence, its output is reduced by 50 MW, while generator output will be increased by 50 MW, leading to flow on line AB as 250 MW.

Intra zonal congestion settlement:

Generator $G_{2,2}^{1}$ belonging to QSE 1 decreased its output by 50 MW. Thus, payment by QSE 1 to ISO is

$$50 \times 4000 = 20 \times 10^4 \text{ ₹}$$ ....(4.79)

Similarly, generator $G_{2,1}^{2}$ belonging to QSE 2 increased its output by 50 MW. Thus, payment by ISO to QSE 2 is given by

$$50 \times 5000 = 25 \times 10^4 \text{ ₹}$$ ....(4.80)

Thus, total balance with ISO is INR. This will be recovered from QSE s as a zonal uplift based on their load in zone 2. If ISO's balance for intra zonal congestion management is positive, then this uplift is credited to QSE s based on their load in that zone. In case of negative balance, the QSE s are debited. In the above case, QSE s will be charged as follows:

QSE 1 pays $\left[5 \times \frac{400}{700}\right] \times 10^4 = 2.8571 \times 10^4 \text{ ₹}$ ....(4.81)

QSE 2 pays $\left[5 \times \frac{300}{700}\right] \times 10^4 = 2.1429 \times 10^4 \text{ ₹}$ ....(4.82)

6. Explain Importance of congestion management in the deregulated environment

If the network power carrying capacity is infinite and if there are ample resources to keep the system variables within limits, the most efficient generation dispatch will correspond to the least cost operation. Kirchoff's laws combined with the magnitude and location of the generations and loads, the line impedances and the network topology determine the flows in each line. In real life, however, the power carrying capacity of a line is limited by various limits as explained earlier. These power system security constraints may therefore necessitate a change in the generator schedules away from the most efficient dispatch. In the traditional vertically integrated utility environment, the generation patterns are fairly stable. From a short term perspective, the system operator may have to deviate from the efficient dispatch in order to keep line flows within limits. However, the financial implications of such re-dispatch does not surface because the monopolist can easily socialize these costs amongst the various participants, which in turn, are under his direct control. From planning perspective also, a definite approach can be adopted for network augmentation.

However, in deregulated structures, with generating companies competing in an open transmission access environment, the generation / flow patterns can change drastically over small time periods with the market forces. In such situations, it becomes necessary to have a congestion management scheme in place to ensure that the system stays secure. However, being a competitive environment, the re-dispatch will have direct financial implications affecting most of the market players, creating a set of winners and losers. Moreover, the congestion bottlenecks would encourage some strategic players to exploit the situation. The effects that congestion is likely to cause are discussed next.

Effects of Congestion

The network congestion essentially leads to out-of-merit dispatch. The main results of these can be stated as follows:

- Market Inefficiency: Market efficiency, in the short term, refers to a market outcome that maximizes the sum of the producer surplus and consumer surplus, which is generally known as social welfare. With respect to generation, market efficiency will result when the most cost-effective generation resources are used to serve the load. The difference in social welfare between a perfect market and a real market is a measure of the efficiency of the real market. The effect of transmission congestion is to create market inefficiency.
- Market Power: If the generator can successfully increase its profits by strategic bidding or by any means other than lowering its costs, it is said to have market power. Imagine a two area system with cheaper generation in area 1 and relatively costlier generation in area 2. Buyers in both the areas would prefer the generation in area 1 and eventually the tie-lines between the two areas would start operating at full capacity such that no further power transfer from area 1 to 2 is possible. The sellers in area 2 are then said to possess market power. By exercising market power, these sellers can charge higher price to buyers if the loads are inelastic. Thus, congestion may lead to market power which ultimately results in market inefficiency.

In multi-seller / multi-buyer environment, the operator has to look after some additional issues which crop up due to congestion. For example, in a centralized dispatch structure, the system operator changes schedules of generators by raising generation of some while decreasing that of others. The operator compensates the parties who were asked to generate more by paying them for their additional power production and giving lost opportunity payments to parties who were ordered to step down. The operator has to share additional workload of commercial settlements arising due to network constraints which, otherwise, would have been absent.

One important thing to be noted is that creation of market inefficiency arising due to congestion in a perfectly competitive market acts as an economic signal for network reinforcement. The market design should be such that the players are made to take a clue from these signals so as to reinforce the network, thus mitigating market inefficiency.

6. Explain Price area congestion management.

This is a simplified version of the inter-zonal and intra-zonal congestion management scheme. This method consists of splitting a power exchange into geographical bid areas with limited capacities of exchange. When congestion is predicted, the system operator declares that the system is split into areas at predicted congestion bottlenecks. Spot market bidders must submit separate bids for each price area in which they have generation or load. If no congestion occurs during market settlements, the market will settle at one price, which will be the same as if no price areas existed. If congestion does occur, price areas are separately settled at prices that satisfy transmission constraints. Areas with excess cheaper generation will have lower prices, and areas with excess load - higher prices. Market income from this price difference is paid to the SO and he further uses it for grid enhancement. Bilateral contracts that span price areas must purchase the load’s energy in its price area in order to account for the contribution to congestion and to expose the contract to the financial consequences of congestion.

An advantage about the market splitting method is that on a long-term basis, new gencos may decide to add capacity in deficit zones, attracted by high sale prices, and thus introduce more competition and cause overall prices to decrease. A limitation associated with this type of system is that it can be used only when physical zones are connected in radial fashion. In a meshed system, clear cut boundaries of physical zones can not be established. This type of congestion management system is used in Norway.

Algorithm for Price Area Congestion Management Scheme

Resolving congestion management by market splitting is a step by step process. Algorithm 1 gives a step by step procedure for price area congestion management. The scheme is explained with a simple two bus system shown in Figure 4.5.

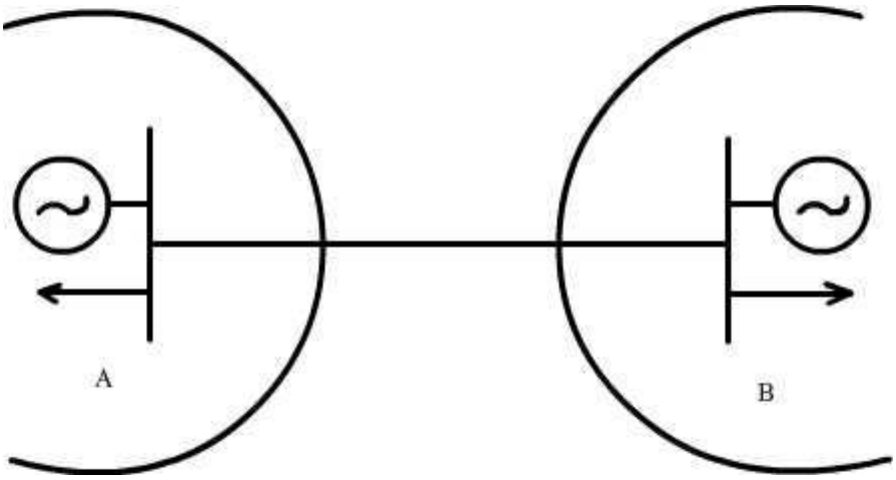


Figure 4.5: Two area system

With no congestion, the market will settle at a single unconstrained market price MPU, and the total generation and load will be equal, i.e.,

$$P_{G_A} + P_{G_B} = P_{D_A} + P_{D_B} \quad \text{...(4.83)}$$

Where,

P_{G_A}, P_{G_B} generation in areas A and B respectively

P_{D_A}, P_{D_B} loads in areas A and B respectively

Since price area A has overall cheaper generation, area A will be net exporter and flow on line AB will be from A to B. If this unconstrained market settlement results in exceeding the transfer limit of line AB, then each zone is treated as a separate area, and the zonal markets are resolved separately. The power balance constraint in zone A is that generation equals area A load plus transfer on line AB. The value of transfer is the maximum transfer limit of line AB. An example of the supply and demand curves for two areas A and B is shown in Figure 4.6.

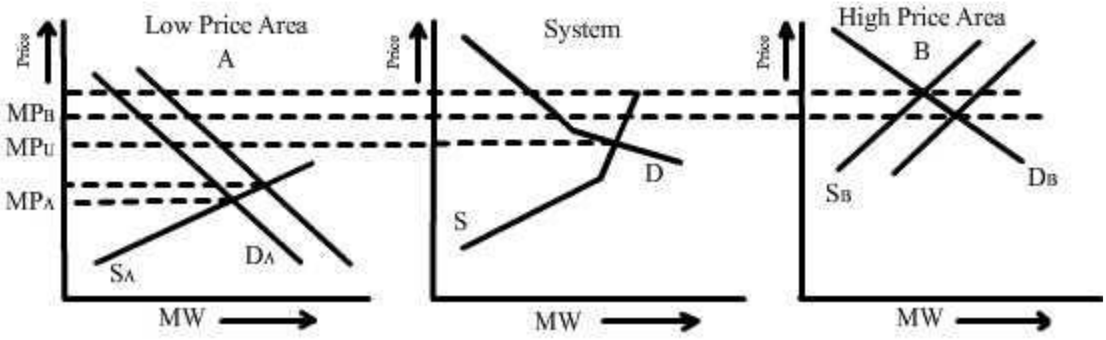


Figure 4.6: Price area settlement for Two zone system

Here, the unconstrained market clearing price is MPU. The exchange capacity is included in the area price calculation by moving the supply curve in area B and the demand curve in area A, as indicated by the dotted curves. Now,

$$P_{G_A} = P_{D_A} + P_{AB}^{max} \qquad \text{...(4.84)}$$

Similarly,

$$P_{D_B} = P_{G_B} + P_{AB}^{max} \qquad \text{...(4.85)}$$

Individual settlements for each market is done once again. This arrangement ensures that PAB is restricted to . It can be seen from the Figure 5.6 that the area A price (MPA) is lower than unconstrained market clearing price (MPU), where as the price of area B (MPB) is higher than (MPU). The difference between the respective area prices and the system price is called the network rent and is given as:

$$Network\_Rent = P_{AB}^{max}\left(MP_B - MP_A\right)$$

....(4.86)

Algorithm for Price Area Congestion Management

1. Solve unconstrained market clearing process. That means, the market clearing for the whole system is done using only bid data and without network constraints.
2. A power flow simulation is carried out using nodal injection data obtained after step 1.
3. Check whether any of the line limit is getting violated.
4. Depending on the congestion bottleneck, form the price areas across the congested corridor.
5. Do separate market settlements in each price area. Thus, two separate market clearing prices are formed.
6. Adjust demand curve in cheap price area by giving it a lateral shift to the right. Similarly adjust

supply curve in high price area by giving it a lateral shift to the right. The amount of lateral shift is equal to the line flow limit of congested bottleneck.

7. After making adjustments given in step 6 and doing market clearing for individual areas, it is ensured that transmission congestion is relieved. This leads to two different prices in two price areas. The settlements are done using respective area prices.

Illustrative Example

Consider a two area system as shown in Figure 4.5. Suppose the capacity of line between the system A and B is 100MW. The Power exchange receives buy and sell bids from both areas A and B. These bids present power as a function of price. These are represented as:

$$P_{D_i}(\text{price}) = a_i \times \text{price} - b_i \quad \text{..........}(4.87)$$

$$P_{G_i}(\text{price}) = c_i \times \text{price} - d_i \quad \text{..........}(4.88)$$

The bid constants are given in Table 4.7.

Area	sell Bid		Buy Bid	
	c	d	a	b
A	15	120	-4	-350
B	8	160	-6	-525

Table 4.7: Bid Data

Step 1: Unconstrained market settlement is done initially. This gives a market price of 35 INR/MWh. The powers in each area are shown in the Table 4.8:

Area	PG	PD
A	405	210
B	120	315

Table 4.8: Results of unconstrained market settlement

Step 2: Calculate the power flow on line AB. In this example,

$$P_{AB} = \left(P_{G_A} - P_{D_A}\right) = -\left(P_{G_B} - P_{D_B}\right) = 195MW$$

....(4.89)

Step 3: The results of step 1 are compared with the line flow limits to see if congestion is occurring on any of the corridors. In this case, the flow on line connecting areas A and B is 195 MW as against its capacity of 100 MW.

Step 4: Separate the market into two price areas: area A and area B.

Step 5: Find out market clearing prices of individual price areas, using load and generation bid data of respective areas. The outcome of this is presented in Table 4.9.

Area	**PG**	**PD**	**Area Price**
A	250	250	24.73
B	231	231	48.95

Table 4.9: Results of individual market settlement

Step 6: Using the principle of market-splitting, each area is now dispatched separately and by including the line capacity constraint. The cumulative load curve in area A and cumulative supply curve in area B are adjusted such that flow over a line connecting areas A and B is restricted to 100 MW. This adjustment renders following functions for individual market settlements:

$$P_{G_A}\left(\text{price}\right) + 100 = c \times \text{price} - d$$

....(4.90)

$$P_{D_B}\left(\text{price}\right) + 100 = a \times \text{price} - b$$

....(4.91)

Step 7: The results of final dispatch are given in Table 4.10.

Area	PG	PG	PAB	Area Price
A	330	230	100 (net export)	30.0
B	174.3	274.3	-100 (net export)	41.78

Table 4.10: Results of constrained market settlement

In this case, after making settlements, there is some money left with the power exchange. It is equal to differences of area prices times the flow on tie line connecting two areas.

Network_Rent $= (41.78 - 30.0) \times 100 = 1178$ ₹

....(4.92)

It is apportioned to the TSOs involved for grid capacity enhancement. Bilateral contracts that span price areas must sell the energy in the supply area and purchase energy in the load area to account for the contribution to congestion, and to expose the contracts to the financial consequences of congestion. It is the only instance of mandatory spot market participation.

PART-A

1. **What is Total Transfer Capability (TTC)?**

   It is defined as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of the specific set of defined pre and post contingency system conditions.

2. **What is Transmission Reliability Margin (TRM)?**

   It is defined as the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

3. **What is Capacity Benefit Margin (CBM)?**

It is defined as the amount of transmission transfer capability reserved by load serving entities to ensure that the interconnected systems do meet generation reliability requirements.

4. **What is congestion management?**

   Whenever the physical or operational constraints in a transmission network become active, the system is said to be in a state of congestion. The possible limits that may be hit in case of congestion are: line thermal limits, transformer emergency ratings, bus voltage limits, transient or oscillatory stability, etc. These limits constrain the amount of electric power that can be transmitted between two locations through a transmission network. Flows should not be allowed to increase to levels where a contingency would cause the network to collapse because of voltage instability, etc.

5. **Distinguish between static and dynamic ATC.**
6. **What is the concept of congestion management?**

   Whenever the physical or operational constraints in a transmission network become active, the system is said to be in a state of congestion. The possible limits that may be hit in case of congestion are: line thermal limits, transformer emergency ratings, bus voltage limits, transient or oscillatory stability, etc. These limits constrain the amount of electric power that can be transmitted between two locations through a transmission network. Flows should not be allowed to increase to levels where a contingency would cause the network to collapse because of voltage instability, etc.

DEPARTMENT OF ELECTRICAL & ELECTRONICS ENGINEERING

Subject Name: **POWER SYSTEM RESTRUCTURING AND DEREGULATION**

Subject Code: **EE E89**

Prepared by:

1. Mrs.S.Punitha , AP/EEE
2. Mr.V.Malarselvam, AP/EEE

Verified by: *Approved by:*

UNIT –III TRANSMISSION NETWORKS AND SYSTEM SECURITY SERVICES

Transmission expansion in the new environment-Introduction-Role of transmission planning-Physical Transmission Rights-Limitations-Flow gate-Financial transmission right losses-Managing transmission risks-Hedging- investment

Ancillary Services-Introduction-Describing needs-Compulsory and demand-side provision-Buying and selling ancillary services-Standards.

(2 MARKS)

1. **What is the need of transmission expansion in the deregulated environment?(April 2015)(Nov 2013)**

   In the dependent phase the TP functions as a part of vertically integrated utility.

   In the passive phase the TP stands alone and oversees overall market activities. The market participants are required to submit their intended use of the system to the TP and based on the formation the TP allocates transmission capacities following the strict rules set by regulators. The TP assumes no financial responsibilities and has minimal interactions with market participants.

2. **List the various types of ancillary services(May 2007)**

A large number of activities on the interconnected grid can be termed as ancillary services. The North American Electric Reliability Council (NREC) along with Electric Power Research Institute (EPRI) has identified 12 functions as ancillary services. These are:

1. Regulation:.
2. Energy Imbalance:
3. Operating Reserve (Spinning):
4. Operating Reserve (Supplemental):
5. Backup Supply:
6. System Control:
7. Dynamic Scheduling:
8. Reactive Power and Voltage Control Support:
9. Real Power Transmission Losses
10. Network Stability Services from Generation Sources:
11. System Black Start Capability

3. **Define the term ancillary service.**

   The term ancillary services generally refers to power system services other than provision of energy. Specifically, ancillary services are those functions performed by the equipment and people that generate, control, transmit and distribute electricity to support the basic task of transmission.

4. **What is operating cost?**

   Operating costs include transmission losses, costs incurred by generation re-dispatch due to operating constraints such as transmission and bus voltage limits, costs incurred in the provision of ancillary services and management and maintenance expenses.

5. **What does system expansion cost include?**

   System expansion costs include investment to accommodate new users and the extremely important issue of long-term transmission expansion in developing countries.

6. **Briefly describe transmission pricing?**

   Transmission pricing is one of the most complicated issues in restructuring electricity supply because off the physical laws that govern power flow in the transmission network, and the need to balance supply and demand at all times. Since generators and customers are all connected to the same network, actions by one participant can have significant consequences on others making it difficult to investigate the cost each participant is responsible for. In addition to operating costs, embedded costs and financing of future expansion should be reflected in the tariff structure.

7. **What does system expansion cost include?**

   System expansion cost includes investment to accommodate new users and the extremely important issue of long-term transmission expansion in developing countries.

8. **List out the limitations of physical transmission rights.(April 2015)**

   The allocation of physical transmission rights and FTRs — options in parallel at the same bidding zone border are not allowed. The allocation of physical transmission rights and FTRs — obligations in parallel at the same bidding zone border is not allowed

Define hedging.(April 2015)(April/May 2014)

Why pricing transmission services are considered to be a difficult task?)(April/May 2014)

(11 MARKS)

1. Explain the buying and selling ancillary services with standards (April 2015)

Though as good as 40 ancillary services can be listed, when it comes to classification of market models based on ancillary services procurement, they essentially refer to the capacity of generators to provide reserve. The reserves are not a separate service from energy, they are options to buy energy if required. They should be priced as options to call energy in the spot market. However, complicating factor is that the same generating unit can provide energy in the spot market, as well as can act as a reserve. Hence, the system operator's dilemma is about how much of it should be scheduled in the spot market and how much should be kept idle as a reserve.

In the integrated or centralized markets, depending on various technical criteria, the system operator does a joint optimization of energy and reserve market so that optimum scheduling is done with minimum cost as well as appropriate amount is kept for reserve in the optimal fashion. More details on this issue are provided in the module on ancillary services management.

Decentralized Model

The decentralized and integrated models are most clearly distinguished by the different roles of forward/bilateral contracts in the procedures used to schedule and dispatch generation. While the integrated model treats the contracts essentially as financial agreements, and dispatches generators to minimize overall costs, the decentralized model requires the system operator to schedule the system explicitly using the contracts. Thus, transaction is treated as a basic unit to be accommodated in real time system operations.

In all trading models, market participants can make and trade contracts in diverse markets separate from the system operator. The contracts could be one-to-one contracts or obtained through an organized trade. At some predetermined moment prior to real time operations, however, the system operator has to take over to deliver the contracts. The system operator is not intended to facilitate a spot market - he simply schedules trades that have been arranged elsewhere. While transferring transactions to the system operator for scheduling, the condition that the amount bought should be equal to sold should be satisfied. Each seller must have a buyer and each buyer a seller. The aim of decentralized model is to leave as much of the trading as possible to the traders, whereas, in the integrated model, on the day ahead and in real time, the system operator makes the trades by following instructions incorporated in the traders' bids.

The schematic of decentralized dispatch model is presented in Figure 3.14. As shown, the energy market is not an integral part of system operator's activity and essentially depends on an external activity exclusive from the system operator.

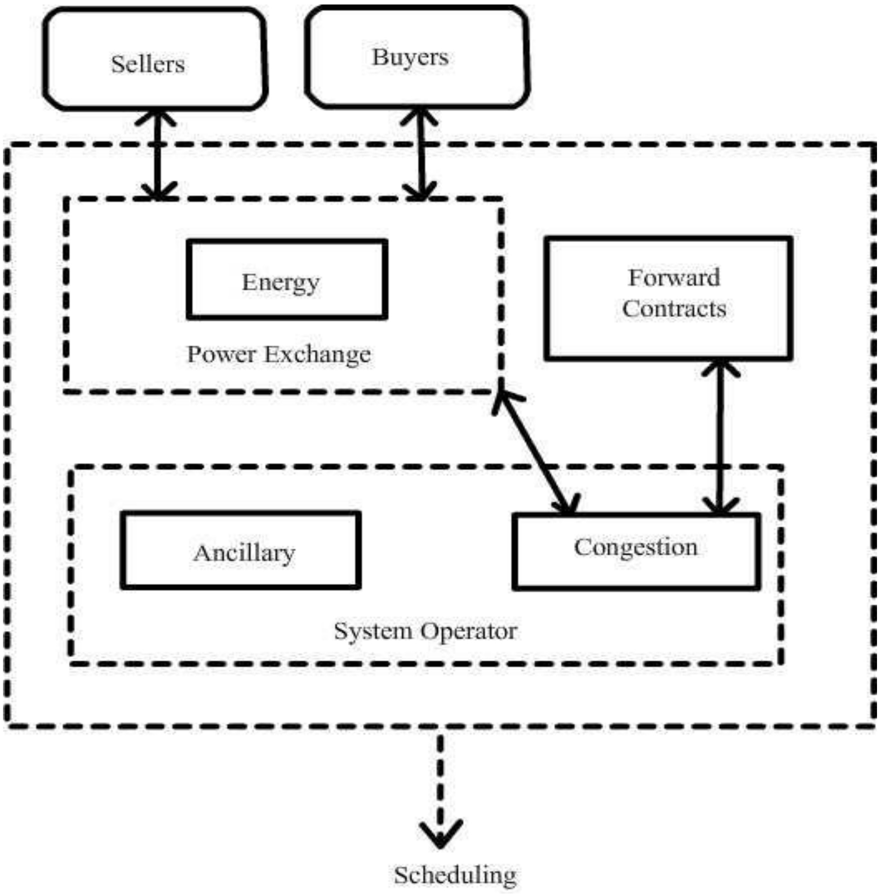


Figure: De-centralized Dispatch

Treatment of Imbalances

The participants of various forward trades wish to balance their positions near real time. This is generally accomplished through a spot market. This provides a common clearing price for imbalances, which is competitive in nature. If a decentralized system has market based imbalance prices, then that price becomes the price at which the system operator will buy or sell energy. The market based price of imbalances provides a reference price for forward contracts. When participants sign contracts, the contract prices are directly compared with the expected imbalances prices as imbalance provides direct substitute for contract energy. The spot market for the imbalance energy is generally run by a power exchange, where the participants submit simple price-quantity bids rather than complex bids.

2. **Explain how the ancillary services procuring important considerations in the new environment of power system(April/May 2012)**

Most of the issues and corresponding debates in deregulated power industry pertain to the socio-economical aspects of the system and the welfare of the society at large. However, the power system infrastructure and the physical laws that govern its utilization continue to be the same, be it vertically integrated utility or the restructured industry. Similarly, the activities of the system operator pertaining to operation and control of the system existed during vertically integrated era and continue to exist in the restructured era. These activities basically stem from the responsibility of the system operator to keep the system in synchronism and operate it reliably. In the restructured environment, these activities are typically known as ancillary services .

Provision of ancillary services under the deregulated environment is not as straight forward as it is described in the vertically integrated structure. Though many reasons can be figured out, the main reason is that the entities providing ancillary services may not be under direct control of the system operator. This issue is highlighted with following two examples. The generators in the competitive market are scheduled as per the bids provided by them to the market. A power system that has generation just enough to support the overall load and losses is still a vulnerable system. The system should have provision for additional generation during contingencies like generator outages. Total capacity of some generating units can be partly dispatched for energy and partly kept ready for reserve. For a particular privately owned generating unit with fast ramp rate, the system operator is likely to schedule most of its capacity as a reserve. The generator, however, may not agree to this unless and until some compensation is provided to it for maintaining its capacity as a reserve. Thus, the development of compensation mechanism for this generator, as well as the cost allocation to customers in an optimal fashion, poses a challenging problem in the restructured environment.

Imagine another situation where, a particular generator is operating on the boundary of its capability curve. An action demanded by the system operator to increase the reactive power injection for this generator requires decrease in real power injection. This action, though essential from the system security perspective, is against the market decision and again, the generator may not agree to do so without proper compensation. Both these situations do not create much problem in the vertically integrated structure because, under that regime, the generating units are directly under the control of system operator, who also is a part of the vertically integrated utility.

A power system would continue to run in synchronism or be stable, unless and until it is perturbed. However, a practical power system having thousands of elements like transmission lines, transformers, switchgear, shunt elements, generators, etc., is certainly prone to disturbances. The system operator has to keep all state variables within the practical limits under normal as well as under contingent situation. Moreover, it has to achieve the global load-generation balance at all times. Thus, even though the power industry has been deregulated, the technical activity of control and operation remains the same. However, the manner in which some of the facilities are procured or provided by the system operator may change, depending upon the type of control.

In the vertically integrated era, whole of the resources required to take corrective control actions are under the control of a single utility. This is not the case under competitive environment. Some of the resources required for control of the system belong to other entities. Thus, they are not mandated to act as per the directives of the system operator, unless and until a commercial agreement exists between them. Thus, these are the services which are required to be purchased by the system operator on commercial terms. As is apparent, the main commodity that is traded in the power market is the electrical power or the electrical energy. However, to make the transactions of power exchange or some other trading platform to be feasible, with security and quality, some supporting services are required, which are nothing but the ancillary services. The word ancillary stems from the fact that they support the main activity of the market, i.e., trading of electrical energy or power. However, since the stability and security is at stake without these services, they certainly have a primary role to play.

Ancillary services are defined as all those activities on the interconnected grid that are necessary to support the transmission of power while maintaining reliable operation and ensuring the required degree of quality and safety. It becomes clear that the ancillary services may include scheduling and dispatch, frequency regulation, voltage control, generation reserves, etc. It is the matter of debate and market design about how to procure these ancillary services. There are some services which can be provided competitively and some services which come under the direct control of the system operator.

3. Write about the types of Ancillary Services.

A large number of activities on the interconnected grid can be termed as ancillary services. During the process of defining the ancillary services, some proposals tried to define 60 different ancillary services! In order to remove this large discrepancy, the North American Electric Reliability Council (NREC) along with Electric Power Research Institute (EPRI) has identified 12 functions as ancillary services. These are:

- .Regulation: The use of generation or load to maintain minute-to-minute generation-load balance within the control area.
- Load Following: This service refers to load-generation balance towards end of a scheduling period.
  - Energy Imbalance: The use of generation to meet the hour-to-hour and daily variations in load.
  - Operating Reserve (Spinning): The provision of unloaded generating capacity that is

synchronized to the grid and can immediately respond to correct for generation-load imbalances, caused by generation and /or transmission outages and that is fully available for several minutes.

- Operating Reserve (Supplemental): The provision of generating capacity and curtailable load to correct for generation-load imbalances, caused by generation and /or transmission outages, and that is fully available for several minutes. However, unlike spinning reserves, supplemental reserve is not required to respond immediately.
- Backup Supply: This service consists of supply guarantee contracted by generators with other generators or with electrical systems, to ensure they are able to supply their consumers in case of scheduled or unscheduled unavailability.
    - System Control: This activity can be compared with the functions of the brain in the human body. System control is all about control area operator functions that schedule generation and transactions and control generation in real time to maintain generation load balance.
    - Dynamic Scheduling: It includes real-time metering, tele-metering along with computer software and hardware to virtually transfer some or all of generator's output or a customer's load from one control area to another.
    - Reactive Power and Voltage Control Support: The injection or absorption of reactive power from generators or capacitors to maintain system voltages within required ranges.
    - Real Power Transmission Losses: This service is necessary to compensate for the difference existing between energy supplied to the network by the generator and the energy taken from the network by the consumer.
    - Network Stability Services from Generation Sources: Maintenance and use of special equipment (e.g., PSS, dynamic braking resistances) to maintain secure transmission system.
    - System Black Start Capability: The ability of generating unit to proceed from a shutdown condition to an operating condition without assistance from the grid and then to energize the grid to help other units start after a blackout occurs.

It should be noted that identification and definition of a particular ancillary service is system dependent. There is no global definition of a particular ancillary service that is applicable in all systems. There can be many other possible definitions or combinations.

4. Explain about classification of Ancillary Services

There can be various ways of classifying the above ancillary services. One common approach would be to identify when and how frequently these services are required by the system operator [23]. Thus, three groups can be formed:

1. Services required for routine operation:

These are the services which the system operator requires quite frequently. Some of these may be required to provide corrective action on minute-to-minute basis. Following services can be grouped under this category:

(a) System control

(b) Reactive power support

(c) Regulation

(d) Load following

(e) Energy imbalance

(f) Real power loss displacement

2. Services required to prevent an outage from becoming a catastrophe:

These services prevent the system from going out of step even if a major event occurs. These do not come into picture on daily basis, or rather; no proactive measures are required to be taken either by the system operator or the service provider on daily basis. Their effectiveness is sensed only under contingent situation. Following services fall under this category:

(a) Spinning reserve

(b)Supplemental reserve

(c)Network stability services

3. Services needed to restore a system after blackout:

Re-energizing the system after complete blackout requires support from certain generating stations, which can pickup generation even in the absence of external electricity support. Such generating units provide the system black start capability. These services are very rarely used.

A closer look at the list of ancillary services reveals that they are either related to:

1. Generation-load balancing issues or
2. The network security related issues.

In further sections, load-generation balancing related services, as well as reactive power support services, under the network security domain are discussed in detail.

Frequency Regulation

Regulation is the use of online generating units that are equipped with control mechanism that can change output quickly to track the moment-to-moment fluctuations in load and unintended fluctuations in generation. In doing so, regulation helps to maintain the system frequency, minimize the differences between actual and scheduled power flows between control areas, and match generation to load within the control area. Figure 6.2 shows the simplified block schematic for frequency regulation.

The frequency regulation consists of two modes of operation, namely, primary regulation and secondary regulation. The primary regulation is basically the governor action with certain droop characteristic, while secondary regulation pertains to Automatic Generation Control (AGC). Figure 6.3 shows the drooping governor characteristics of a generator connected to the system. This droop characteristic is facilitated by a frequency error feedback provided to the governor. The slope of the characteristic determines the change in the unit's output for a given change in frequency. This unit regulation is provided in percentage. For instance, 4% regulation for a unit indicates that a 100% change in unit output requires 4% change in frequency. This corrective action facilitated by governor response is termed as primary regulation.

Figure 6.4 shows drooping characteristics of two units connected to a common load. A change in load in this case, will be shared by both the units, depending on their droop characteristics so as to operate at a unique frequency. At nominal frequency f0, unit 1 and unit 2 outputs are P1 and P2 respectively. In case of a load increase, the units are slowed down and the governors increase the output until the units settle at a new operating frequency f'. Each unit shares additional load in proportion to slope of its droop characteristic, so that their outputs are P_1' and P_2' , respectively.
Thus, the generation increase, taking place within few seconds along with support from frequency dependent loads, arrests any further fall in frequency. The system then (in the absence of proportional and integral control) stabilizes and operates at a new frequency that is slightly less than the nominal frequency. This mechanism is sometimes referred to as Free Governor Mode Operation (FGMO).

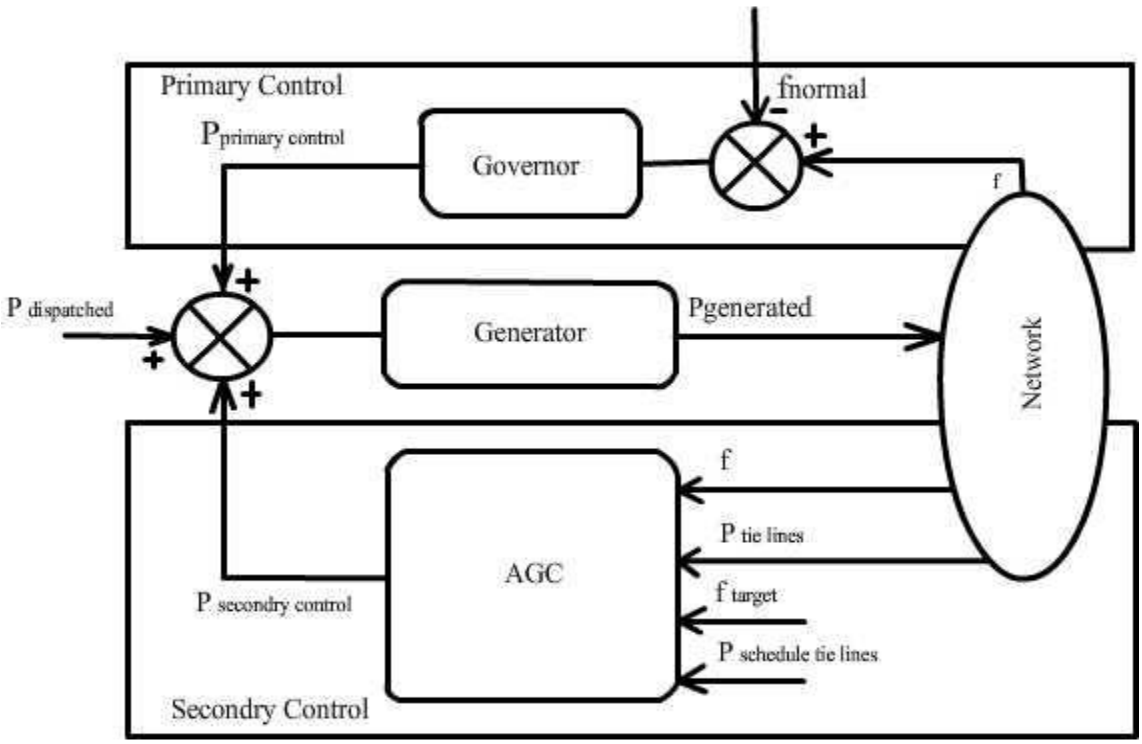


Figure 6.2: Simplified block schematic for frequency regulation

This whole control action causes unscheduled power flows on tie-lines. To restore the system to nominal frequency, the generation set point of some units should be readjusted, based on new generation-load balance. In some instances, this is done through an automatic control action known as Automatic Generation Control (AGC), and is referred to as secondary control. The secondary loop basically aims at bringing the Area Control Error (ACE) to zero so that tie line flows between the control areas are maintained to specified values. In some systems, this is achieved through manual adjustment of governor set point. This control action is sometimes referred to as tertiary regulation.

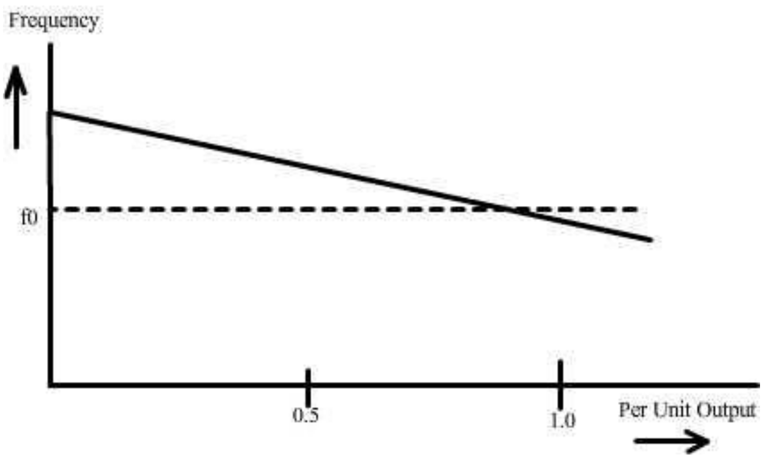


Figure 6.3: Generator droop characteristics

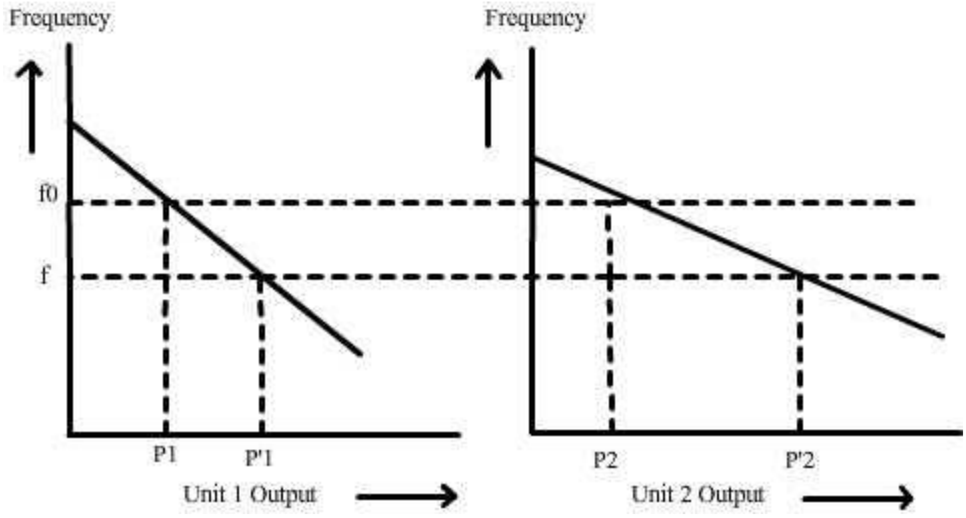


Figure 6.4: Two units sharing same load

Load Following

Load following is the use of online generation equipment to track the intra and inter-hour changes in customer loads. Unlike the minute-to-minute fluctuations, which are generally uncorrelated among customers, the long-term changes in customer loads are generally correlated with each other.

Spinning Reserve Services

Unlike the regulation and load following services, the reserve services are designed to be activated during large power deficits under a contingent situation. The frequency plot associated with the case presented in Figure 6.1 is shown in Figure 6.5. In this, it is assumed that at 7:45 A.M., a big generator is suddenly disconnected. This is the situation when reserve services should come into play. Depending upon the minimum time in which the generation should start providing corrective action, the ancillary services are classified into following two categories:

1. Spinning reserve services
2. Supplemental reserve services

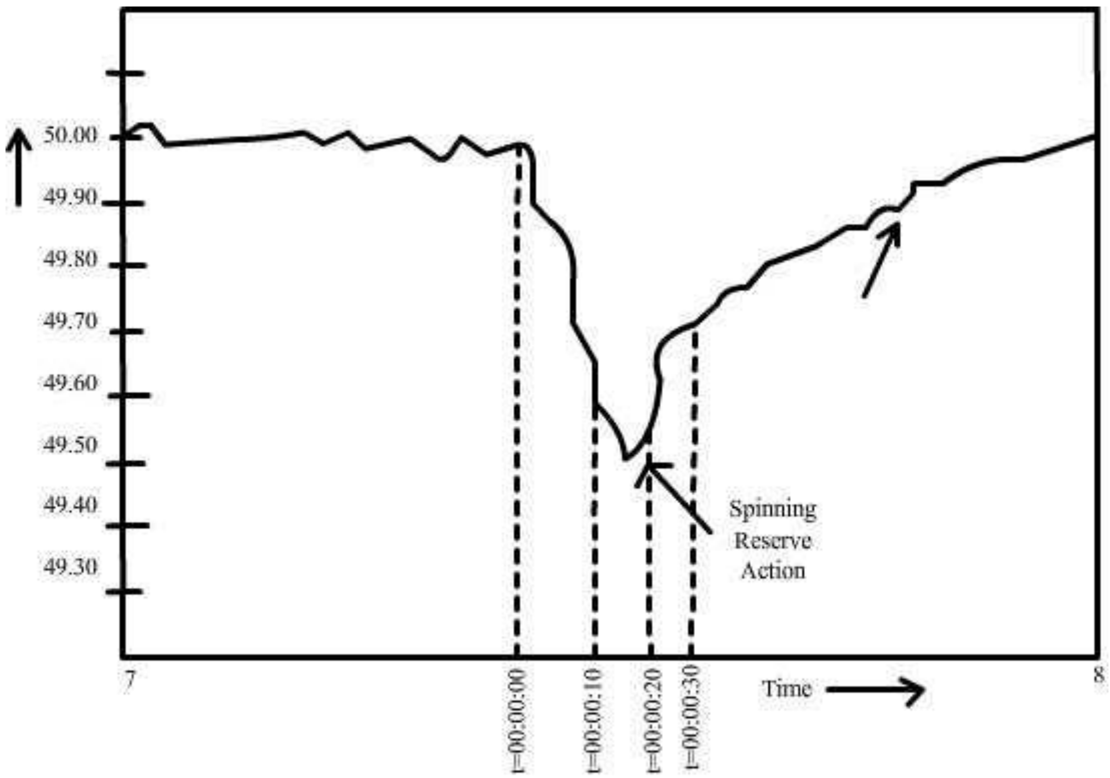


Figure 6.5: Roles of reserve services

The spinning reserves must start responding quickly to the frequency change. These reserves are available in the form of synchronous generators that are synchronized with the grid and generate at a level lower than the maximum rated capacity. This response must be available within 10s and should be sustainable for further 20s. There are various issues of debate related to definition of spinning reserves. There are system specific peculiarities which are reflected in the definition of spinning reserve of that particular system. A discussion on this debate is provided in [24]. Thereby, the authors have provided a general definition of spinning reserves as follows:

The spinning reserve is the unused capacity which can be activated on decision of the system operator and which is provided by devices which are synchronized to the network and able to affect the active power.

Thus, the authors shed light on two important issues: whether spinning reserves are activated manually or are automatic; and whether only generators can provide spinning reserve or demand side can also participate as a spinning reserve? Above generic definition of spinning reserve states that they are activated by system operator manually and in stricter sense, the demand side can also participate as a spinning reserve.

The units providing supplemental services need not start responding immediately. The supplemental reserve services are provided by the generators that have fast start-ups such as gas or oil fired generators or hydro generators. This response must be fully available within 30s of the incidence and must be sustainable for further 30 minutes. As can be seen from Figure 6.5, the spinning reserve succeeds in arresting the frequency drop before it reaches the statutory limit. The supplemental reserve then helps to bring the system frequency closer to nominal value.

While providing supplementary services, the ramp up rate of the generating unit decides its ability to provide the reserve service. However, this is not the only deciding factor. The transmission constraints can limit the ability of a particular unit to act as a reserve provider.

VOLTAGE CONTROL AND REACTIVE POWER SUPPORT SERVICE

System operators use reactive power resources to maintain the voltage at all the buses around the nominal value. Keeping transmission level voltages at nominal value or within a tight range ensures proper voltages at the distribution levels. Another important factor is that the transmission network security is closely associated with the voltage profile. Since the voltage on a bus is strongly coupled with the supply of reactive power, the voltage control service is also called reactive power support service. It is prudent to control the bus voltages by providing for reactive power locally, rather than making it to flow through the grid. There are three major reasons for this. First, the power system equipment is designed to operate within a range of voltages, usually within ± 5% of the nominal voltage. At low voltages, the performance of most of the electrical equipments is poor. For example, induction motors can overheat and get damaged. High voltages not only damage the equipment but lalso shorten their life.

Second, the power transmission capability available from a transmission line design is limited by technological as well as economical constraints. The reactive power consumes transmission and generation capacity. To maximize the amount of real power that can be transferred across a congested transmission interface, reactive power flows must be minimized. Similarly, reactive power production can limit a generator’s real power capability.Third, moving reactive power on the transmission system incurs real power losses. Thus, additional energy must be supplied to replace these losses.

Different Sources of Reactive Power

Reactive power support can be provided by active sources like generators and synchronous condensers, as well as by locally installed passive elements like capacitors or inductors. Power electronics based family of devices called Flexible AC Transmission System (FACTS) can also act as reactive power support devices. Various sources of reactive power support have different characteristics in terms of dynamics and speed of response, ability of voltage changes, capital costs, operating costs and opportunity costs. Their technical as well as economical considerations are discussed next.

Generators

The synchronous generators are very fast reactive support devices. The ability of a generator to provide reactive support depends on its real-power production. Figure 6.6 shows the limits on real and reactive production for a typical generator. This is also called as a capability curve of a generator. Like most electric equipment, generators are limited by their current-carrying capability. Near rated voltage, this capability becomes an MVA limit for the armature of the generator rather than a MW limitation, shown as the armature heating limit in the figure. Production of reactive power involves increasing the magnetic field to raise the generator's terminal voltage. Increasing the magnetic field requires increasing the current in the rotating field winding. This too is current limited, resulting in the field-heating limit shown in the figure. Absorption of reactive power is limited by the magnetic-flux pattern in the stator, which results in excessive heating of the stator-end iron, the core-end heating limit. The synchronizing torque is also reduced when absorbing large amounts of reactive power, which can also limit generator capability to reduce the chance of losing synchronism with the system.

Usually, a synchronous generator is mandated to absorb or produce reactive power in a band bounded by limits R1and R2, shown by dotted lines in Figure 6.6. However, outside this band, it is entitled for opportunity costs if real power output is required to be reduced in order to produce more reactive power. For example, as shown in the figure, if a generator is asked to supply reactive power equal to B2, rather than B1, the operating point of generator changes from current point X to new point Y, forcing reduction in real power output from D1 to D2. More on calculation of loss of opportunity cost is provided in further sections.

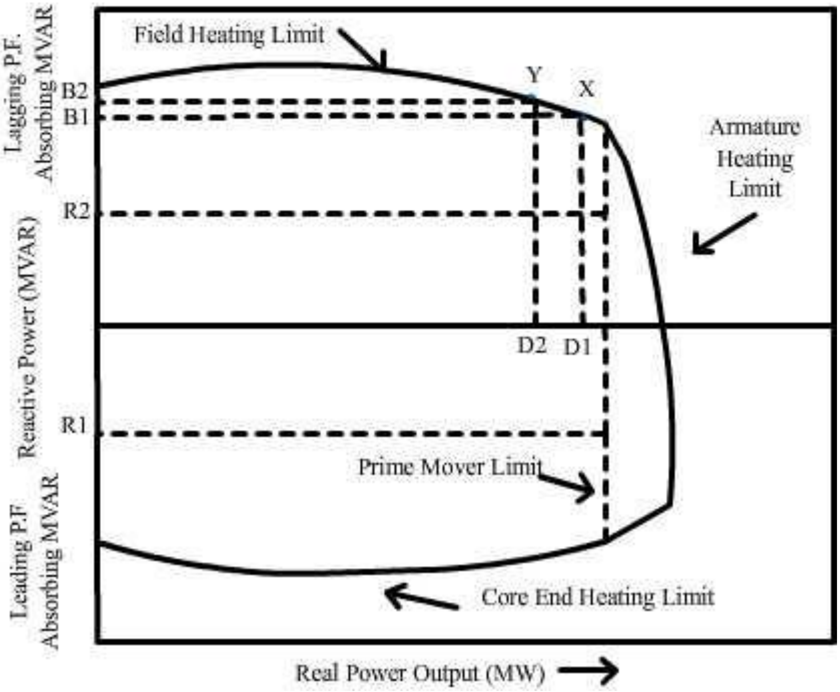


Figure 6.6: Generator Capability Curve

Under the vertically integrated structure, only the capital and operating costs that could be associated with the extra equipment (e.g., parts of the voltage regulator, exciter, stator, and rotor plus the operating costs associated with field losses) required for voltage control were charged to the voltage control function. However, in a deregulated environment, the opportunity costs associated with reduced real power sales when excessive reactive power is required becomes an important component of the total cost of providing voltage control from generators. In [23], it is mentioned that the costs and prices for voltage support will be highly nonlinear with system load. At very high levels of system load, the opportunity cost of voltage support will far exceed the embedded cost.

Synchronous Condensers

Synchronous machines that are designed exclusively to provide reactive support are called synchronous condensers. Synchronous condensers have all of the response speed and controllability advantages of generators without the need to construct the rest of the power plant. As compared to the static alternatives of reactive power support, due to presence of moving parts and system auxiliaries, they require more maintenance. They also consume real power equal to about 3% of the machine's reactive-power rating.

Capacitors and Inductors

Capacitors and inductors are passive devices that generate or absorb reactive power. They accomplish this without significant real-power losses or operating costs. The output of capacitors and inductors is proportional to the square of the voltage. Capacitor banks are composed of individual capacitors. The individual capacitors are connected in series and parallel to obtain the desired capacitor-bank voltage and capacity rating. The capacitor banks are often configured with several steps to provide a limited amount of variable control. Inductors are designed to absorb a specific amount of reactive power at a specific voltage. They can be switched on or off but offer no variable control.

Static VAR Compensators (SVCs)

An SVC combines conventional capacitors and inductors with fast switching capability so as to provide a continuous range of control. The range can be designed to span from absorbing to generating reactive power. Consequently, the controls can be designed to provide very fast and effective reactive support and voltage control. Because SVCs use capacitors, they suffer from the degradation in reactive capability as voltage drops.

Static Synchronous Compensators (STATCOMs)

The STATCOM is a solid-state shunt device that generates or absorbs reactive power and is one member of a family of (FACTS) devices. The STATCOM shows similar performance as that of SVC, when compared on the basis of response speed, control capabilities, and the use of power electronics. However, the basic difference is that the STATCOM uses power electronics to synthesize the reactive power output, without employing capacitors and inductors. The STATCOM ensures very fast and efficient voltage control by virtue of its solid state nature. STATCOM capacity does not suffer as seriously as SVCs and capacitors do from degraded voltage. STATCOMs are current limited - so their MVAR capability responds linearly to voltage as opposed to the voltage-squared relationship of SVCs and capacitors. This attribute greatly increases the usefulness of STATCOMs in preventing voltage collapse.

BLACK START CAPABILITY SERVICE

A blackout is a rare contingency, but it nevertheless does occur. In order to reduce the economical and social consequences, it is important to restore power as fast as possible. The system operator is then bestowed with the responsibility of restoring the system to normal operating state as soon as possible. However, restoration of the system after a major blackout is not an arbitrary process, but needs a methodic sequential approach. Restarting of large thermal power plants requires major chunk of electric power for its auxiliaries. On the other hand, the electric power resources like hydro plants, diesel generators, etc., can be started without help from the grid. The system operator is required to have enough of these resources at its disposal after blackout.During the restoration process, the energization of long transmission lines and the capability of generators to support reactive power creates major problem. Sometimes, under the deregulated environment, the restoration process may involve private generators and multiple transmission companies. In such situations, the financial compensation for these private entities adds a new dimension to the restoration process.The overall coordination of network facilities owned by different entities and allocation of costs of various support entities is hard to determine. Moreover, the 'worth' associated with this type of support is not a measurable quantity. Therefore, the system operator can make long term contracts so as to procure black start capability. However, technical capabilities of contracted generators and their locations need to be considered.

5. Explain the process of transmission expansion in a regulated power market (April/May 2008, Nov 2007)

Role of transmission Provider

The electric transmission system is one of the most complex man – made systems. Due tot the externality stemming from the operation of transmission system implementing market mechanism to the industry requires a fair level of understanding of not only economic, finicial and regulatory aspects but also engineering consequences of restructuring.

Fig 1 shows the evolution of role of TP in the industry.

In the dependent phase the TP functions as a part of vertically integrated utility.

In the passive phase the TP stands alone and oversees overall market activities. The market participants are required to submit their intended use of the system to the TP and based on the formation the TP allocates transmission capacities following the strict rules set by regulators. The TP assumes no financial responsibilities and has minimal interactions with market participants.

As shown in figure 1 there are three different structures of RP under this phase.

In the active phase the TP participates in every phase of market activities. The functions by TP under this phase can be categorized into two: of market maker and of service provider.

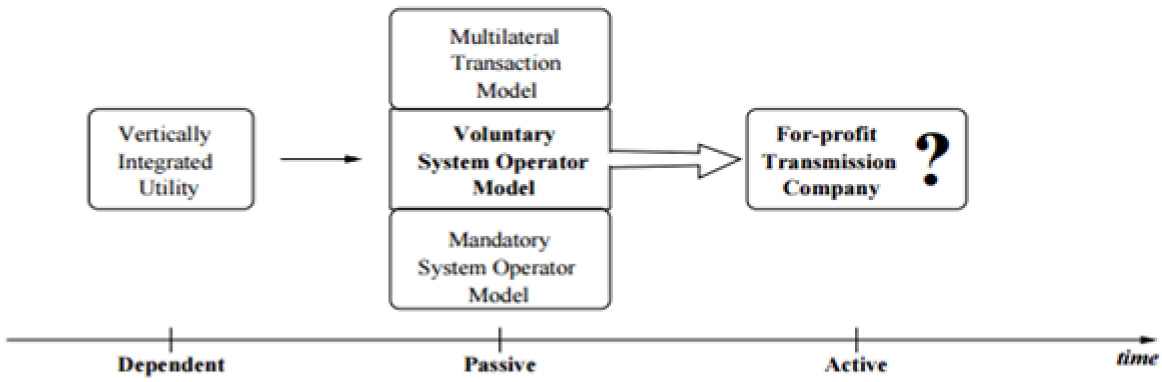


Figure 1 Role of Transmission Provider

Of these two only the function of market maker is under strict regulation. As a service provider the TP assumes full financial liability but is under no regulation.

We will discuss the role of the TP in each phase in details in the subsequent sections.

The operation and planning of the system by TP, therefore, can be viewed as a combined optimization problem of short – term generation scheduling and investment in new generation and transmission to balance load demand deviations ranging from hourly through seasonal and long– term and to do this at the lowest cost. A possible mathematical formulation of this problem is given as:

$$\min_{I_l^T, I_{i,g}^G, P_{i,g}} \varepsilon \left\{ \sum_i \int_{t_o}^{T} e^{-pt} \left(c_{i,a} \left(t, P_{i,a}(t) \right) + C_{i,a}^G (K_i^G(t), I_{i,a}^G(t), t) \right) dt \right.$$

$$\left. + \sum_i \int_{t_o}^{T} e^{-pt} \left(C_l^T (K_l^T(t), I_l^T(t), t) \right) dt \right\}$$

Subjected to:

$$\frac{dK_i^G}{dt} = I_{i,a}^G(t); \quad K_i^G(t_o) = K_{i,to}^G$$

$$\frac{dK_l^T}{dt} = I_l^T(t); \quad K_l^T(t_o) = K_{l,to}^G$$

$$I_{i,a}^G(t) \leq 0, \; I_l^T \leq 0$$

$$F_i\left(P_g(t), P_L\right) \leq F_i^{max} (K_t) : \mu_i(t)$$

$$P_{i,a}(t) \leq K_i^G \qquad : \eta_i(t)$$

$$\sum_{i=1}^{n} P_{i,a}(t) = \sum_{j=1}^{n_a} P_{L,j}(t) \qquad : \lambda(t)$$

where

K_i^G: the amount of installed generation capcity at node i

K_i^T: the amount of installed transmission capacity for line l

$I_{i,a}^G$: the rate of investement in generation capacity using technology a at node i

I_l^T : the rate of investment in transmission capacity fo line l

$C_{i,a}^G(K_i^G(t), I_{i,a}^G(t), t)$: the cost of investment using technology a at node i

$C_l^T(K_l^T(t), I_l^T(t), t)$: the cost of investment in line l

$P_{i,a}(t)$: the production using technology a at node i, at time t:

$$Pg(t) = [P_{1,a1}(t), \ldots\ldots\ldots\ldots P_{n,an}(t)]$$

$C_{i,a}$: the most of generation using technology a at node i, excluding

$P_{L,j}(t)$: the uncertain (uncontrolled) load at node j, at time t:

$P_L(t) = [P_1(t), \ldots\ldots\ldots\ldots P_n(t)]$

$F_i(P_g(t), P_L)$: the flow on line l as a function of ssytem generation and demand

$F_i^{max}(K_t)$: the maximum allowable flow on line l as a fucntion of amount of installed transmission capacity: due to security constraints,

$F_t << K_t$

ρ : discount rate of risk – free investment

$\mu_i(t), \eta_i(t), \lambda(t)$: Lagrangian multipliers for corresponding constraints.

The optimization period, T in the problem is no longer of two time intervals over which the genration or transmission investements are valued. A s the system operator/planner decides the level of production and the rate of investement on generation and transmision, $P_{i,n}(t)$, $I_{i,a}{}^{G}$ and I_t^T serve as control variable in this formulation. The state variables the system are $\mu_t(t)$, $\eta_i(t)$, K_i^G and K_t^T, for the status of the system operation can be accurately appreciated by examining these variables.

This formulation captirs many well-known trade-offs revelant for the efficiency of the power industyr: the relationship between the investement timing nad the balance of the costs and benefits over time, the value of different technologies at different locations used to prodcue power, and complementarity of genration capacity and transmission capacity .

There are two noticable features considering the operation and planning of the system by TP (as a part of vertically integrated utility) as the combined optimization problem: the apparent complexity of the problem and the implied assumptions of return on investement based on costs Ci,a^G, C_l^T and $C_{i,a}$. Due to the complexity, the solution to the problem is not readily available, and thus the actual operation and planning of the sytem are performed suboptimally in many cases. Plus, since the rate of return on investemtn is determined based on costs, the optimality condition of the formulation is limites to concering $P_{i,n}(t)$, $I_{i,a}{}^{G}$ and I_t^T. Neverthelss , the problem is a valuable benchmark in studing the efficiency of the industry as the restructuring takes place.

Three Models of Electriccity Market

In the passive pahse TP exist as the final authority in administrating the market actibities separate from the generation and distribution sectors and indifferent from the financial consequences in a amarket environment. A newly creted entity, called the system operator (or the frid operator), manages the system in order to ensore the independence of the TP. the specific functions carried out by the TP are tailored to the market structure of the region the TP serves.

The structureof markets, both exixting and developing, is highly non – uniform. Depending on particular regional characteristics some markets admit centralized day – ahead and hour – ahead markets for wholesale trading and a real-time energy market for balancing, while others only offer one or two centralized markets and still others offer only bilateral contracts among market participants with no centralized market. Most of the markets in various regions within the USA can be represented by one of three simplified market models: the multilateral transaction model, the mandatory system operator model and volunatry system operator model as shown in fig below.

The multilateral transaction model is based on bilateral tranasction among market participants. For example, the proposed structure of the MIDwest USO is closely related to the multilaterla transnaction model. The model consists of thee stages in completing tranactions. Firstly, individual buyers and sellers make bilateral trades with one another without disclosing the price and propose the agreed trades to the TP for physical Implementation. The TP, upon receiving the proposed transactions, makes decisions whether or not to allow the transactions based on an analyis of transmission network constraint. If the proposed transactions do not violate any constraints, then they are accepted without any modifications. This is the most desired case. If the proposed transactions results in violation of constraints, then the TP accepts none or a part of the proposed transactions and suggests necessary modifications to the transactions in the form of public information called loading vector. based on this information, the market participants make a new set of trades to satisfy the unmet demand while obsering sysem limmits. show the iteraction amog various market participants for the model. in this model, the function of the TP is limaited to verifying whether proposed transactions will result in violatio of system liits.

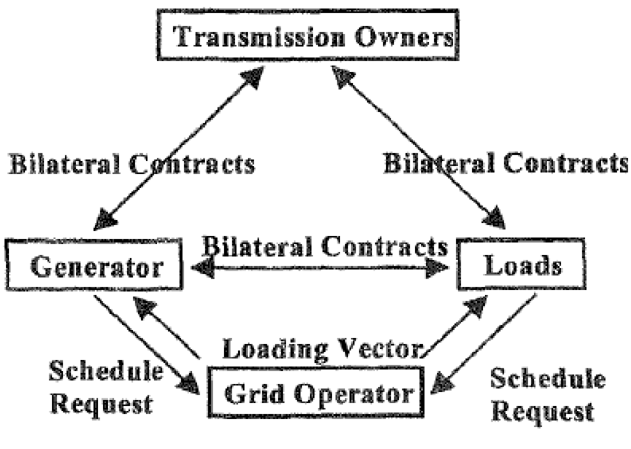
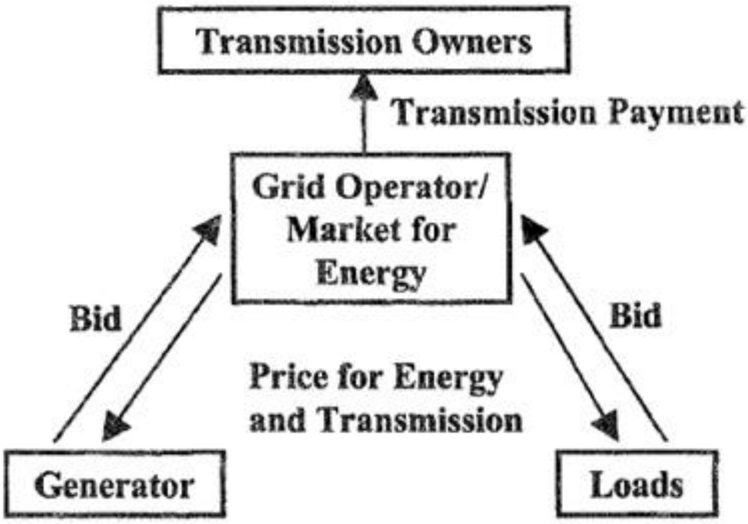


Figure Multilateral transaction model

The mandatory system operator model is developed based on the existing practices of tight power pools. the structure of the PJM ISO resembles the mandatory ystem operator model. in this model the TP becomes the sole centralized market maker for overseeing economically and functionally bundled energy and transmission trades. The spot market refers to a place where this type of centralized market-based trades takes place. Shows the relation among market participants.



Mandatory system operator model

Initially, market participants bid suppy curves to the TP, although a generalization can be made to include elastic demand in the formulation, for the rest of the chapter we assume the consumers, demand is inelastic since not much is lost in terms of the main purpose of the chapter. the TP then simultaneously dispatches generators and allocates transmission capacity using an optimal power flow program, which determines the most economical mix of generations for given load. The voluntary system operator model supports a multi-tiered structure that minimizes the TP's influence on profit by market participants while achieving acceptable levels or reliability**.**

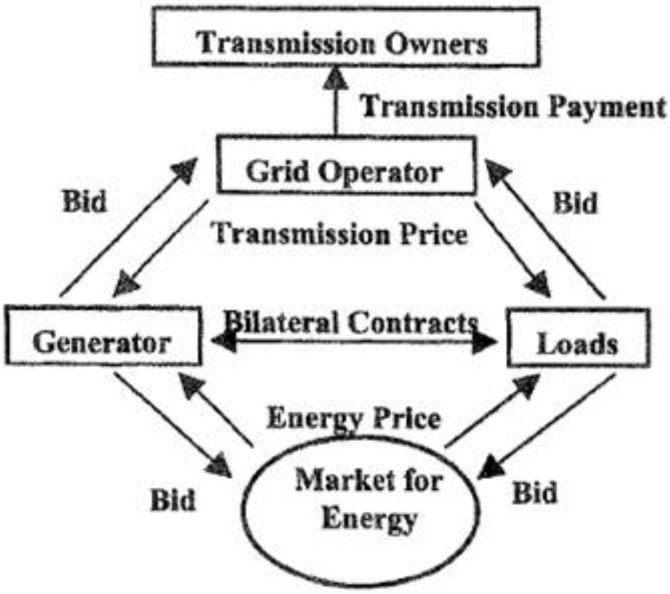


Figure Voluntary system operator model

In this model both bilateral and centralized market-based trades are allowed. The presence of spot market transactions is desired because of the requirement for continual balance of instantaneous supply with uncertain demand, particular to the electricity industry, while direct access and customer choice are achieved via bilateral trades.

The level of efficiency can be compared are each of the above three market structures by studying the operation and planning of the system under each structure. Under the perfect market assumption with complete information, both the multilateral transactions model and the mandatory system operator model lead to an equilibrium solution.

FOR – Profit TP

Before discussing the additional restructuring steps needeed in order to allow the TP to participate actively in the market process, it is important to understand the underlying reasoning behind many regulatory rules ensuring the independence of the TP from the generation sector and the distribution sector so that any regulatory change complies with the minimum requirement for independence based on the reaons given.

Unlike generation assets, the efficient operation of the transmission system requires a single grid configuration rather than multiple grids serving customers in the same geographical region. This is due to the high degree of the economics of scale and the economics of scope related to transmission.

By having a transmission system covering a wide area of the region, a large number of generators can be connected to a large number of customers. Under this configuration, the TP can serve the suppliers and consumers with a total transmission capacity smaller than the absolute sum of capacity demanded by individual transaction between suppliers and consumers. For example, this point is simple to illustrate through an example involving various transactions which commonly create counter flows on a single grid. Therefore, the TP as well as system users benefit from the economies of scale. In addition, by serving customers whose generation and consumption patterns differ from one another, a significant amount of system- wide savings can be achieved.

For instance, it is easy to show that the total generation capacity required to serve various loads is far smaller than the sum of peak consumption levels of each laod.. Thus, the TP enjoys the economies of scope.

Giving this monopolistic nature, a strict regulatory oversight is necessary when the TP takes on the role of a market maker. As a market maker, the TP allocates the transmission capacity by setting the price of energy and deciding which generating units are to be dispatched. This is an important function of the TP, especially at the time of scarcity in transmission capacity since this allocation process directly affects the profits of each market participant. It is not an overstatement to say that the success of deregulation in the industry depends on how well this process works so that the transmission capacity is distributed without resulting in distorted price signals and the overall electricity market achieves the highest efficiency level possible.

because the TP as a market maker exerts a considerable influence on each participant’s market actiities, much time and effort has been spent in establishing the pricing for the allocation of transmission capactiy which will promoate the efficeitn use of transmission and subsequently generation and consumptiom. The three market structures presentes in the previous section all attempt to achieve this objective. The function of the TP as a market maker is, therefore, under strict regulation and will remain so regardless of any future regulatory changes.

The Volunatry system operator model differs significantly from the other two models because the function of the TP is no longer limited to tha of a market maker. In the multilateral transactions model the TP operates as a market maker by supplying the information necessary in accommodatng bilateral trades. NO explicit price setting by the TP takes place in this model. Therefore, the transmission revenue is srictly equal to the level designated through the rate of return regulation. In the madatory system operator model, TP seta the bundled energy and transmission price that minimises the overall cost of satisfying the systm load aat each given instant. The transmission revenue in this model has two parts. The first cut is specified by computing the diffeernce between the marginal prices assigned to consumers and to suplliers. The differenece in the level of aloowed investement recovery and the computed first cut is then compensated through approved access fees and usage charges assigned to consumers.

In the voluntary system operator model the TP is ina unique position to assign an explicit price for using transmission capacity as a result of the dual functions required for furnishing explcit bilateral transactions requested by a subset of marketparticipants and for operating the spot market for the rest. The TP still assumes the role of a market maker in operating the spot market and is subjected to strict regulation as in the other two models. However, in allocating the necesssary transmission capacity for bilateral trades the TP functions as a service provider. As a service provider, the TP designs the appropriate transmission rates to be charged to each blateral trade implemeted wihtout the regulatory oversight.

In Implenetating bilateral trades the TO conducts business just as any other for-profit entities: for given variable and fixedcosts the TP functins in order to maximise profit. we refer to the for-profit TP as an independent transmission company(ITC).

An increase n profit can be achieved by increasing revenues and or/by decreasing costs. An increase in revenues is possible when the ITCcan only set the transmission rates to be charged to bulateral trades while the spot market is operaated under strict regulation, there is a clear ceiling to how much the price can be raised despite the monopolistic nature. On the contary, the ITC has every incentive to lower the rate in order to expand the customer base. Further, related to the expansion of the ciustomer basem, the system relaibility is expected to improve inorder to attract more customers.

6. Explain in detail about hedging in transmission environment.

By definition, in accounting for losses the aggregate of the FTR awards cannot be perfectly balanced. The net difference is the energy that would be required to meet the loss requirements of the

FTR dispatch. In principle, an individual FTR could be defined for inputs and outputs at any bus, in any combination or mix. In the aggregate, the simultaneous feasibility requirement is only that the net inputs must equal the net outputs plus losses. There is no need for individual FTRs to balance with losses, only for the aggregate to balance to preserve feasibility in the system.

Although a great deal of flexibility could be allowed, it is convenient to separate the key issues by defining two generic types of FTRs. Any pattern of simultaneously feasible FTRs could be decomposed into balanced FTRs between locations, with the inputs and outputs equal, and unbalanced FTRs at a location, where the requirement is to inject or withdraw a given amount of energy. Consistent with current implementations, we define these as FTR obligations.

Treatment of FTRs as options would be more complicated and would raise some additional issues not discussed in this paper. 2 Hence, a general FTR for 208 MW in at A and 200 MW out at B could be decomposed into a balanced FTR for 200 MW between A and B, and an unbalanced FTR of 8 MW in at A.

Each FTR would operate in the same way, being a financial contract to pay the difference in value for the withdrawals minus the injections. In the case of the balanced FTR, this is pB200-pA200 = (pB - pA) 200. In the case of the FTR at A this would be - pA8. In both cases, the FTR payment would exactly offset the payments in the spot market if the holder's schedules matched its FTR holdings. The transmission charge to the participant for the movement of 200 MW in the spot market would be (pB - pA) 200, and the payment to the participant for 8 MW of energy would be pA8. If the participant always injected 208 MW and withdrew 200 MW, there would be no net payments by the participant.

Furthermore, to the extent that the participant actually had the ability to inject 208 MW and withdraw 200 MW and submitted bids reflecting the incremental costs of these injections and withdrawals, any deviation from schedules matching the FTR holdings, with the accompanying net payments for FTRs and spot transactions, would be profitable compared to following a schedule matching the FTR holdings. Whether the hedge would reduce or increase the cost of the transaction, however, would depend on the price of the hedge, the amount of the unbalanced obligation, and the actual levels of energy prices and marginal losses, both in the hours in which the transactions flows and those in which it does not. Once purchased, however, either a balanced or unbalanced FTR would lock in the cost of losses associated with the hedged transaction, as well as the congestion costs.

The ISO could award both balanced and unbalanced FTRs in a single auction. Market participants could bid for any mix of balanced and unbalanced FTRs they chose. The auction problem would reduce to a form of economic dispatch with the side constraint that some bids for inputs and outputs must be individually balanced. There would be a market clearing price for each type of FTR, and the awards would be made at the market clearing price, not the amount bid. The mix of FTRs awarded would be determined in the auction to maximize the aggregate value as measured by the bids, subject to the constraint that the awards would be simultaneously feasible.

Explain about the Financial Transmission Rights.

The use of economic dispatch addresses the strong interactions of power flows in an electrical network. For equilibrium to hold at the efficient economic dispatch, the difference in market-clearing locational spot prices must equal the opportunity cost of transmission. Therefore, the consistent spot price for transmission is this difference in locational prices. If it were not for the strong interactions in the network, it would have been possible to define a set of physical rights for transmission, and these physical rights could have been traded to produce an efficient use of the network. In equilibrium, the spot price of these tradable transmission rights would be equal to the spot price of transmission under economic dispatch.

The replacement for the unworkable physical transmission rights is the financial transmission right (FTR) to collect the difference in the locational prices. (Hogan, 1992) Spot electricity prices are volatile, and the transmission spot price is even more volatile. The FTR is the right to collect the difference in the locational prices. In effect, the FTR is the equivalent of a physical right sold at the spot price without the necessity of actually trading the physical right. This provides a hedge for physical transactions between locations. The physical transaction incurs a spot charge at the difference in the locational prices. The FTR pays the differences in the locational prices. If the physical and financial transactions are exactly matched, then the net payments cancel as though the schedule had used the physical transmission right. From the perspective of the physical schedule, the transaction connects the source to the destination at the cost of acquiring the FTR. Hence, the FTR provides a hedge for the difference in locational prices.

The revenue to fund payments under the FTRs arises from the short term transmission rents in the economic dispatch at spot prices. The total payments by load exceed the payments to generators, reflecting the differences in losses and congestion that make up the spot market surplus. If the allocation of FTRs is simultaneously feasible for the grid conditions used in the economic dispatch, then under certain regularity conditions, the net of the spot market payments in the physical market will support the payments for the FTRs. (Hogan, 2002)

Allocation of FTRs can occur in a variety of ways. For example, a rolling or periodic auction can provide a market for FTRs covering a given forward period extending to months or years. The auction design includes an estimate of the applicable grid conditions in order to apply the simultaneous feasibility condition that underpins revenue adequacy. Additions to the grid can accommodate expansions and changes in the configuration of FTRs that preserve simultaneous feasibility. The fidelityof the estimated grid conditions is important in guaranteeing revenue adequacy. Changes in the flow of power or the configuration of load and generation would not affect the revenue adequacy result. But unplanned changes in the transmission network could make the existing FTRs infeasible. To the extent that grid conditions change in unexpected ways, payments under the FTRs might not be fully funded by contemporaneous spot market revenues. (PJM, 2012a)

Practical implementation of FTR definitions typically apply only to the congestion component of LMPs. The spot price can be decomposed into the reference cost of energy, the marginal cost of congestion and the marginal cost of losses. The reference cost of energy is the same for all locations and nets out for the locational difference in LMPs, leaving the difference in marginal costs for congestion and losses. The difference in the marginal cost of losses is less volatile than the difference in the marginal cost of congestion. Further, to include losses in the FTR definition requires an external party to provide a hedge for the total losses associated with the putative power flows in the FTR allocation. This is not true for the congestion component. If losses were zero, only the congestion difference in locational prices would apply. Hence, many models and most discussion apply only to FTR definitions for the difference in the congestion costs, and the difference in the charges for margin al losses remains unhedged. (Hogan, 2002)

The definition of FTRs includes possible treatment as obligations or options. In the case of obligations the holder of the FTR receives payment when the difference in congestion costs is positive and makes a payment when the difference in negative. Under the FTR option, the case of negative difference in congestion costs does not require a payment. The mix of options and obligations affects the simultaneous feasibility of FTRs. But for the present discussion the differences are not important and the focus of discussion is on the treatment of FTR obligations. The FTR provides a critical piece in the elements of a workable and efficient electricity market design under the principles of open access and non-discrimination. The core contribution is in providing a substitute for the unavailable physical transmission rights that tie together the sometimes large locational differences in market conditions and associated LMPs. The existence of FTRs creates the opportunity to replicate many other features of efficient markets with an array of forward contracts and hedging instruments.

srivenkateshwaraa College of Engineering & Technology
(Approved by AICTE, New Delhi & Affiliated to Pondicherry University, Puducherry)
13-A, Pondy - Villupuram Main Road, Ariyur, Puducherry - 605 102.
ASPIRE TO EXCEL

DEPARTMENT OF ELECTRICAL & ELECTRONICS ENGINEERING

Subject Name: **POWER SYSTEM RESTRUCTURING AND DEREGULATION**

Subject Code: **EE E89**

Prepared by:

1. Mrs.S.Punitha , AP/EEE
2. Mr.V.Malarselvam, AP/EEE

Verified by: *Approved by:*

UNIT – IV MARKET PRICING

Transmission pricing in open access system-Introduction-Spot pricing-Uniform pricing-Zonal pricing-Locational Marginal pricing-Congestion pricing-Ramping and opportunity cists. Embedded costs based transmission pricing methods(Postage stamp, Contract path and MW –mile)-Incremental cost based transmission pricing methods Short run, Marginal cost, Long run marginal cost)-Pricing of losses on lines and nodes.

PART-B

1. Explain the following transmission pricing methods.

(a) Postage Stamp Method

Postage stamp methodology is the simplest and easy to implement methodology of transmission pricing. A postage stamp rate is a fixed charge per unit of power transmitted within a particular zone. The rate does not take into account the distance involved in the wheeling. There are various versions of postage stamp methodology. In some versions, both, generators and loads are charged for transmission usage, while in others, only loads pay for the same. Some variants charge loads for their peak value while in others, they are charged on the basis of average loads. A simpler version of postage stamp mechanism is explained with the help of following illustration.

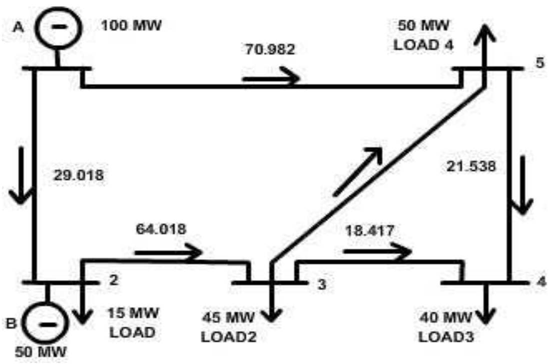


Figure 3: Sample 5 bus system

Suppose that the rolled-in cost of a region INR1000/day and that there are bilateral transactions as shown in Table 1.

Sr.No	**From Bus**	**To Bus**	**MW**
1	1	4	40
2	2	2	15
3	2	3	35
4	1	5	50
5	2	3	10

Table 1: Bilateral Transactions

There are various ways of expressing the postage stamp rates. Normally it is given in INR/ MW/ day for Indian system. Let us assume that the loads make the whole payment towards the transmission charges. Then, the transmission charges paid by each load will be proportional to its MW. Hence, the transmission price paid per day by each load will be as given in Table 7.2.

Sr.No	**Load**	**Charge per Day (INR)**
1	15	100
2	45	300
3	40	266.67
4	50	333.33

Table 2: Transmission Charges by Postage Stamp Method

The postage stamp rates are based on average system costs and may have a variety of rate designs based on energy charges, capacity charges, or both. Rates may include separate charges for peak and off-peak periods, may vary by seasons and in some cases may be different for weekdays and weekends.

Some of the advantages of Postage Stamp Method are as follows:

- The method is simple and easy to implement.
- It is transparent and is easily understood by all.
- There is no mathematical rigor involved.
- Recovers sunk cost of transmission system.

- Being very simple and straightforward, it is easy to get political backing for it to be implemented.

Disadvantages of the Postage Stamp Method can be quoted as follows:

- Pancaking: In case a transaction takes place such that the power is transmitted through multiple intermittent utilities or zones, pancaking of access charges takes place.
- No economic signal: With regard to the principles discussed in the earlier sections, postage stamp allocation does not create an economic signal associated with the effect of a particular transaction.
- No extent of use of network: Postage stamp allocation does not take into consideration the extent of use of the network by a particular transaction. The transmission charges paid by two loads, out of which, one is very near to a generator, while the other is miles apart, is the same. It is obvious that transmission network use by the other load is more than the first.

(b) Contract Path Methodology

This method is based on charging the transacting entities between two points, based on a pre-defined path. To define formally, contract path is the shortest route formed by a series of transmission lines which can carry the contract power between the take-off point and injection point. In the earlier days, when the wheeling contracts were rare, the contracts were used to be written between the utility and the contracting parties. Hence, the word contract in the name. Even though contracting parties know that the power will split into multiple parallel paths, they compute the prices for a single path.

For example, assume that power is being wheeled from the state of Orissa to the state of GU as shown in Figure 7.5. The contract path would be as shown in the left hand side figure. However, there are bound to be multiple parallel paths when power flows from Orissa to GU, as shown in the right hand side of the figure. To get the feel of how charges are calculated under this scheme, assume the contract is for 100 MW, with the contract path as shown in the figure. Then, if the capacity of Orissa-CH corridor is 200 MW, this transaction will be charged 50 % of the cost of this line. Similarly, if capacity of CH-MH corridor is 100 MW, the whole cost of the line would be attributed to this transaction.

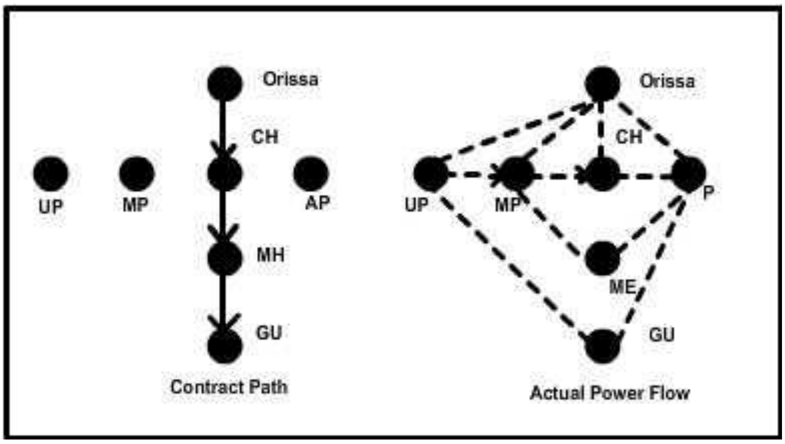


Figure 5: Contract Path Method

This method is viable, rather justified, in a system where the network is not so cramped and hence, it is easy to determine the length of a contracted path to a great extent in such cases. Suppose the transactions of Table 7.1 are to be charged as per the contract path, then Table 7.3 shows the contract paths and associated transmission charges for each of the transactions are shown in Table 7.4.

Line	Capicity (MW)	Transmission Charges (INR/MW/Time Duration)
1-2	50	1.0
2-3	70	1.5
3-4	40	0.75

3-5	10	0.5
1-5	100	1.0
4-5	50	1.0

Table 7.3: Transmission Charge Corridor

Sr. No	Transaction Between	Transaction Amount	Contract Path	ChargeCalculation	Transmission Charges
1	1-4	40	1-2-3-4	40 x (1+1.5+0.75)	130
2	2-2	15	-	-	-
3	2-3	35	2-3	35 x (1.5)	52.5
4	1-5	50	1-5	50 x (1)	50
5	1-3	10	1-2-3	10 x (1+1.5)	25

Table 7.4: Contract Path Charges

The prices for transmission lines will be in INR/MW/Duration time. Some of the advantages of this methodology are as follows:

- This method is simple to implement, though not as simple as postage stamp rate method.
- irectly or indirectly, the method takes into account the distance involved in wheeling.
- Avoids pancaking to a large extent.

(C) MW-Mile Methodology

This method overcomes the limitations of the contract path method. This method bases the cost on a computed set of parallel paths for a particular transaction. The method employs power flow simulation to determine the flow of a transacted power in various lines. There are two versions of the MW-Mile methodology. The first version which is a non-power flow method is an approximate method. It does not make use of any power flow simulation.

- **Distance Based MW-Mile Methodology**

Distance based MW-Mile method evaluates the usage of each user according to the product of the quantity of the transacted power and the geographical distance between the source and sink. This is quite a rough method. In practice, due to the effect of meshed network, there is no fixed relationship between the geographical distance and the actual costs.

This is a simple, easy to calculate and easy to apply method. It can be called as a version of the contract path method. However, this method does not take into consideration the effect of actual power flow and transmission users do not face their actual costs. This does not lead to efficient operation of power systems.

- **Power Flow Based MW-Mile Methodology**

Power flow based MW-Mile method takes into account both the quantity of transacted power and the electrical distance between source and sink and allocates the total costs in proportion to the MW-Mile of transactions. There are various versions of power flow based MW-Mile methods. The original MW-Mile method suggested by [8] states that:

Given a transaction with the actual points and the variation of generation and load specified, MW-Mile methodology calculates the maximum transaction related power flow on every transmission line using a DC power flow.

For transaction t, according to MW-Mile methodology, real power flows on all network lines are calculated using the DC power flow algorithm. The magnitude of MW flow on every line is then multiplied by its length L1 and a predetermined weighting factor reflecting the cost per unit capacity of the line, W1and summed over all network lines. This leads to:

$$MWMile_t = \sum_1 W_1 MW_{t,1} L_1$$

....(7.1)

This process is repeated for every transaction by considering only the generations and loads associated with that transaction. The share of the total transmission network capacity cost, TC, allocated to transaction t can be calculated according to the following formula:

$$TC_t = TC \frac{MWMile_t}{\sum_t MWMile_t}$$

....(7.2)

The main characteristic of MW-Mile methodology is that we need to determine the usage or influence of each transaction on each branch. Based on this, there are various versions of MW-Mile approach. The concept of power flow based MW-Mile method is explained with the help of illustrative example of Figure 7.6. The figure shows a 3 bus system.

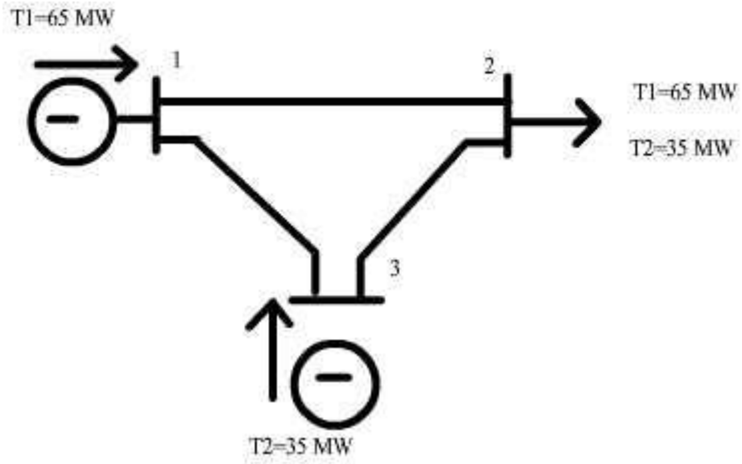


Figure 7.6: Illustrative example for MW-Mile methodology

Details about the network elements are given in Table 7.5.

Sr. No	Element	Reactance p.u	Ll	Wl	Pmax
1	1-2	X12=0.2	200	0.25	100
2	3-2	X32=0.25	100	0.5	50
3	1-3	X13=0.4	100	0.5	50

Table 7.5: Details of network elements

Total transmission network capacity cost is calculated as follows:

$$TC_t = \sum_l W_l P_{max,l} L_l$$ 7.3

Thus, TC comes out to be INR 10,000. Assume that base case power flows are zero. Suppose two bilateral transactions are taking place as shown in the figure:

1. T1= 65 MW between generator at bus 1 and load at bus 2
2. T1= 65 MW between generator at bus 1 and load at bus 2

		Line 1 -2	**Line 3-2**	**Line 1-3**	**MWMilet**	**TCt**
T1=65 MW	Flow (MW)	50	15	15	4000	6400
	MWMile t,l	2500	750	750		
T1=65 MW	Flow (MW)	10	25	10	2250	3600
	MWMile t,l	5001-3	1250	100		

Since this methodology allocates transmission charges based on maximum usage of a transmission line by a transaction, it emulates the actual planning process for system reinforcements which is based on local considerations rather than coincident peak condition for the overall system.

The advantages of this method can be stated as follows:

- It is insensitive to the order of wheeling transactions. This is because every transaction is treated separately by considering only those generators and loads that are associated with that transaction. Hence, there will be no dispute about the order in which the transactions should be considered.
- It gives a correct signal to both short distance and long distance entities, unlike in postage stamp case.
- The method is intuitively logical and conceptually straightforward.

Some of the drawbacks of the above methodology are:

- Since the method uses DC approximation of the power system, it leads to inaccuracy in calculating the extent of use of the network by a particular transaction. This is because, the real power system is modeled by a set of non-linear equations.

- No merit is attributed to the transactions which give rise to counter flows, thereby reducing loading of the system.

2. How transmission pricing is calculated using rolled in pricing method and marginal pricing methods. Compare the advantages with each method.

ROLLED-IN TRANSMISSION PRICING METHODS

In this paradigm, all the costs incurred during building the infrastructure and the future investment, operating, maintenance costs are summed up (rolled-in) together and then are allocated to various wheeling customers on various basis. The basic philosophy behind this paradigm of transmission pricing paradigm is shown in Figure 7.2.

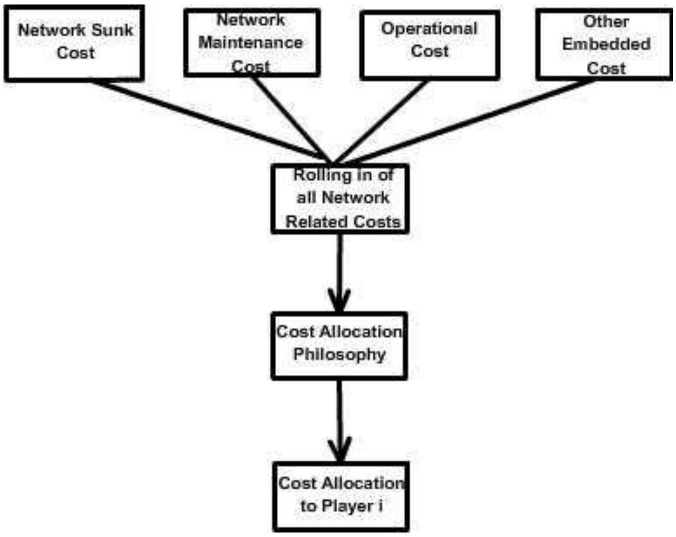


Figure 7.2: Rolled-in Paradigm

Effectively, this boils down to directly or indirectly quantifying the extent of usage of the network by each transaction. The diversity of underlying assumptions, methodologies, etc. lead to many choices or versions of methods under this category. Some of the commonly practiced methods are as follows:

MARGINAL TRANSMISSION PRICING PARADIGM

According to this paradigm, only the new transmission costs caused by the new transmission customers will be considered for evaluating transmission charges for these customers. The existing system costs will remain the responsibility of utilities' present customers. The basic philosophy lying behind this paradigm is shown in Figure 7.10.

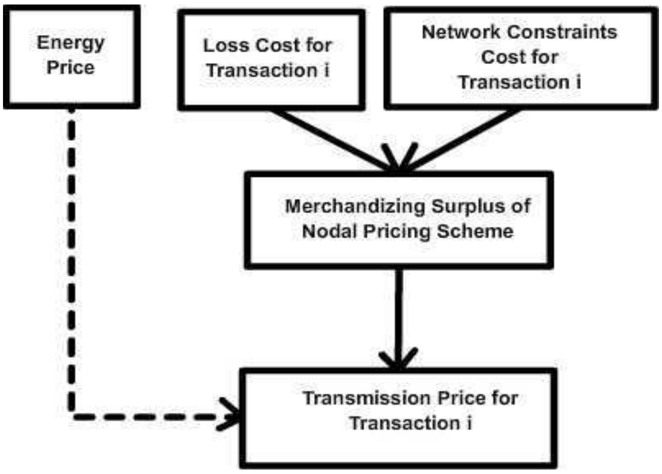


Figure 7.10: Incremental Paradigm

In contrast to the philosophy of rolled-in methods, the embedded costs (sunk costs) are not taken into account, but the additional transmission cost a transaction causes is attributed to the transaction itself. Under this scheme, marginal cost of energy is calculated, which includes loss and network constraint components. Depending on the time-frame under consideration, the marginal costs can be classified as short-run and long-run.

As we have seen in Chapter 2, for short-run considerations, the transmission capacity is considered to be fixed, while for long-run pricing schemes, it is assumed that new capacities can be built. Thus, long-run marginal cost includes the reinforcement and expansion cost as well as the operating cost. Short-run marginal costs only reflect the operating costs of the existing facilities

Short-run Marginal Cost Pricing (SRMC)

The foundation of this methodology is based on the theory of spot pricing [9]. Under the marginal pricing schemes, the general idea is to model an electricity market with its various economical and technical specifications such as generators' cost functions, demand elasticity, generation limits, power flow limits, etc. Then, this system is optimized with the objective of maximizing the social welfare. An important outcome of this optimization is the nodal price at each load, which is popularly known as Locational Marginal Price. It reflects the temporal and spatial variation of the energy price relating to the energy demand [9]. Because of losses and system security (line limits), a kWh of energy has different values at different busses of the network. Since wheeling is analogous to buying energy at one set of buses and selling it at another set, these spatial price differences determine the cost of wheeling. The optimal spot price at bus i defined as in [2] is given as:

{cost of additional demand at ith bus} =

{cost of additional demand at swing bus} x{1+ incremental losses caused by i} + {transmission constrained terms summed over lines}

We have seen the details of nodal spot price (or LMP) calculation in Chapter 5. Recalling the simplistic expression for spot price,

$$\rho_i = \lambda\left[1 + \frac{\partial L}{\partial d_i}\right] + \sum_j \frac{\partial Z_j}{\partial d_j}\eta_j$$

....(7.18)

Where,

nj......Shadow price of line j, nj=0 if line flow limit is not reached

λ..... System lambda

Pi...... Optimal spot price at bus i

di....Demand at bus i

L.....Transmission Losses

Zj.....Line flow in line j

With no transmission constraints and losses neglected, there will be only one system lambda, i.e. one system price for the whole network. As this methodology comprehends that the electricity not only has to be generated, but also has to be delivered to a particular load, taking into account transmission constraints and electrical losses, the difference in nodal prices then gives the marginal network revenues (NR), which is nothing but the SRMC for that particular transaction. To define formally, the marginal operating cost per MW of transacted power can be estimated as the difference in the optimal cost of power at all points of delivery and receipt of that transaction. The marginal operating cost is then multiplied by the magnitude of the transacted power to yield the SRMC for the transmission transaction. It can be given by the following equation:

$$SRMC_t = \sum_{i \in B_t} \rho_i P_{i,t}$$

....(7.19)

where, Pi is the bus i marginal cost, Pi,t, the injected power at bus i due to transaction t and Bt the set of transmission buses involved in the transaction t. This is explained with an illustrative example of Figure 11.

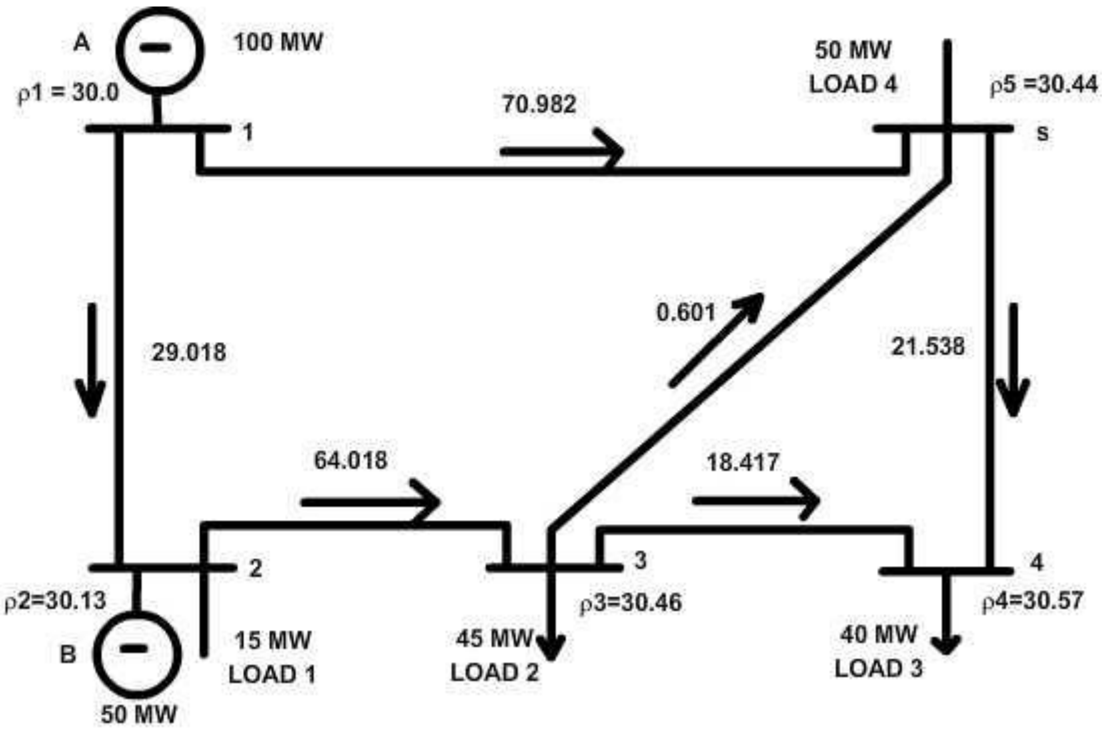


Figure 11: Incremental Paradigm

The Pis indicate the short run nodal prices of bus i. If bilateral transactions of Table 7.1 are assumed to take place, then each transaction pays a charge as shown in Table 7.9.

Sr.No	Tranction Between	Difference of Nodal prices	Transmission Charges (INR)
1	1-4	0.57	22.8
2	2-2	0	0
3	2-3	0.13	5.85
4	1-5	0.44	22

Table 9: Wheeling charges as per marginal pricing scheme

With the marginal cost based pricing method, it is possible that the transmission fixed costs (embedded or sunk costs) may not be recovered fully. This is because, no constraint in the network results in zero network revenues (if lossless model is considered). This will not be acceptable to the transmission owner company. As stated in [5], the spot pricing recovers the total incurred network costs only in the case where the installed system capacity is optimal. Hence, to recover the sunk costs, a top-up of the charges is required to be done. This leads to the composite paradigm of pricing which is explained later.

Long-run Marginal Cost Pricing (LRMC)

In the calculation of SRMC, it was assumed that the transmission capacity is fixed. For calculation of LRMC, this assumption is removed. To define formally, the LRMC are the costs of increasing the production by one unit, allowing changes in the overall system capacity, i.e., reinforcing the system. For the optimal capacity of the network, LRMC and SRMC are equal. In this pricing methodology, the marginal operating and reinforcement costs of the power system are used to determine the prices for a transmission transaction. Marginal operating cost was defined in the earlier section. The marginal reinforcement cost is calculated as follows [10]:

“Over a long time horizon of several years, all transmission expansion projects are identified and their costs are taken into account. This cost is then divided over the total power magnitude of all new planned transactions to calculate the marginal reinforcement cost.”

In other words, the LRMC of a transmission transaction is the sensitivity of the network capacity cost to the quantity of the transmitted power, that is, the least network reinforcement costs needed by per unit increment of power transmission. Accurate calculation of LRMC is very difficult and some assumptions and simplifications are done. These are as follows:

- the capacity of transmission lines can be increased continuously.
- there are no new right of ways
- the peak demand condition is considered.
- all the lines are of the same type.
- the costs for lines are linear functions of branch capacities.

Under these assumptions, the LRMC becomes the sensitivity of the system MW-Mile to the quantity of the transmitted power [1].

Classification of Loss Allocation Methods

The loss allocation methods developed so far can be classified into three broad categories as follows:

- Pro-rata loss allocation methods
- Incremental loss allocation methods

- Proportional sharing loss allocation methods

We will see some details of these methods one by one. It should be remembered that these loss allocation methods are ex-post mechanisms and have nothing to do with the loss supply decisions in the scheduling process.

Pro-rata Methods

In these methods, the total loss is first divided between two groups: generator losses and load losses. The percentage losses in each category are pre-defined. The losses are then allocated to each generator or load in proportion to its generation or consumption, respectively. Let,P_L represent the total system losses. Let α_G be the fraction of total losses allotted to generators and α_D be the fraction of total losses allotted to loads, such that,

$$\alpha_G P_L + \alpha_D P_L = P_L \quad \text{.......(7.27)}$$

$$\alpha_G + \alpha_D = 1 \quad \text{.......(7.28)}$$

Thus, losses allotted to individual generators and loads are given as:

$$P_{G_i}^{loss} = \alpha_G P_L \frac{P_{G_i}}{\sum_i P_{G_i}} = K_G P_{G_i} \quad \text{.......(7.29)}$$

$$P_{D_j}^{loss} = \alpha_D P_L \frac{P_{D_j}}{\sum_j P_{Dj}} = K_D P_{D_j} \quad \text{.......(7.30)}$$

Where, we define KG and KD as generation and load loss allocation factors, respectively.

Incremental Methods

These methods calculate the incremental transmission loss (ITL) coefficients. The ITL is defined for a bus and quantifies the change in total losses produced by an incremental change in the power injected on that bus. The ITLs are obtained from a converged power flow solution.

$$ITL_i = \frac{\partial P_L}{\partial (P_{Gi} - P_{Di})} \quad \text{.......(7.31)}$$

Thus, straightforward loss allocation to generators i and loads j is:

$$P_{G_i}^{loss} = P_{G_i} ITL_i \quad \text{.......(7.32)}$$

$$P_{D_j}^{loss} = -P_{D_j} ITL_j \quad \text{.......(7.33)}$$

It is easy to appreciate that due to non-linearity associated with power flows, the following situation arises:

$$P_L \neq \sum_{i=1}^{n_G} P_{G_i}^{loss} + \sum_{j=1}^{n_D} P_{D_j}^{loss} \quad \text{.......(7.34)}$$

So, we need to allocate the normalized losses such that sum of allotted losses equals total system losses. Let normalized incremental transmission loss coefficient be defined as

$$\overline{ITL_i} = ITL_i \frac{P_L}{P_L^{1}} \quad \text{.......(7.35)}$$

Where

$$P_L^{'} = \sum_{i=1}^{n_G} P_{G_i} ITL_i - \sum_{j=1}^{n_D} P_{D_j} ITL_j \quad \text{.......(7.36)}$$

Thus,

$$P_L = P_L^{'} \frac{P_L}{P_L^{'}} = \left(\sum_{i=1}^{n_G} P_{G_i} ITL_i - \sum_{j=1}^{n_D} P_{D_j} ITL_j \right) \frac{P_L}{P_L^{'}} \quad \text{.......(7.37)}$$

Hence, the loss allotted to individual generators and loads will be:

$$P_{G_i}^{loss} = P_{G_i} ITL_i^{'} \quad \text{.......(7.38)}$$

$$P_{D_j}^{loss} = -P_{D_j} ITL_j^{'} \quad \text{.......(7.39)}$$

It is worthwhile to note that the losses allotted to individual generators and loads may come out to be negative. Another matter of debate about this method is that the results are dependent on the choice of slack bus.

Power flow tracing based loss allocation

We have seen principles of tracing based on proportionate sharing principle in section 7.3. Equation 7.5 shows us how to allocate losses to individual generators. Thus, topology dependent loss allocation is done using proportionate tracing methods. The loss allocation under this scheme is also called as average loss allocation.

Other Methods

There are several other approaches for loss allocation which do not fit into any of the above three classes [12, 29, 30]. Here, Z-Bus method developed in [12] is explained. The Z-bus loss allocation method is based on expressing total system losses in simple manner related directly to the equations describing a solved load flow condition. If all generators and loads are represented as current injections into the system, total losses can be expressed according to:

$$P_{loss} = \left\{ \sum_{i=1}^{n} I_i^* \left[\sum_{j=1}^{n} Z_{ij} I_j \right] \right\} \qquad \text{.........(7.40)}$$

$$P_{loss} = R\left\{ \sum_{i=1}^{n} I_i^* \left[\sum_{j=1}^{n} R_{ij} I_j \right] \right\} + R\left\{ \sum_{i=1}^{n} I_i^* \left[\sum_{j=1}^{n} R_{ij} I_j \right] \right\} \qquad \text{.........(7.41)}$$

In [12], it is shown that in a network that can be represented by a symmetrical impedance matrix, the second component in the above equation becomes zero. Thus, loss allotted to bus i is

$$L_i = R\left\{ I_i^* \left[\sum_{j=1}^{n} R_{ij} I_j \right] \right\} \qquad \text{.........(7.42)}$$

Locational Marginal Pricing

PJM manages congestion through a market design based on Locational Marginal Pricing. The Locational Marginal Price (LMP) is defined as: “The marginal cost of supplying the next increment of electric demand at a specific location (node) on the electric power network, taking into account both generation marginal cost and the physical aspects of the transmission system.” (Ott 1998) Figure 4.3.1 provides a representation of the PJM Locational Marginal Pricing Model.

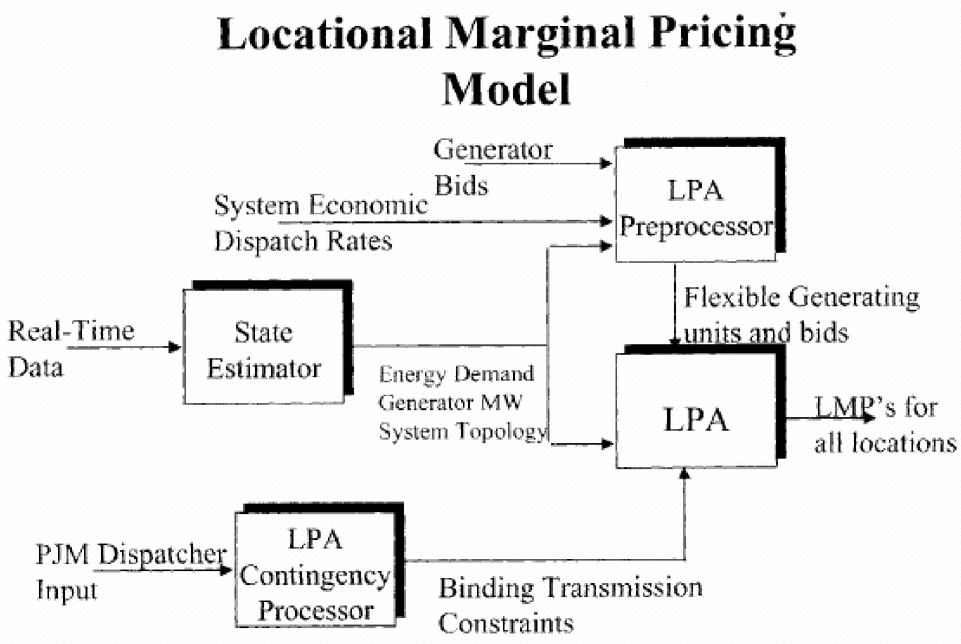


Fig. 4.3.1 PJM Locational Marginal Pricing Model

Model Components for Locational Marginal Pricing

State Estimator

• Model of the conditions that currently exist on the PJM power system based upon metered input and an underlying mathematical model.

Locational Price Algorithm (LPA)

• Calculates locational marginal prices based on actual system conditions at five minute intervals

LPA Contingency Processor

• A mechanism for PJM dispatchers to enter binding transmission constraints and controlling actions into the LMP calculation process .

LPA Preprocessor

• Determines which generating units are eligible to participate in the LMP calculations

Determining Locational Marginal Prices

The LMPs used by PJM are location specific. They include the marginal cost of generation and the cost to deliver energy to the specific location due to congestion. The LMPs are generated at five-minute intervals and immediately posted on OASIS. The LMPs are calculated for 1,750 PJM busses plus 5 interface busses into the PJM control area. When there are no congestion constraints in the PJM system, then the LMPs are the same at all busses and equal to the marginal cost to serve load in the control area. (PJM 1998).

The LMPs are calculated by minimizing the difference between the bids for generation and load subject to transmission constraints. The LMP model generates sensitivity factors from the transmission constraints that determine the dispatch of generating units. These sensitivity factors are calculated to avoid congestion at the lowest system wide cost. For locations (busses) where there are transmission constraints, the dispatched units (in order to operate within the constraint) will have higher costs than the lowest marginal cost-generating unit. The increase over the marginal cost generating unit will depend on the dispatch necessary to meet the loads within the transmission constraints. All power transactions pay the LMP for the relevant busses regardless of whether the transaction results from dispatch by the SO or the transaction is bilateral (self scheduled).

PART-A

1. What is Postage Stamp Method?

Postage stamp methodology is the simplest and easy to implement methodology of transmission pricing. A postage stamp rate is a fixed charge per unit of power transmitted within a particular zone. The rate does not take into account the distance involved in the wheeling. There are various versions of postage stamp methodology. In some versions, both, generators and loads are charged for transmission usage, while in others, only loads pay for the same. Some variants charge loads for their peak value while in others, they are charged on the basis of average loads. A simpler version of postage stamp mechanism is explained with the help of following illustration.

2. What does availability tariff address?

The Availability Tariff directly addresses these issues. Firstly, by giving incentives for enhancing output capability of power plants, it enables more consumer load to be met during peak load hours. Secondly, backing down during off-peak hours no longer results in financial loss to generating stations and the earlier incentive for not backing down is neutralized. Thirdly, the shares of beneficiaries in the Central generating stations acquire a meaning, which was previously missing.

3. What is long run marginal pricing?

In this pricing methodology, the marginal operating and reinforcement costs of the power system are used to determine the prices for a transmission transaction. Marginal operating cost was defined in the earlier section.

What is called embedded cost recovery?(Nov 2013)

Define congestion pricing.(April 2015)

Define short run marginal cost. .(April 2015)

What is the difference between embedded cost based and incremental cost based pricing methods. (April/May 2014)

Define system marginal rate. (April/May 2014)

DEPARTMENT OF ELECTRICAL & ELECTRONICS ENGINEERING

Subject Name: **POWER SYSTEM RESTRUCTURING AND DEREGULATION**

Subject Code: **EE E89**

Prepared by:

1. Mrs.S.Punitha , AP/EEE

2. Mr.V.Malarselvam, AP/EEE

Verified by: *Approved by:*

UNITV: INDIAN POWER MARKET

Current Scenario– Regions–Salient features of Indian Electricity Act2003–Regulatory and Policy development in Indian power Sector–Availability based tariff–Necessity–Working Mechanism–Unscheduled Interchange Rate– Operation of Indian Power Exchange.

UNIT – V

1. **Explain the current scenario of restructuring the choices and salient features of Indian electricity Act 2003.(April 2015,April/May 2014)**

National Power Scenario Indian power sector is facing challenges and despite significant growth in generation over the years, it has been suffering from shortages and supply constraints. Energy and peak load shortages were 7.8 % and 13 % respectively in the year 2000-01. The per capita electricity consumption in India is about 400 kWh/year, which is significantly lower than the world average of around 2,100 kWh/year. As GDP growth accelerates to an ambitious 8 to 10 %, the shortage of power will become more severe.

The power situation in India is characterized by demand in excess of supply, high Transmission and Distribution (T&D) losses, low Plant Load Factor (PLF), peak demand and energy shortages, poor financial health of the State Electricity Boards (SEBs) and severe resource crunch. The power sector reforms in the country and consequent privatization of generation, T & D have been sluggish, due to complexities involved. The Ministry of Power has been making continuous efforts for promoting reduction of T&D loss and re-structuring of SEBs. The electricity regulatory commissions, recently formed as a part of the reforms, have been still learning to exercise adequate control on power tariffs.

With reference to above power and energy scenario, Ministry of Power (MoP) and Ministry of Non-conventional Energy Sources (MNES), Government of India, has been promoting viable renewable energy technologies including wind, small hydro and biomass power, energy conservation, demand side management etc. MNES has been promoting various sources of renewable energy since 1990.

Wide spread need of power generation has created the need for a cheap and readily available commercial fuel for generating electricity at low cost. Coal was the first to be selected in India as a commercial fuel in early thermal power stations and is still king of the power market.

Central Electricity Authority (CEA) has initially projected a shortfall of 1,50,000 MW in 15 years and therefore, a capacity addition target of 10,000 MW every year, the actual capacity addition has been far short of targets. The CEA has recently revised the capacity addition target to 1, 00,000 MW from earlier target. This implies an annual addition of 8,500 MW as against earlier fixed of 10,000 MW. Capacity addition in the last five years including financial year 2000 was average 3,000 MW per year. Out of the total capacity added during last five years, 49% was added by the states and balance by central plants, excluding only 4% contributed by private sector. This indicates that, the states have been the largest contributors to incremental capacity.

The sustained economic development in India has created a critical need for additional power generation capacity. To augment the existing installed capacity of about 101,154 MW (year 2000-01), the Government of India has encouraged private sector participation in the power generation.

To assess the all India capacity requirements by the end of eleventh plan to meet the demand projected by 15th Electric Power Survey (EPS) report, Central Electricity Authority (CEA) carried out planning studies using updated version of Integrated System Plan (ISPLAN) model, which optimizes generation capacity additions in an integrated manner with power transmission and fuel transportation. The studies are based on updated data base, keeping in view the development in power sector in recent past, likely achievement during 9th Plan, the perspective plans prepared by Central Power Units (CPUs) and also latest status of Independent Power Producers (IPP) and state sector projects.

The CEA report “Power on Demand By 2012” has indicated that the level of satisfaction would be 85% only with the identified installed capacity of about 2,10,000 MW by the end of eleventh Plan (2011-12), leaving a gap of about 22,600 MW in demand. Additional projects to the tune of 30, 000 MW capacity need to be identified to meet the full peaking requirements. On the other hand, if the demand in terms of peak as well as energy is reduced by 15%, then the present level of identified projects including projects covered in CPUs perspective plan is found to be adequate. Hence, energy conservation activities and power generation from renewable sources have an important role in management of demand and energy requirement.

Out of total existing generation capacity, nearly 72% is contributed by thermal power. With a need for sustainable economic growth, the Government of India, through the Ministry of Non-Conventional Energy Sources (MNES), is encouraging and catalyzing the growth of renewable energy based power including biomass, wind, hydro, solar photo-voltaic etc. It is expected that a judicious mix of centralized fossil fuel power plants and decentralized renewable energy based power plants will lead to an environmentally friendly augmentation of the power sector in India. In addition to this central government and all the State Governments are encouraging the Energy conservation activities in all the sectors like industrial, domestic, commercial, agricultural etc. Implementation of electrical energy conservation projects / programmes at various sectors will also help in reduction of peak demand along with the financial gains through reduction of energy consumption.

2. **Explain the regulatory and policy development in Indian power sector briefly.(April 2015)**

- The Electricity Act of 2003 is one of the key policy acts in the Power Sector „
- This act encourages private sector involvement in Generation, Transmission and Distribution „
    - Open Access Provisions are provided in the Act wherein private generators can sell directly to consumers „
- Privatization and Corporatization of SEB's is encouraged „
        - State Governments pay off or write-off the debts of the SEB's „
- Competition is promoted in Generation and Distribution „
- Unbundling of Generation, Transmission and Distribution is proposed in order to increase the number of players in this sector and thereby promote efficiency, consumer choice and satisfaction „
- Cross subsidies will be reduced and State governments will pay SEBs the subsidies they mandate. SEBs can also set appropriate tariffs so that they are financially viable
- Multi-year Regulation through CERC (Central Electricity Regulatory Commission) and SERC (State Electricity Regulatory Commission) have been established to monitor activity in this sector „
- Although these reforms have been well intended, the current taxation structure and government bureaucracy have not allowed these reforms to have their intended effect
- APDRP – Accelerated Power Development and Reform Program. Some highlights are …
    - States unbundle Generation, Transmission and Distribution, and take over SEB debts …

- States agree to an audit, use of IT and Metering …
- Investment is provided to upgrade infrastructure „
  - Preference is given to programs aimed at removing commercial losses „
  - Funding is contingent on whether targets were met for previous projects …

- Incentives provided for improved reliability, loss reduction, billing and metering „
  - Incentive amount is pegged to reduction in difference between cost of production and revenue „
- Bottom Line – there were initial improvements in some SEBS like WB, AP. However, now enthusiasm to implement reforms has decreases.

3. What is Availability Tariff? Explain in detail

The term Availability Tariff, particularly in the Indian context, stands for a rational tariff structure for power supply from generating stations, on a contracted basis. The power plants have fixed and variable costs. The fixed cost elements are interest on loan, return on equity, depreciation, O&M expenses, insurance, taxes and interest on working capital. The variable cost comprises of the fuel cost, i.e., coal and oil in case of thermal plants and nuclear fuel in case of nuclear plants. In the Availability Tariff mechanism, the fixed and variable cost components are treated separately. The payment of fixed cost to the generating company is linked to availability of the plant, that is, its capability to deliver MWs on a day-by-day basis. The total amount payable to the generating company over a year towards the fixed cost depends on the average availability (MW delivering capability) of the plant over the year. In case the average actually achieved over the year is higher than the specified norm for plant availability, the generating company gets a higher payment. In case the average availability achieved is lower, the payment is also lower. Hence the name 'Availability Tariff'. This is the first component of Availability Tariff, and is termed 'capacity charge'.

The second component of Availability Tariff is the 'energy charge', which comprises of the variable cost (i.e., fuel cost) of the power plant for generating energy as per the given schedule for the day. It may specifically be noted that energy charge (at the specified plant-specific rate) is not based on actual generation and plant output, but on scheduled generation. In case there are deviations from the schedule (e.g., if a power plant delivers 600 MW while it was scheduled to supply only 500 MW), the energy charge payment would still be for the scheduled generation (500 MW), and the excess generation (100 MW) would get paid for at a rate dependent on the system conditions prevailing at the time. If the grid has surplus power at the time and frequency is above 50.0 cycles, the rate would be lower. If the excess generation takes place at the time of generation shortage in the system (in which condition the frequency would be below 50.0 cycles), the payment for extra generation would be at a higher rate.

To recapitulate, the Indian version of Availability Tariff comprises of three components: (a) capacity charge, towards reimbursement of the fixed cost of the plant, linked to the plant's declared capacity to supply MWs, (b) energy charge, to reimburse the fuel cost for scheduled generation, and (c) a payment for deviations from schedule, at a rate dependent on system conditions. The last component would be negative (indicating a payment by the generator for the deviation) in case the power plant is delivering less power than scheduled.

How do the beneficiaries share the payments?

The Central generating stations in different regions of the country have various States of the Region as their specified beneficiaries or bulk consumers. The latter have shares in these plants calculated according to Gadgil formula, and duly notified by the Ministry of Power. The beneficiaries have to pay the capacity charge for these plants in proportion to their share in the respective plants. This payment is dependent on the declared output capability of the plant for the day and the beneficiary's percentage share in that plant, and not on power / energy intended to be drawn or actually drawn by the beneficiary from the Central station.

The energy charge to be paid by a beneficiary to a Central station for a particular day would be the fuel cost for the energy scheduled to be supplied from the power plant to the beneficiary during the day. In addition, if a beneficiary draws more power from the regional grid than what is totally scheduled to be supplied to him from the various Central generating stations at a particular time, he has to pay for the excess drawn at a rate dependent on the system conditions, the rate being lower if the frequency is high, and being higher if the frequency is low.

How does the mechanism work?

The process starts with the Central generating stations in the region declaring their expected output capability for the next day to the Regional Load Dispatch Centre (RLDC). The RLDC breaks up and tabulates these output capability declarations as per the beneficiaries' plant-wise shares and conveys their entitlements to State Load Dispatch Centres (SLDCs). The latter then carry out an exercise to see how best they can meet the load of their consumers over the day, from their own generating stations, along with their entitlement in the Central stations. They also take into account the irrigation release requirements and load curtailment etc. that they propose in their respective areas. The SLDCs then convey to the RLDC their schedule of power drawal from the Central stations (limited to their entitlement for the day). The RLDC aggregates these requisitions and determines the dispatch schedules for the Central generating stations and the drawal schedules for the beneficiaries duly incorporating any bilateral agreements and adjusting for transmission losses. These schedules are then issued by the RLDC to all concerned and become the operational as well as commercial datum. However, in case of contingencies, Central stations can prospectively revise the output capability declaration, beneficiaries can prospectively revise requisitions, and the schedules are correspondingly revised by RLDC.

While the schedules so finalized become the operational datum, and the regional constituents are expected to regulate their generation and consumer load in a way that the actual generation and drawls generally follow these schedules, deviations are allowed as long as they do not endanger the system security. The schedules are also used for determination of the amounts payable as energy charges, as described earlier. Deviations from schedules are determined in 15-minute time blocks through special metering, and these deviations are priced depending on frequency. As long as the actual generation/drawal is equal to the given schedule, payment on account of the third component of Availability Tariff is zero. In case of under-drawal, a beneficiary is paid back to that extent according to the frequency dependent rate specified for deviations from schedule.

4. Why was Availability Tariff necessary?

Prior to the introduction of Availability Tariff, the regional grids had been operating in a very undisciplined and haphazard manner. There were large deviations in frequency from the rated frequency of 50.0 cycles per second (Hz). Low frequency situations result when the total generation available in the grid is less than the total consumer load. These can be curtailed by enhancing generation and/or curtailing consumer load. High frequency is a result of insufficient backing down of generation when the total consumer load has fallen during off-peak hours. The earlier tariff mechanisms did not provide any incentive for either backing down generation during off-peak hours or for reducing consumer load / enhancing generation during peak-load hours. In fact, it was profitable to go on generating at a high level even when the consumer demand had come down. In other words, the earlier tariff mechanisms encouraged grid indiscipline.

The Availability Tariff directly addresses these issues. Firstly, by giving incentives for enhancing output capability of power plants, it enables more consumer load to be met during peak load hours. Secondly, backing down during off-peak hours no longer results in financial loss to generating stations and the earlier incentive for not backing down is neutralized. Thirdly, the shares of beneficiaries in the Central generating stations acquire a meaning, which was previously missing. The beneficiaries now have well-defined entitlements, and are able to draw power up to the specified limits at normal rates of the respective power plants. In case of over-drawal, they have to pay at a higher rate during peak load hours, which discourages them from overdrawing further. This payment then goes to beneficiaries who received less energy than was scheduled, and acts as an incentive/compensation for them.

How does it benefit everyone?

The mechanism has dramatically streamlined the operation of regional grids in India. Firstly, through the system and procedure in place, constituents' schedules get determined as per their shares in Central stations, and they clearly know the implications of deviating from these schedules. Any constituent which helps others by under-drawal from the regional grid in a deficit situation, gets compensated at a good price for the quantum of energy under-drawn. Secondly, the grid parameters, i.e., frequency and voltage, have improved, and equipment damage correspondingly reduced. During peak load hours, the frequency can be improved only by reducing drawls, and necessary incentives are provided in the mechanism for the same. High frequency situation on the other hand, is being checked by encouraging reduction in generation during off-peak hours. Thirdly, because of clear separation between fixed and variable charges, generation according to merit-order is encouraged and pithead stations do not have to back down normally. The overall generation cost accordingly comes down. Fourthly, a mechanism is established for harnessing captive and co-generation and for bilateral trading between the constituents. Lastly, Availability Tariff, by rewarding plant availability, enables more consumer load to be catered at any point of time.

5. Write about the daily scheduling process.

Suppose a 1000 MW Central coal-fired power station has three beneficiaries (States – A, B and C) with allocated shares of 30, 30 and 40% respectively. Suppose the station foresees a capability to deliver 900 MW (ex-bus) on the next day, and advises the same to the RLDC by 9 AM. The RLDC would break it up, and advise the three SLDCs by 10 AM that their entitlements in the Central station are 270, 270 and 360 MW respectively, for the next day. Entitlements in the other Central stations would also be advised by RLDC to the SLDCs similarly.

Simultaneously, the SLDCs would receive availability status from their intra- State stations as well. They would then carry out a detailed exercise as to how best to meet the expected consumer demand in their respective States over the 24 hours. For this, they would compare the variable costs of various intra - State power stations inter-se, and with energy charge rates of the Central stations, and also consider the irrigation release requirements vs. energy availability of the hydro-electric stations. After this exercise, the SLDCs will issue the dispatch schedules for the intra - State stations, and their requisition from the Central stations (restricted to the States' respective entitlements). Suppose States – A and B fully requisition their shares from the Central station under consideration (270 MW each, throughout the 24-hour period), while State – C requisitions 360 MW during the day time, but only 200 MW during the night hours.

Summation of the three requisitions would thus produce, for the Central generating station, the total dispatch schedule of 900 MW during the day time and 740 MW during the night hours, as illustrated in figure - 1. This would be issued by the RLDC by 5 PM, and would be effective from the following midnight (unless modified in the intervening hours). States – A, B and C shall pay capacity charge for the whole day corresponding to plant availability of 270, 270 and 360 MW, and the generating station would get capacity charge corresponding to 900 MW. Energy charge payments by the three States would be for 270 x 24 MWh, 270 x 24 MWh, and (200 x 24 + 160 x 16) MWh of energy respectively, at the specified energy charge rate of the generating station.

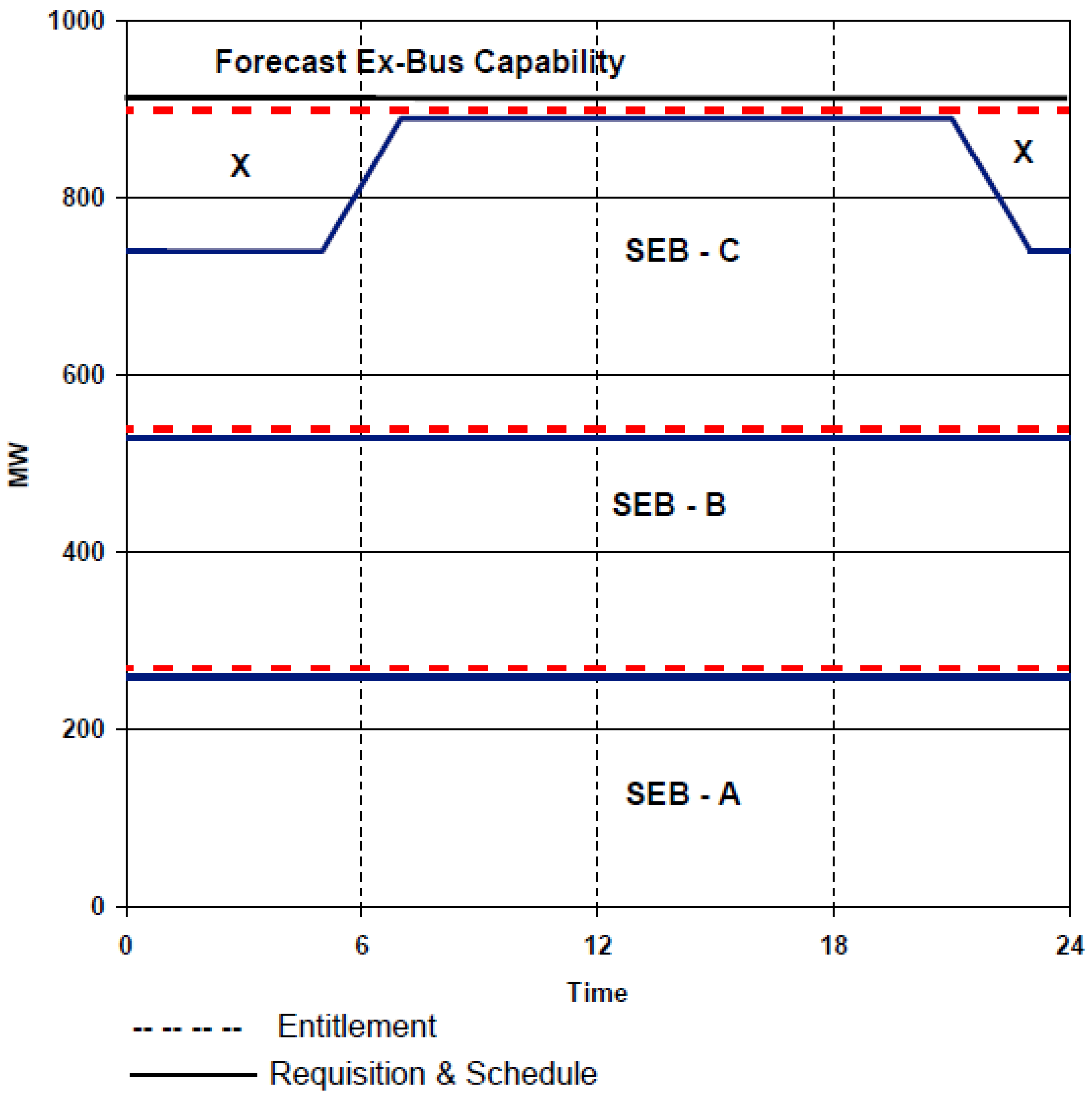


Figure - 1

DEVIATIONS FROM SCHEDULE

As mentioned earlier, the energy charge, at the specified energy charge rate of a generating station, is payable for the scheduled energy quantum. The energy actually supplied by the generating station may differ from what was scheduled. If actual energy supplied were higher than scheduled, the generating station would be entitled to receive a payment for the excess energy (the deviation from schedule, technically termed as Unscheduled Interchange (UI) in Availability Tariff terminology) at a rate dependent on frequency at that time. If the energy actually supplied is less than what is scheduled, the generating station shall have to pay back for the energy shortfall, at the same frequency - linked rate.

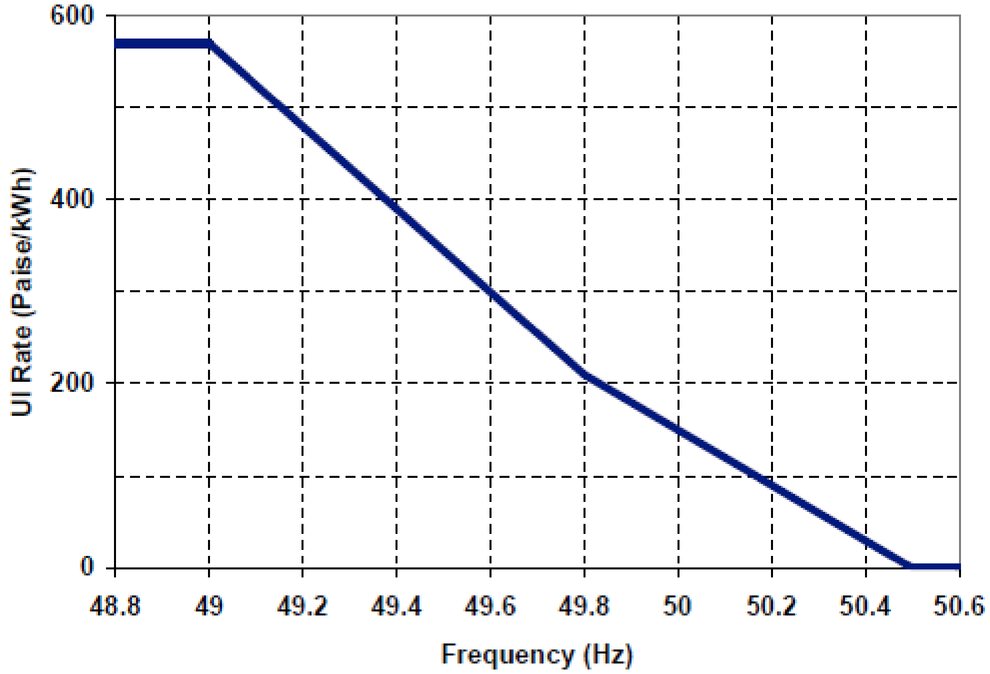


Figure – 2

The relationship between the above UI rate and grid frequency, for the inter- State system, is specified by CERC. The present relationship, applicable from 1.10.2004, is shown in figure - 2. When the frequency is 50.5 Hz or higher, the UI rate is zero, which means that the generating station would not get any payment for the extra energy supplied. It would burn fuel for producing this extra energy, but would not get reimbursed for it at all. Conversely, if the actual energy supplied were less than scheduled energy, the generating station would still be paid for the scheduled energy (at its energy charge rate) without having to pay back anything for the energy shortfall. It would thus be able to save on fuel cost (for the energy not generated) and retain the energy charge as net saving. There is thus a strong commercial incentive to back down generation during high frequency situations, and help in containing the frequency rise.

On the other hand, when frequency goes down, the UI rate (for both oversupply and under-supply) ramps up, reaching a ceiling level of Rs. 5.70 per kWh at a frequency of 49.0 Hz. At a frequency of 49.5 Hz, the UI rate is Rs. 3.45 per kWh presently. Under this condition, any extra energy sent into the grid would get the generating station a UI payment at the rate of Rs. 3.45 per kWh. For any shortfall, the generating station shall have to pay back at the same rate. It would thus have a strong commercial incentive to maximize its generation during periods of such low frequency.

A similar scheme operates for the States (beneficiaries) as well. Any State drawing power in excess of its schedule has to pay for the excess energy at the same frequency - dependant rate. The high UI rate during low-frequency conditions would induce all States to reduce their drawal from the grid, by maximizing their own generation and/or by curtailing their consumer load. If a State draws less power than scheduled, it pays for scheduled energy quantum at the normal rate and gets paid back for energy not drawn at a much higher UI rate. On the other hand, during high-frequency conditions, a State can draw extra power at a low rate, and is thus encouraged to back down its own costlier generating stations. An underdrawal during high-frequency conditions means that the State pays for the scheduled power quantum unnecessarily. It should either reduce its schedule, or increase its drawal.

For the above purpose, the energy is metered in 15-minute time blocks, since frequency keeps changing (and the UI rate with it). The metered energy is then compared with the scheduled energy for that 15-minute time block, and the difference (+ or -) becomes the UI energy, as illustrated in figure - 3. The corresponding UI rate is determined by taking the average frequency for the same 15-minute time block into account.

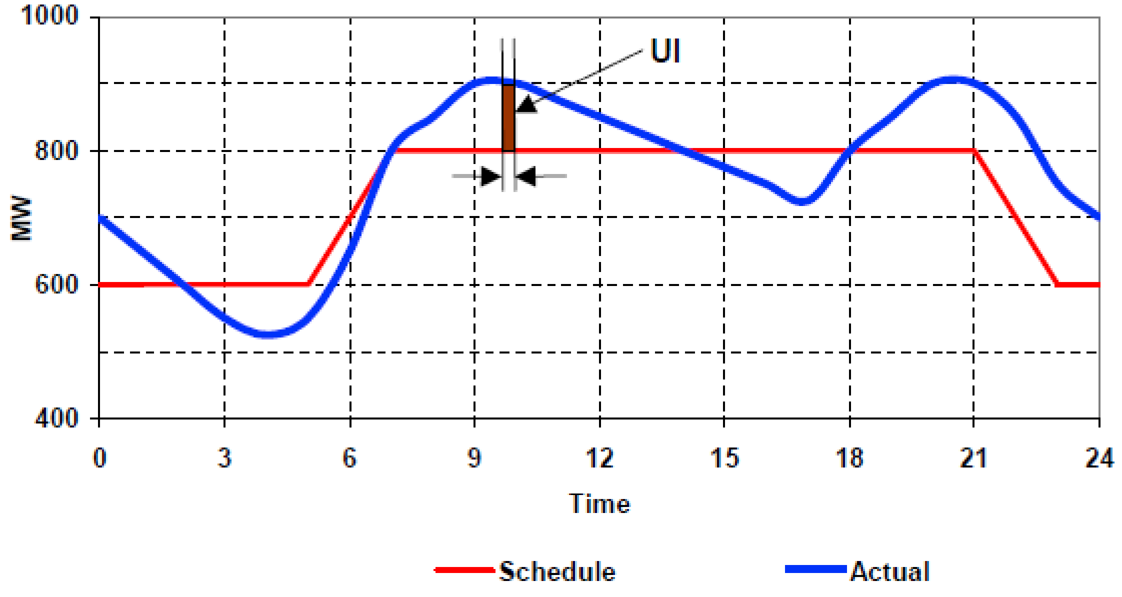


Figure - 3

Also, for each Central generating station and State, the actual energy has to be metered on a net basis, i.e., algebraic sum of energy metered on all its peripheral interconnection points, for every 15-minute time block. All UI payments are made into and from a regional UI pool account, operated by the concerned RLDC.

6. List the salient Features of Indian Electricity Act 2003

The main basic features of the Electricity Act, 2003 are briefly stated as follows:

1. There is a provision for private transmission licenses.

2. Distribution licenses would be free to undertake generation.

3. There would be a Transmission Utility at the central and State level.

4. Generation is being delicensed not as before and captive generation is freely permitted.

5. The State Electricity Regulatory Commission may permit open access in distribution in phases.

6. There is direct commercial relationship between the consumer and generating company or a trader.

7. There is a provision for transfer scheme.

8. System for generation as well as distribution will be permitted in the rural and remote areas.

9. There is a provision for Constitution of Central Electricity Authority.

10. There is provision for Constitution of Central Commission as well as the State Commission.

11. There is provision for Constitution of Central Advisory Committee as well as the State Advisory Committee.

12. There is provision for Establishment of Fund by the Central Government and the State Government.

13. There is provision for Establishment of Appellate Tribunal for adjudicating the grievances face by the Consumers etc.

14. There is provision for Offences and Penalties to be imposed on the person/ persons on the charge of Theft of Electricity such as materials, damaging work, stolen property etc.

15. There is provision for Exclusion of Jurisdiction of the Civil Court for speedy adjudication.

16. There is provision for Constitution of Special Courts for the trial of special cases.

17. There is provision for Arbitration open to the Consumers, Company etc. for arriving settlement with less time and resources.

The Electricity Act, 2003 has been enacted and a provision contained in this Act has come into enforce w.e.f 10th June, 2003 and the Act extend to the whole of India accept to State of Jammu & Kashmir. This Act of 2003 is now regulating the generation transmission, distribution, trading and use of electricity in the country.

7. Explain the role of Transmission system operator.

A **transmission system operator** (**TSO**) is an entity entrusted with transporting energy in the form of natural gas or electrical power on a national or regional level, using fixed infrastructure. The term is defined by the European Commission. The certification procedure for Transmission System Operators is listed in Article 10 of the Electricity and Gas Directives of 2009. Due to the cost of establishing a transmission infrastructure, such as main power lines or gas main lines and associated connection points, a TSO is usually a natural monopoly, and as such is often subjected to regulations.

In electrical power business, a TSO is an operator that transmits electrical power from generation plants over the electrical grid to regional or local electricity distribution operators.

In natural gas business, a TSO receives gas from producers, transports it via pipeline through an area and delivers to gas distribution companies.

The United States has similar organizational categories: independent system operator (ISO) and regional transmission organization (RTO).

Role in electrical power transmission

Safety and reliability are a critical issue for transmission system operators, since any failure on their grid or their electrical generation sources might propagate to a very large number of customers, causing personal and property damages. Natural hazards and generation/consumption imbalances are a major cause of concern. To minimize the probability of grid instability and failure, regional or national transmission system operators are interconnected to each other.

Electricity market operations

The role of the System Operator in a wholesale electricity market is to manage the security of the power system in real time and co-ordinate the supply of and demand for electricity, in a manner that avoids fluctuations in frequency or interruptions of supply. The System Operator service is normally specified in rules or codes established as part of the electricity market.

The System Operator function may be owned by the transmission grid company, or may be fully independent. They are often wholly or partly owned by state or national governments. In many cases they are independent of electricity generation companies (upstream) and electricity distribution companies (downstream). They are financed either by the states or countries or by charging a toll proportional to the energy they carry.

The System Operator is required to maintain a continuous (second-by-second) balance between electricity supply from power stations and demand from consumers, and also ensure the provision of reserves that will allow for sudden contingencies. The System Operator achieves this by determining the optimal combination of generating stations and reserve providers for each market trading period, instructing generators when and how much electricity to generate, and managing any contingent events that cause the balance between supply and demand to be disrupted. System Operations staff undertake this work using sophisticated energy modelling and communications systems.

In addition to its roles of real-time dispatch of generation and managing security, the System Operator also carries out investigations and planning to ensure that supply can meet demand and system security can be maintained during future trading periods. Examples of planning work may include coordinating generator and transmission outages, facilitating commissioning of new generating plant and procuring ancillary services to support power system operation.

(2 MARKS)

1. **What are the aims and objectives of electricity policy?**

The national electricity policy aims at achieving the following objectives:

- Access to electricity- available for all households in next 5 years
- Availability of power – demand to fully met by 2012 energy and peaking shortages to be overcome and adequate spinning reserve to be available.
- Supply of reliable and quality power of specified standards in an efficient manner at reasonable rates.

2. **What is reliability index?**

Reliability index of supply of power to consumers should be indicated by the distribution license.

A road map for declaration of RI for all cities and towns upto the district headquarter towns as also for rural areas should drawn up by SERCS the data of RI should be compiled and published by CEA .

3. **Write short notes on Energy Conservation.**

There is a significant potential of energy savings through energy efficiency and demand side management measures. in order to minimize the overall requirement energy conservation and demand side management is being accorded high priority.

4. **Write short notes on Electricity Act 2003.**

The Electricity Act, 2003 has been enacted and a provision contained in this Act has come into enforce w.e.f 10th June, 2003 and the Act extend to the whole of India accept to State of Jammu & Kashmir. This Act of 2003 is now regulating the generation transmission, distribution, trading and use of electricity in the country.

5. **What is the importance of electricity?**

Electricity is an important requirement for all facts of our life. It has been recognized as a basic human need. It is a critical infrastructure on which the socio-economic development of the country depends. Supply of electricity at reasonable rate to rural is essential for its overall development.

6. What does availability tariff address?

The Availability Tariff directly addresses these issues. Firstly, by giving incentives for enhancing output capability of power plants, it enables more consumer load to be met during peak load hours. Secondly, backing down during off-peak hours no longer results in financial loss to generating stations and the earlier incentive for not backing down is neutralized. Thirdly, the shares of beneficiaries in the Central generating stations acquire a meaning, which was previously missing.

7. What are the advantages of availability based tariff?

- Facilitates Merit Order Dispatch. Means because of clear separation between fixed and variable charges, generation according to merit order is encouraged and pithead stations do not gave the back down normally. The Overall generation cost accordingly comes down.
- Faster settlement process.
- Voltages improved, Transmission losses reduced, Transmission capacity increased.
- high quality metering and on line connectivity enabling the system operator to know the actual flows and taking appropriate action.

8. What are the opportunities for IPPs in electricity act 2003?

Independent Power Producers (IPPs) or non-utility generator (NUG) are private entities (under unbundled market), which own and or operate facilities to generate electricity and then sell it to a utility, central government buyer and end users. IPPs may be privately-held facilities, cooperatives or non -energy industrial concerns capable of feeding excess energy into the system.

9. Benefits of IIPs to Consumers?

- Promotes power supply competition and price transparency that results in lower cost and added value for consumers
- Benefits are realized without cost obligations associated with including generation assets in state jurisdictional rate base.
- IPPs add liquidity and price convergence between Day-Ahead and
- Real-Time Markets through their market participation, including taking FTR positions to hedge asset positions.

- Geographic diversity of generation portfolio capitalizes on regional differences in power prices and weather driven demand
- IPPs provide an important voice in MISO stakeholder forums – ensure balance of interests being heard/represented

10. What is ABT?(April/May 2014)(Nov 20102)

The term Availability Tariff, particularly in the Indian context, stands for a rational tariff structure for power supply from generating stations, on a contracted basis. The power plants have fixed and variable costs. The fixed cost elements are interest on loan, return on equity, depreciation, O&M expenses, insurance, taxes and interest on working capital. The variable cost comprises of the fuel cost, i.e., coal and oil in case of thermal plants and nuclear fuel in case of nuclear plants. In the Availability Tariff mechanism, the fixed and variable cost components are treated separately. The payment of fixed cost to the generating company is linked to availability of the plant, that is, its capability to deliver MWs on a day-by-day basis. The total amount payable to the generating company over a year towards the fixed cost depends on the average availability (MW delivering capability) of the plant over the year. In case the average actually achieved over the year is higher than the specified norm for plant availability, the generating company gets a higher payment. In case the average availability achieved is lower, the payment is also lower. Hence the name 'Availability Tariff".