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MODELLING AND ANALYSIS OF COMPETITIVE ELECTRICITY MARKET IN BHUTAN

Master of Science Thesis in the Programme Electric Power Engineering

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ABSTRACT

The power sector deregulation process has taken place over the past three decades world-wide with the objectives being more choices available to the customers and increased social welfare. Bhutan is also considering deregulating its own power sector in the near future with the pressure to reduce electricity costs to the customers. This thesis therefore aims at developing a preliminary proposal for a competitive electricity market for the Bhutan's existing power system and also presenting various technical requirements for the market to function properly. In this proposal, complete market models for competitive generators are developed and tested using PowerWorld Simulator. The models simulate the day-ahead electricity markets for two basic market pricing structures: uniform market pricing (mostly used in Europe) and locational marginal cost based pricing (LMP) (mostly used in North America). The market models are able to facilitate competitions among generators, calculate total generation costs, market clearing prices, costs of system securities, etc.

The study of the market analysis tried to compare the outcomes from the proposed competitive markets to those of the existing system. The results have shown that the price of electricity reduces comparatively in the proposed competitive market. The average market price came down by 21% (including the existing wheeling charge) for uniform market pricing market and 13% in LMP based market as compared to the existing system 0.182 SEK/kWh. The network loss calculated taking supply-demand balance in the existing system is 14.7% and the loss reduces to 4.54 % with the new market models. The total generation cost was found reduced in the competitive market as compared to the existing systems. The day-ahead spot market for both winter and summer loads showed very small or almost no changes in price for hourly variation of load in both uniform and LMP based market. It can be concluded the uniform market pricing structure could be appropriate for the current power systems in Bhutan since it's power network had no problem of transmission congestion and it would remain so even for certain load growths in the future. However, the LMP-based market has other advantages over network treatments incorporated in the market settlement itself and can be more beneficial in the long-run. The study has also pointed out the various technical requirements for a market to functions, namely ancillary services for network management, power balancing, etc. The issues of privatization of power generating companies and separation from network companies have also been discussed. A complete long-range study taking into account all sorts of generations and ancillary services costs would therefore be needed to make a final choice.

Keywords: Deregulation, Day-ahead Market, LMP, Uniform Price Market, Electricity, Bhutan power system.

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1. CHAPTER 1 : INTRODUCTION

This chapter gives brief background of deregulated market around the world and the motivations and objective for carrying out this thesis. It also provides scope of this thesis work with assumptions made and limitations.

1.1. BACKGROUND

The deregulation of power sector or the regulatory reform towards competitive market in the world was first started in Chile in 1980 when the government decided to privatize the electricity sector. Since then Chile saw its share of success and failure offering valuable lesson for other countries that moved towards liberalization of their electricity market in later years. The other countries that started with early reform by introducing significant changes of its electricity sector are Norway, Sweden, UK, parts of United States, parts of Canada and Australia. Since then the market evolved at different rate and in different direction in each country and region [1], [2]. The driving force behind restructuring of electricity sector is to promote competitive generation and trade of electricity removing the monopoly of vertically owned utility. Deregulation of electricity supply industry has now become a global trend as a method of best practice adopted after the success of markets in pioneering countries. Deregulations in developing countries are still at its infancy stage and it is mainly driven as a part of government's macro-economic policy to encourage privatizations and investment in generation and distribution sector after some form of economic crisis. Since with the increasing power demands, they need loans to invest in Generation and transmission capacities and have to restructure their power sectors under requirements of international financial agencies. The deregulation is also initiated as an effort for effective and efficient sharing of resources in the country or between the countries in the region.

The first step in deregulation process is separating the generation, transmission and distribution. Then, competitiveness is introduced in generation and distribution activities. The transmission system is still kept as a monopoly because of economic and security issues. Public authorities have a role to regulate the Transmissions system opens to all parties. Deregulation helps bring down the cost of electricity and system losses and provides wider choice to customer by removing monopolistic structure. Deregulation will encourage private investor in the generation and distribution sector. The development of private sector is crucial for any socio-economic development of the country. It will also ease the government's financial burden of investing in development of power sector [3]

In order to fully reap the advantage of competitive market, it calls in for establishment of suitable market environment. It requires privatization of generation and distribution sector, establishment of proper regulatory bodies, Independent System Operator (ISO), Transmission System Operator (TSO) which will ensure reliable transmission network and give unbiased open access to all the participants in the market. The other participants in the competitive market are Generating companies (Gencos) and Independent Power Producer (IPP) which will own a single plant or portfolio of plant with different technology, Distribution companies (DisCo), Retailer, Market Operator (MO) and finally small and large consumer. There is different market structure adopted in different countries. The market structure successful in one country can prove failure in another country. So it is very important to choose the type of market suitable for particular country or region and it will be influenced by various factors governing the electricity market.

1.2. Motivations of the work

The motivation for carrying out this work is that the competitive market structure is non-existing in Bhutan at present. The electricity supply in Bhutan is still a monopoly in-spite of restructuring effort carried out by the government with unbundling of generation and transmission system from otherwise government owned vertically integrated utility. Bhutanese in general feel that the price of electricity is high given the fact that almost 99% of the power is generated using cheap hydroelectric power plants. Bhutan government is also interested to bring in IPPs participation to invest in hydroelectric project and introduce competitive electricity market in future. The fact that Bhutan exports 70% of its power produced to India and have huge potential to participate in electricity trade with neighboring countries was extra impetus to carrying out this thesis. It would be interesting to see how competitive market would affect the Bhutan Electricity Industry positively on whole.

1.3. Objective of the thesis

The main aim of this thesis is to do preliminary studies and develop a competitive Day-Ahead electricity market model in Bhutan suitable for deregulated environment by achieving the following objectives:

- Comprehensive literature review of competitive electricity market structure and practice adopted in various countries in the world.
- Review of Bhutan Power Sector and its deregulation status.
- Build Bhutan Power system with less than 50 buses in Power World Simulator and develop a market model by dividing buses into four generation areas.
- Simulate the model for OPF-based market using LP based OPF Power World simulator and observe and analyze the LMP in 24 hours Spot Market under different cases with social welfare maximization as objective function.
- Develop Uniform Price Market and to build bidding block for generation and load for Day-Ahead Spot market and analyze the market price with Social welfare maximization as objective function.
- Compare the market price, system losses and generation cost of the existing system with proposed competitive market model.
- Propose a recommendation for the most suitable market structure for the existing Bhutan Power system.

1.4. Outline of the Thesis

This thesis is organized as follows:

Chapter 1 gives the background and main motivation for carrying out this thesis and what objectives it hopes to achieve. It also provides the scope and limitation of the work.

Chapter 2 is devoted towards understanding the process of deregulation and competitive market model being adopted in various countries in the world. Lots of various literature reviews had been done for it.

Chapter 3 gives the background of Bhutan's Power Sector and its status of deregulation. It provides information about various stages of restructuring of Power Sector. It also highlights the importance of hydroelectric power plant in Bhutan. The internal and export tariff of electricity is also discussed.

Chapter 4 is the core of this thesis work. The competitive market model of Bhutan is modeled and simulated using the Power World Simulator. The OPF based and Uniform Price based Market is experimented on the model to get the market price. The bidding curve for supply and demand side is also constructed for the Day-Ahead Market for both in both the cases. The result from the model is compared with the existing system in Bhutan and suitable market model is recommended.

Chapter 5 discusses the important technical consideration that have to be made for successful and smooth operation of any competitive electricity market. Deregulation will bring in many problems beside its benefits, it is important to prepare contingency plan like congestion management and ancillary service market.

Chapter 6 is conclusion and it summarizes the whole content of thesis and stress the advantage of the proposed competitive electricity model compared to existing system. The thesis is concluded by keeping the options open for further improvement of the model and some suggestions for future work in the same area.

1.5. Scope and Limitations

The objective of this study is to show that competitive electricity market in Bhutan will bring positive effect compared to existing system in terms of price of electricity of the end consumer, total cost of generation and system losses by simulating the proposed electricity model in Power World simulator. The various contingency cases are also studied in both the market.

Some of the buses in the Bhutan power system had been lumped to keep it below 50. So the effect of error from it is not considered. The power system model is built in Power World with data made available from Bhutan and papers available online. Attempt had been made to build the model as close to real network as possible but there is always some margin for error because in some cases, valid assumption had to be made in absence of data. The hydro projects under construction and the transmission line expansion being carried out at present is not considered in the proposed model.

2. CHAPTER 2: ELECTRICITY MARKET MODELS IN THE WORLD

This Chapter gives an overview of how deregulation is being implemented and the type of market structure being practiced in different parts of world.

4.1. Asian Countries

2.1.1. Japan

Real deregulation of Japan electricity market started in 1995 by allowing Independent Power producer (IPP) sign in long term contract with vertical integrated unit. The energy market before that was a vertically integrated structure company- Electric Power Development Companies (EPDC) which had monopoly of regional power supplies and its stock holder was mainly government. EPDC had its own transmission network too. The vertically integrated system incumbents are still sustained but the governing institution saw several restructuring in Japanese liberalized electricity market which makes it different from Europe and USA restructuring model. The deregulation started by allowing Independent Power producer (IPP) sign in long term contract with vertical integrated unit. The evolution of Japanese market is as given in Figure 2.1.[4]

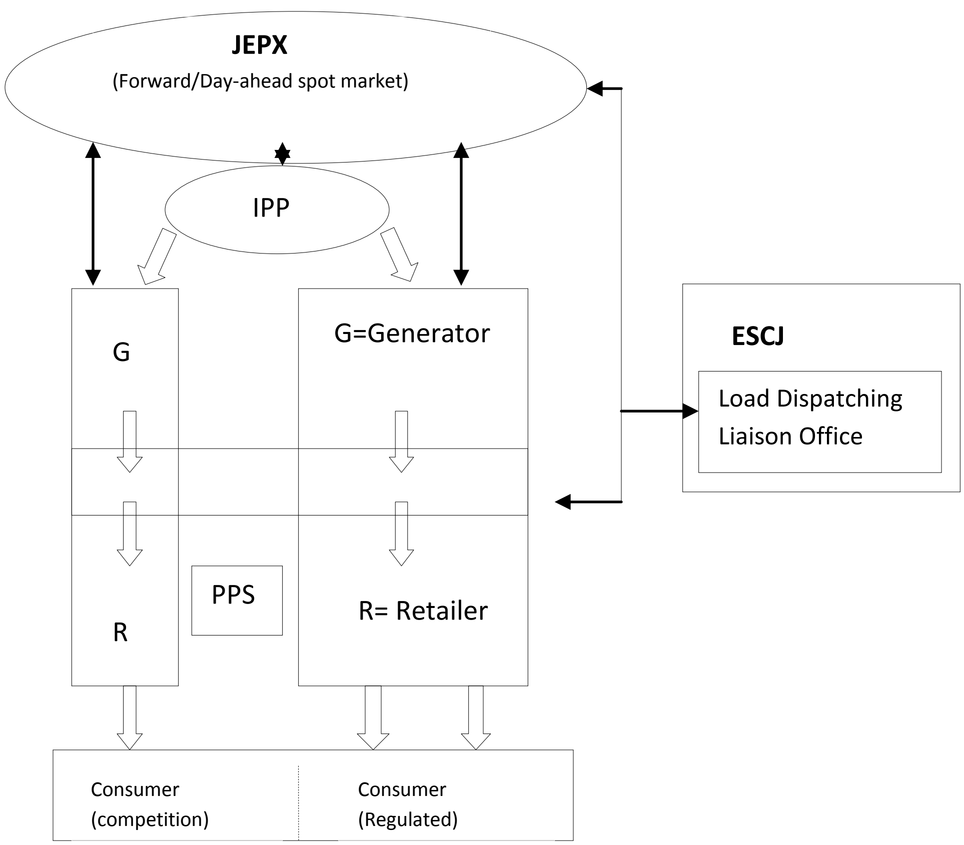


Figure 2.1 Electricity Market Evolution in Japan[5].

The deregulation in Japan was mainly driven due to relatively high price of electricity, necessity to increase distribution such as co-generation or auto producer, create competitive market condition including retail wheeling and for increased reliability and also due to global trend of electricity market liberalization. The nature of restructuring of energy market in Japan is influenced by its typical characteristics like high population density and energy consumption, frequent threat of natural calamities like earthquakes and typhoon, strict emission controlled generation plant. Japan attributed its high cost of electricity due to need for relatively high reliability of power supplies in comparison to European countries. The cost analysis of Transmission & Distribution (T &D) conducted in comparison with USA was found to be 5 times higher in Japan[4] The comparison of electricity price of Japan with OECD countries is given in Table 2.1.

Table 2.1 End-user electricity prices of five OECD countries in 1995 and 2003.

	Total Price(US$/unit)				Total Price(US$/unit)(using PPP)			
	1995		2003		1995		2003	
	Industry	Household	Industry	Household	Industry	Household	Industry	Household
USA	0.05	0.08	0.05	0.09	0.05	0.08	0.05	0.09
UK	0.07	0.13	0.05	0.12	0.07	0.13	0.05	0.11
France	0.06	0.17	0.04	0.13	0.05	0.13	0.04	0.12
Germany	0.10	0.20	NA	NA	0.07	0.14	NA	NA
Japan	0.19	0.27	0.12	0.19	**0.10**	**0.14**	**0.10**	**0.15**

The current Japan's electricity market consist of five entities- general electric utilities (integrated utilities), wholesale electric utilities, wholesale suppliers, special electric utilities and specified-sale electric suppliers. The government desires PPS to invest in their own generation and use JPEX in the long run. In-order to avoid imbalance payment for PPS, a new hour-ahead market is introduced. In April 2007, the Electricity Industry committee, the Advisory committee for Natural resources and Energy of METI discussed the possibilities of full liberalization of retail market by 2013 by also including low voltage (100V/200 V) customer[7], [12].

Deregulation in Japan resulted in:

- Increased in efforts to reduce transmission cost while maintaining appropriate reliability.
- Decrease in price of electricity for residential, commercial and industrial consumer.
- Increase in number and share of PPS in retail electricity market.
- Increased competition leading to reducing the range of electricity price in different areas.
- Investment in supply and quality has decreased by 1/4th and the investment made is on recovery trend.

- Increased to response in peak demand.
- Individual institutional reform resulted in elimination of pancake rates, establishment of neutral agency and power exchange.

There is at present physical restriction for trading power between Eastern Region and Western Region in Japan because ESI currently operates at two distinct systems with different frequencies of 50 HZ and 60 Hz respectively. A frequency convertor is used to provide an interconnection between two regions.

2.1.2. South-Korea

Since 1961, Korea Electricity Supply Industries remained vertically integrated structure monopolized completely by Korean Electric Power Corporation (KEPCO) in all generation, transmission and distribution. But in January 1991, the basic plan for restructuring of electric power industries began. It leads to the unbundling of KEPCO into six generating companies and establishment of Korea Power Exchange (KPX) in April 2, 2001-System& Market operator and Korea Electricity Commission (KOREC) in April 27, 2001-regulator. In 2001, Cost Based Pool (CPB) in generation market was introduced. It is based on the variable cost of generators evaluated by KPX. It had two separate markets-Base Load Market for coal and nuclear power plants and general market for all generators except base load generators. CPB is followed by Price Based pool (PBP)-producer offer will determine the market clearing price and Two- way Bidding Pool (TWBP) where prices will be determined by bids and offers from generation companies, suppliers, wholesale consumers[8]-[11]. The Market flow chart for CBP is shown in Figure 2.2.

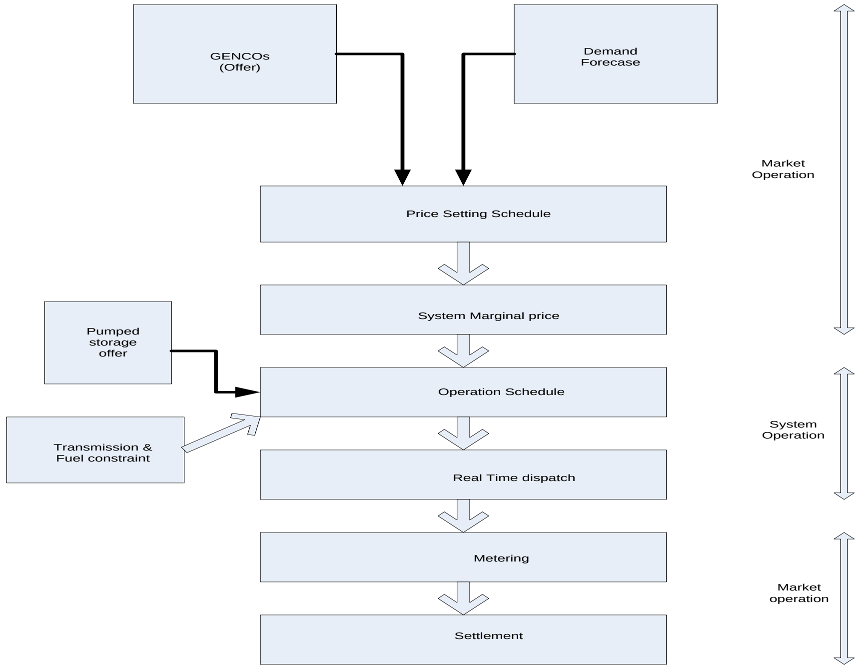


Figure 2.2 Market operation Flow Chart [10].

The need for deregulation in Korea was mainly motivated by the global trends towards deregulation of electricity market; need to increase the efficiency and competitiveness of electric supply industries, Economic crisis in 1997 which called upon the government for fundamental reform in industrial structure to improve national productivity, rapid increase in electricity demand and consumption and lastly to bring down the price of electricity at an average international level thereby increasing the consumer benefit [9].

The deregulation bought the following positive changes in Korean Electricity market:

- Improvement in efficiency of generation through competitive CBP market.
- Increase in net profit of generation by 42% and decrease of generation cost by 6%.
- Improvement of debt ratio (4.4% since spin off) and labor productivity went up by 23%.

2.1.3. Thailand

The Electricity Generating Authority of Thailand (EGAT) was established in 1969 was solely owned by government which was later corporatized by National Energy policy Office (NEPO). The deregulation in Thailand was manly driven by the economic crisis of 1997 which required change in Thai macro- economic policy to privatize and restructure its economy as per IMF condition.

It was step towards formation of competitive market for GenCos to compete in the pool market as well as bilateral market with large customers and retailers. In Pool market, ISO has to choose the generator with least dispatch price along with Market Operator (MO) and Settlement Administrator (SA). The transmission network remains monopoly owned and maintained by separate operator (EGAT-T) and regulated by Independent Regulatory Body (IRB) to ensure open access and facilitate and reasonable tariff. Third party access is also introduced to enable power producer to sell directly to its customer through "wheeling" transaction (2001 to 2003). From 2003, competitive wholesale power pool was envisaged hence introducing retail competition. GenCos would dispatch in wholesale pool and one with the lowest bid for the period will be offered to sell the power. ISO is formed as government corporate and is responsible for economical and merit order dispatch, system security and financial settlement for bulk power purchase[12],[13]. The price based Pool market model is shown in Figure 2.3.

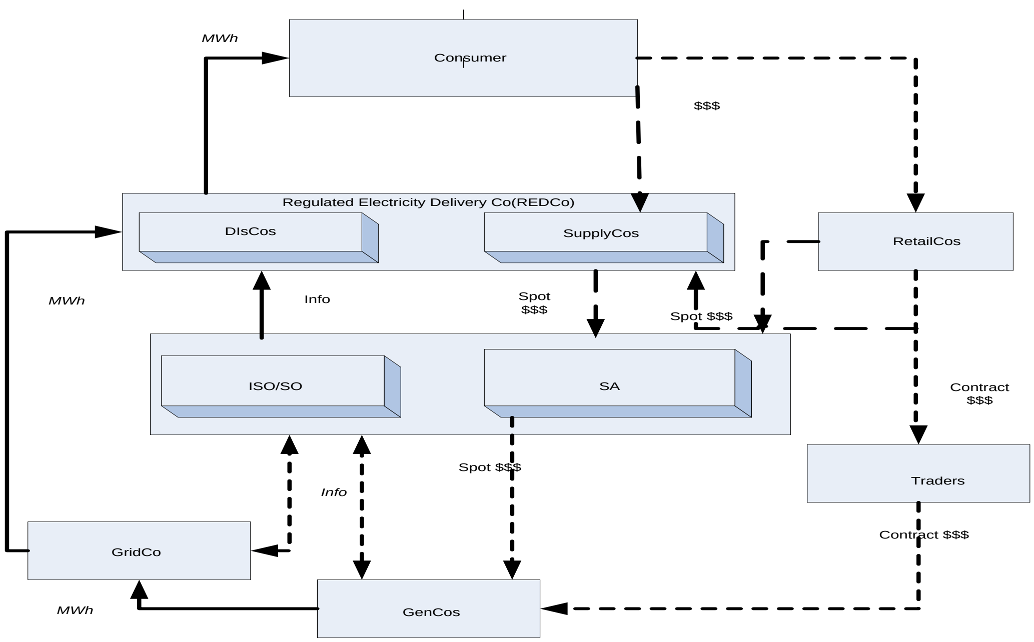


Figure 2.3 Price-based power-pool model[13].

2.1.4. India

The restructuring was started by inviting IPPs in its limited competitive market. In 1992, the generation and transmission were separated and Power Grid Corporation of India Limited (PGCIL) was entrusted with transmission network for its better co-ordination. The unbundling of generation, transmission and distribution at state level saw privatization of distribution in some states. In 1998, Central Transmission utility (CTU) at national level and State Transmission utilities (STUs) were formed.

Private sector can now invest in all the three areas of generation, transmission and distribution [7], [14], [15].

The Electricity Act, 2003 called on for restructuring of the electricity supply industry. The Act laid down for power trading and eventual creation of spot market, transition from state owned monopoly to liberalized and competitive market and optimum scheduling of generation and transmission among regional transmissions grid and others. The creation of wholesale market at bulk consumer and distributor level will enable them to freely buy power from generating companies, power pool and power exchange in the market as per their requirement as can be seen in Figure 2.4.The restructuring at state level enabled STU to run power pool based on cost-based (non bid) for regulated generating plants and IPPS within the state. The new power plant that comes into play after de-licensing period will be free to trade their power through spot market or through long or short term fixed contract with their bulk consumers/DisCos.

As for the system operator model, TSO (Transmission System Operator) as prevalent in Europe and other Asian countries is found suitable for India. It is because the main transmission company is government owned and will be effective in providing non-discriminatory open access and is solely responsible for planning and developing the transmission system which was found operationally and financially effective. ABT adopted by system operator for load dispatch function was found effective in maintaining nominal system voltage profile and frequency [14], [15].

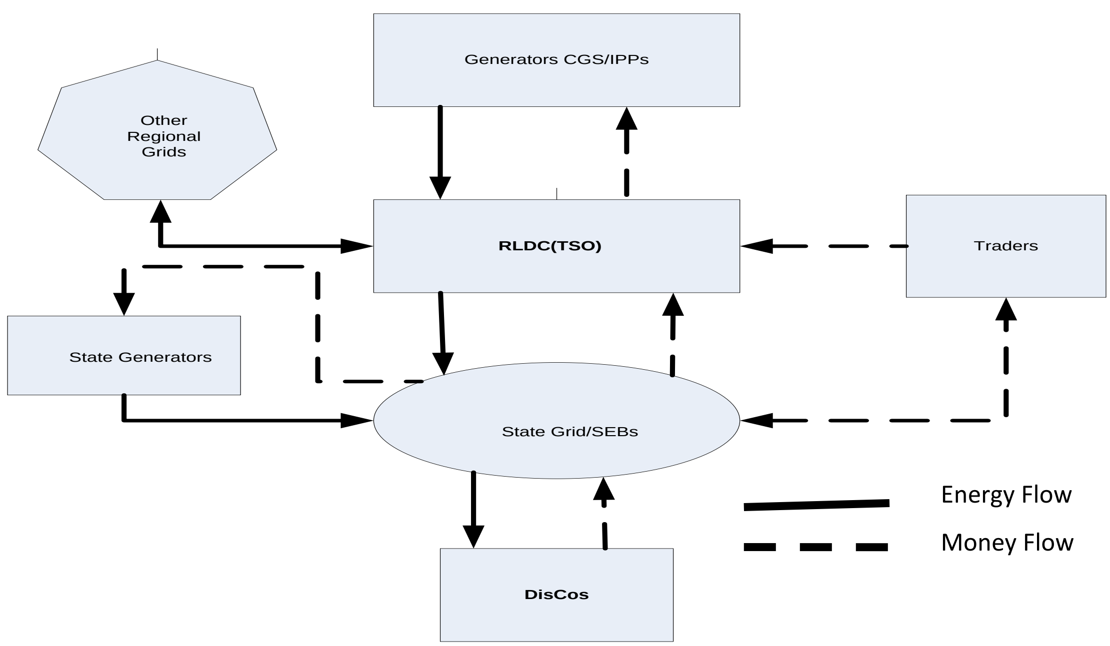


Figure 2.4 Current Indian Power Market Structure [15]

It is felt gainful experience from wholesale market should be used to form competitive market at retail level which they find bit immature for Indian Power industry at present [14], [15].

4.2. United States

The electrical utilities in US were predominantly owned by private investor called IOU unlike the vertically integrated structure in Europe and other parts of world. So it was less likely for those utilities to be taken under public ownership. In 1995, there were 195 IOUs with peak demand over 511,435 MW. These utilities delivered 72% of the energy at retail level and 42% at wholesale [2], **Error! Reference source not found.**.

The United States electric system is currently regulated by The Federal Energy Regulatory Commission (FERC) at different level. Beside price for electricity in wholesale market it also regulates service terms and conditions. There are also regulators at state level, local bodies like city council which besides setting reasonable rate for electricity also were responsible for planning for additional plant, reliability requirements, local retail services and the site for new transmission services.

The deregulation in USA is different from that of European countries due to the fact that the transmission network in USA did not have the common feature of single national grid. Instead it had electrically separated vertical integrated structure based on region [17].

The major market model in USA as related to ISO includes California, Pennsylvania-New Jersey-Maryland (PJM), Electric Reliability Council of Texas(ERCOT), New England ISO and Midwest ISO(MISO). We will look at California and PJM market model here.

2.2.1. California Market

Deregulation was introduced in 1990 to facilitate competitive market and to bring down cost of electricity to Californian at the same time ensuring system reliability. It is the first one to offer large scale retail choice and competitive generation market. The California market restructuring is different from the rest because it was proposed to address specific needs like meshed characteristics of network, frequent transmission congestion, variety of generation resources and implementation of bilateral contracts. Another major aspect was that the commitment of unit responsibility remained with owner and not the market

The three market model implemented were day-Ahead Market, Hour-Ahead market and real Time (balancing) Market. In these markets energy and ancillary services are also traded. In March, 1991, the CalPx introduced Block-Forward Contract to trade standardized monthly block contracts to help market participants especially large consumer to hedge against hourly price variation/price volatility. The contract period is now extended to 12 months. In September, 1999, the Block forward Market was extended outside California energy market place. Ancillary service includes spinning reserves, regulation, replacement reserves, regulation, reactive power and black start capability [17]-[25]. Interaction among different entities is shown in Figure 2.5:

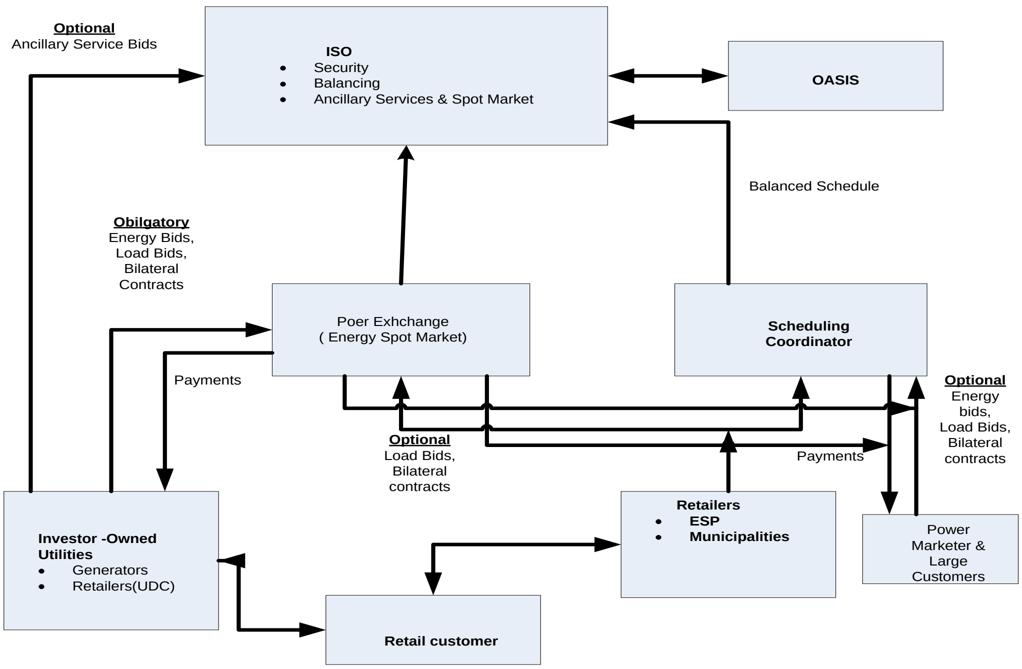


Figure 2.5 Interactions between California ISO and other Entities [24]

The California market underwent several changes after the California Power crisis in 2000 when the electricity price sky rocketed and almost all its IOUs went bankrupt. The crisis is attributed to various snags in energy market model for instances, reserve margin fell below 5% due to reduction in hydro power generation throughout the western USA, lack of real-time price signals to customer, over-reliance on spot market, increased cost of fuel and Nox emission cost, weak transmission capacity along its critical path and FERC's failure and inactions to intervene in exercise of market power for one year. These led to unrestrained ability to exercise market power by supplier in already tight supply-demand situation. The failure was not exactly a market model here but it was due to failure to implement a market structure that would safeguard against exercise of market power. It also lacked the proper policy and implementation of congestion management [17].

2.2.2. PJM market

PJM was created as Power Pool in 1927 by Public Service Electric & Gas, Philadelphia, Electric Company and Pennsylvania Power & Light in Pennsylvania and New Jersey. PJM filed with FERC to become an ISO in 1997 by including eight interconnected utility system and it began to evolve from there. The PJM is responsible for interconnection for operation in major parts of six states. It manages and operates the largest wholesale electricity marketing in the world with open access transmission and Financial Transmission Rights (FTRS). PJM is regulated by FERC .The responsibilities of PJM ISO operates the energy spot market, maintaining the reliability of the grid as authorized by FREC, transmission planning, unit commitment, operating real time market and settlement of billing and function. Transmission access is done through OASIS and LSEs were responsible for supplying retail customers. The transmission network were owned by many entities but operated by PJM and the service provided are Network Transmission Service(NTS) and Point -to -Point service.PJM includes all kinds of energy transaction market The day ahead market and energy spot market and real- time balancing market are operated by PJM. Locational Price Marginal Prices (LMPs) calculated on each bus are used by PJM to hedge congestion. PJM also operates two bilateral contracts, internal and external in which the two parties are within the PJM controlled area or other party is outside its area respectively. All the data exchange is done though ISO. PJM currently provides regulation and spinning through market based mechanism and it also provide for energy imbalance service through Real-Time Energy market and provides the remaining ancillary services on cost basis. PJM introduced a market for spinning reserve in december 2002 [22]-[27],[28].

4.3. Latin America

It is interesting to look into deregulation in Latin America. It is hydro-dominated market. The electricity sector regulation promoting market competition was first introduced in Chile in 1984 and it spread to other region. The restructuring in Argentina began in 1992, Bolivia and Colombia in 1994, Brazil in 1996 and Central American countries in 1997. Venezuela, Mexico and Ecuador have also started its restructuring its electricity market. The deregulation in these countries started with formation of "poolcos" .It was a centralized dispatch system and price of electricity was based on the audited cost of producing it. This new reform saw decrease in the price of electricity, elimination of market powers, increased private investment and improvement of power quality. But the droughts and unpredictability of water availability of hydro-dominated market in the region later caused high rate of investment resulting in decline of private investors and hence there was need to reform the pool system and to adopt the *laissez faire* model of perfect competition for power exchange. So the next step was regionalization of electricity systems. It leads to cross border interconnection and establishment of regional market. In 1997, Uruguay and Brazil was interconnected and Peru, Ecuador & Columbia in 2001 [1], [25], [26].

Brazil is hydro dominated characterized by large reservoirs capable of multi-year regulations. It has cascade arrangement spanning over several river basins. The hydro dominated system like Brazil present fairly low short term price volatility as its system reservoir can easily transfer energy from off-peak to peak hours. But during dry season, the energy price will increase sharply in spot market, the main driver in Brazil energy spot market is the overall reservoir system as it had negative co-relation. This negative co-relation results in economic benefit of selling energy in spot market less than expected. Rationing of electricity prices by the government during unfavorable hydrological situation was met with widespread oppositions from its consumers [26].

In Colombia, Losses were 22% high in 1994 before deregulation and were reduced to 17% in 2000. The deregulation in Chile electricity system appears to be successful shows the losses were reduced gradually from 20% to 7% after ten years after deregulation.

4.4. European Countries

2.4.1. Nordic countries

Nordpool was the first international power exchange in the world which facilitated electricity trading in Nordic region. Nordic Power Exchange is to provide market place for trading energy in Nordic countries (Norway, Sweden, Finland & Denmark). Its physical market accounts for over 60 per cent of the total value of the Nordic region's power consumption. With liberalization in Sweden and Finland and early market reform in Norway, an internal free trade energy market was constituted. The Nordpool plays a significant role in the Nordic countries because these countries have the highest per capital electricity consumption in the world. Though it has small population comparatively but is characterized by heavy industries based on abundant supply of cheap electricity. Since Nordic countries are cheap producer of electricity, it is competent in the European free- trade context [30]-[34].

Deregulation in Norway started in June 1990 as per its Energy Act and the market operation started in May, 1992. The restructuring started by creation of nationally owned company Statnett as transmission owner, market operator and ISO after the ownership was transferred from public utility, Statkraft. Similarly the deregulation in Sweden started in October, 1996 and joined the Norwegian market in January, 1996. The transmission network ownership and ISO was transferred from national utility Vattenfall to Svenska Kraftnat. Nord Pool was the formed with equal ownership of Statnett and Svenska Kraftnat which took over the operation spot and future market in both the countries. The deregulation in Sweden eliminated otherwise the market power that would have been exercised by the Sweden-only market Vattenfall [30]-[34].

The deregulation in Finland started in June, 1995 when its new Electricity Market Act came into force. Finland joined common Nord Pool market in 1999. The restructuring of Danish Electricity market took place after the Electricity Supply Act was passed by Danish Parliament in 1996 and notified by EU commission at end of 1997 by providing an open access of grid to large customers and distribution companies. Western Denmark (Jutland) was integrated to Nordic market in July, 1999 followed by Eastern Denmark (Zealand) in 2000 [30]-[32].

The generation source in Nordic countries is mixed. Norway has almost 100 % Hydro, Sweden and Finland have a mix of Hydro, Nuclear and Thermal plants and Denmark has almost 100 % Thermal Plant. There had been rapid growth of wind power generation in all the areas. It is expected that wind energy will penetrate the Nordic market bringing down cost of electricity and reducing the risk of price volatility in the competitive market. The Nordic countries are technically interconnected to each through HVDC lines to form one single synchronized power system. The Nordic countries have one common single market operator- Nord Pool and five separate system operator(TSO) in each namely Statnett (Norway), Svenska Kraftnat(Sweden), FindGrid(Finland), Elkraft System (Eastern Denmark) and Eltra (Western Denmark). The system operators are regulated separately in each area. Nordpool was formed for better utilization of its available resources, improve competition amongst its producers, bring down cost of electric energy and reduce emission through sustainable energy development [30]-[34].

Market structure in Nord Pool

- Financial market trading including different financial contracts like Forward and Future contracts for risk management and speculation. The future market in Nord Pool market saw steady growth which presently makes up 16% of energy consumed in the Nord Pool area. The future market involves purchase of weekly base or peak load contracts thereby facilitating generators and loads to hedge price volatility risk. It was initially settled by physical delivery of electric energy but settlement became financial against the spot market weekly average price in October 1995.
- Wholesale Day-Ahead Power market (Nord Pool spot) for hourly contracts for physical delivery of power the next day. The spot market accepted bid for 24 hours of each day until noon 12.00 and settled for each day by 15.00 of the preceding day. Bids are in the form of linear segment price versus quantity curves for both generators and loads. These curves are crossed to obtain a system price for both buyer and sellers. TSOs were required to provide the transmission line trading capacity before price settlement begins. These transmission bottle necks would result in different price on different day and areas. The spot market participation is not mandatory.

- An intra-day power trading for continuous one hour trading of one hour price contract before delivery called Elbas market. This facilitates the market participants to trade changes from their planned supply and demand in the day-ahead market.
- Real time market which is market for regulating power and is flexible. Here the producer and consumers submits their bids for upward and downward regulation with activation time of utmost 15 minutes and should bid one hour before delivery. The Nordic TSO monitors the bid and chooses the cheap regulating bids.
- Bilateral market: The bilateral contract can be between the parties within each country or it can be between two countries in Nordic market. In first case, it can contract with one point connection of sale or two different point of connection of sale. Whereas in the later kind, the contracts can be 5-kwh arrangement or contract arrangement to hedge the price against spot market between buyer and seller. It means if spot price rises above the contractual price, the sellers pay the difference between the two prices and vice versa.
- Ancillary Service market like spinning reserve which is operated separately by TSO in each country.
- Congestion management- Two different models are used to handle the congestion. Norway uses Area Price Model also called Market Splitting leading to different area prices. Sweden manages its congestion by Counter-trade (Buy-back) method. TSO in Sweden and Finland pay for the download regulation in surplus zone and the upward regulation in deficit zone .

2.4.2. England and Wales

UK is the pioneer in electric liberalization market which later set an example for other European countries electricity market liberalization policy. The Electricity Act in 1989 called the transition of electric industry from government owned to private investor to encourage competition, improve efficiency, more involvement of employee and to reduce the price to customer. The Act came into force after drawing criticism from Public and political forces for government owned monopoly of electric industry. The National and Power Gen companies were sold to new participants and new generators entered the market. These new structures lead to formation of Pool as a means to trade electricity. Every generator submit its bid offer in day-ahead market then the grid operator forecasts the demand and uses centrally dispatched generating units to meet the demand [33].

Ancillary Service except spinning reserve, are contracted by grid operator and are recovered through uplift charges on purchase while spinning reserve is paid through market and its uplift charge is levied on purchaser.

2.4.3. Other European Countries (EU)

The EU with its 15 member nation (in 2000) has worked towards economic corporation and towards liberalization of electricity market. The European Union's Electricity Directive adopted by the Council of Ministers in December 1996 laid down the common rules for generation, transmission and distribution in internal electricity market. It also set the minimum timetable for member nation electricity market opening. The threshold for market liberalization was set at three different levels- 26.5% by February 1999, market opening of 28% by February 2000 and required minimum market opening level of 33% by February 2003. The members were free to choose as how to start with the electric market deregulation or proceed with liberalization beyond the threshold level. The EU countries like England, Sweden, Finland & Germany and non EU country like Norway have already liberated their electricity market by 100%. The EU directive required the member nation to come up with the national laws and regulation to facilitate the electricity market complying with the directive. The directive introduced with the full competition in generation sector [30].

The electric power system within EU nations is well connected. The Power systems of Austria, Belgium, France, Germany, Greece, Italy, Luxembourg, The Netherlands, Portugal and Spain are inter-connected. While the power system of United Kingdom and Ireland is interconnected with France. The power system of Germany is directly connected with Nordic Power System too. The most widely used transmission levels are 380 kV and 220 kV. The biggest electricity producers in EU are United Kingdom, Germany and France [30], [34].

The market liberalization saw comparative decrease in electricity price in many countries while it increased in some countries. There is also growing trend towards electricity production and demand. With the EU directive for CO_2 emission reduction and target for doubling of renewable energy resources by 2020, the production pattern will influence with electricity price. The countries which depend on hydropower will be able to produce cheaper energy than other nation that depends on combustible fuel [30]-[35].

On the whole, the electricity price in EU fell on average by 6% between 1996 and 1999 as a result of deregulation [34].

2.4.4. Summary

The summary of the markets studies is given in Table 2.2.

Table 2.2 Summary of type of market in different countries.

Countries	When market opened?	Type of Markets	Time-frame	Bidding Block	Objectives of the Market	Ancillary services	Network Included?
Japan	1995	Pool Market	24 Hours	Hourly	Minimization of consumer payment and maximization of system security.	VAR as an ancillary service for reactive power compensation. And 15 % bulk storage from Pumped hydro.	No
South Korea	April 2, 2001 August,2003	Cost Based Pool(CBP) Market. Wholesale Market	24 Hours	Hourly	Maximisation of social Welfare	NA	No
Thailand	2002	Pool Market				NA	No
India	2003	Cost Based Pool (CBP) Market and not bid based.			Minimization of consumer payment	NA	No
Nordpool (Sweden, Norway, Finland, Denmark and some part of Germany)	Norway in June 1990, Sweden in October 1996, Finland in June 1995 and Denmark in 1996.	Pool Market is not mandatory. Bilateral market in their respective country or between two countries in Sweden and Norway.	24 Hours	Hourly	Maximization of Social Welfare in Double Auction Pool.	In Sweden primary regulation is through bilateral contracts & secondary through the balance service. Black start capability and system control is also through bilateral contract, Spinning Reserve.	No
France	2000	Bilateral Market	4 or more days ahead	Not hourly	Maximization of social welfare and social cohesion.	Spinning reserve, Voltage control, Frequency Regulation, Grid loss compensation, Emergency Control, Spinning Reserve.	No
UK	1989	Pool Market	24 Hours	Half-hour	Minimization of consumer payment and maximization of social Welfare in single auction pool	Frequency regulation, Voltage control, Standing reserve and Black Start Capacity.	No
USA(PJM Market)	2000	LMP based Pool Market	24 Hours	Hourly	Minimize total production cost subject to certain constraints.	Synchronized reserve, regulation & Black- start service.	Yes
Latin America	Chile in 1984, Argentina in 1992, Bolivia and Colombia in 1994, Brazil in 1996 and other Central American countries in 1997.	Pool Market	24 Hours	Hourly	Minimization of consumer payment and maximization of social Welfare	Spinning reserve, Frequency regulation	No
Australia(NEMCO)	Australia	Pool Market		Half-Hour		All the Ancillary service are recognized and cpmensated except sheduling. Disptach & system coontrol. VAR from sychronous condender.	No

3. CHAPTER 3: POWER SECTOR DEREGULATION PLAN IN BHUTAN

Bhutan Power sector plays a vital role in small economy like Bhutan. Hydroelectricity is major contributor towards total revenue in the country. This chapter gives an overview of hydroelectric power plants in Bhutan and its importance as a backbone for social-economic development of the country. The deregulation status of Bhutan Power sector and electricity tariff is also discussed.

3.1. Overview of hydroelectric plant in Bhutan

The Kingdom of Bhutan is a land-locked country located on the southern slope of eastern Himalayas between China in the North and India in East, West and South as shown in Figure 3.1. The country due to its rugged geographic terrain is endowed with perennial flow of rivers and rich vegetative cover of approximately 64.35 %. The energy source in the country is almost 100 % hydro like in Norway. Bhutan has huge hydro power potential which is estimated to be about 30,000 MW with a technical feasibility of 23,760 MW. At present only 4.96 % of the potential had been harnessed. The total installed capacity of hydro power in Bhutan at present is 1488.66 MW. The domestic consumption is approximately 250 MW and rests are all exported to India through bilateral contract between two countries. The hydro power sector is the main contributor of Gross Domestic Product in Bhutan with contribution of 45 % towards total revenue (2006/2007). The government aims to increase the generation capacity to at least 10,000 MW by 2020 by building many more hydro power plants. At present the construction of Puna Tsang Chu Hydro project Stage-I (1170 MW) is going on and Dagachu hydro project (114 MW) is in it's tendering stage. Many such big hydro projects are in pipeline. Since the government saw the need to increase use of its sustainable resources without destroying the balance of rich biological diversity and eco system, it was made mandatory to maintain minimum 60 % forest cover perpetually. Sustainable development is one of the pillars for Bhutan's development philosophy of Gross National Happiness [36]-[40].

Figure 3.1 Location of Bhutan with respect to its neighboring countries[38] .

3.1.1. Advantage and Disadvantage

Hydro power plant has no or almost negligible marginal cost. It has the advantage of producing and adjusting the energy production at will if it has substantial reservoir. The hindsight is the amount of energy available determined by rain or snow falls in their hydrological basin.

The run-off river scheme hydropower in Bhutan is attractive from cost and environmental aspect. But problem with such scheme is that with no dam or reservoir to store water, the power plant relies exclusively on the availability of water in the river which is seasonal. These will lead to diversion of excess water during summer (under utilization) and almost no power generation during draught condition.

3.1.2. Restructuring of Power Sector

Until July 2001, the power sector remained under direct control of Department of Power(DOP) which was part of Ministry of Trade and Industry. It was fully responsible for domestic energy supply within Bhutan. Both the commercial operation and regulation framework, policy making decision were bundled under single entity of DOP. The revenue earned from sale of electricity were directly included in the government budget and its operating head was also funded by the government. There was little or no incentive as such to relate the domestic tariff to the economic cost of supply. The government felt the need to increase the efficiency of power sector. The restructuring plan for power industry was initiated between government and Asian Development Bank (ADB). To support the restructuring effort ADB provided with three Technical Assistance (TA) grants amounting to $1.5 million from 1995 to 1999. The first step towards restructuring of electric industry took place with passing of Bhutan Electricity Act in 2001. The driving forces behind restructuring were:

1. Institutionalization and corporatization of utility function under DOP and make it more commercially viable.
2. Improve efficient use of energy by revising its domestic tariff and economic cost of supply
3. Encourage private participation in power sector through Independent Power producers (IPPs) and Joint ventures.
4. Electricity for all by 2020 including rural electrification plans.
5. To introduce reform in energy sector to make it more efficient, vibrant and cost effective.
6. To develop national transmission grid in Bhutan
7. Develop National Load Dispatch Centre (NLDC) in Bhutan
8. Better Management of Information system in Power Sector.

In July 2002, DOP was restructured into Department of Energy (DOE), Bhutan Electricity Authority (BEA) and utility company the BPC (Bhutan Power Corporation) and Druk Green Power Corporation (DGPC) constituting of GenCos was formed in 2008 as shown in Figure 3.2. DOE is central government agency and is responsible for formulation of policies, plans and guidelines for energy sector. It also advises government on all technical issues related to energy development strategy, implementation, monitoring and evaluation. It also gives techno-economic and budget clearance to projects related to energy. It also does feasibility studies related to hydro project development and Detailed Project report (DPR) for its sustainable development. DOE also functions as RGoB/donor/lender fund coordination related to energy/power sector project [40]-[41].

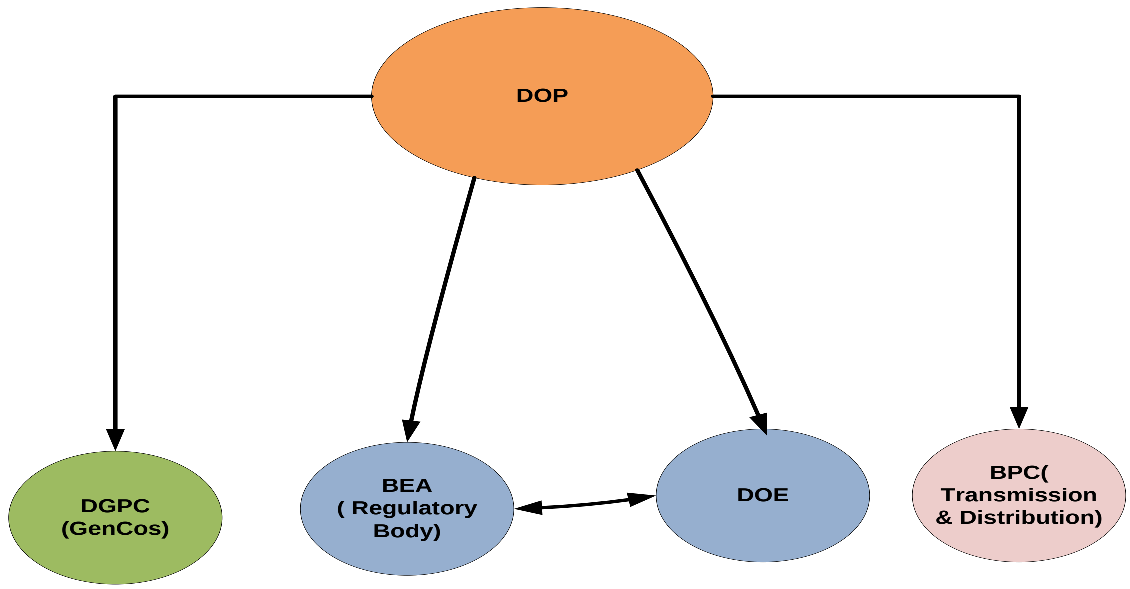


Figure 3.2 Unbundling of Erstwhile Department of Power (DOP)

BEA was formed as an autonomous agency under the Bhutan Electricity Act, 2001 passed by National Assembly during its 79th session to regulate the electricity supply industry. It also worked closely with Norwegian Electricity Regulator, Norwegian Development Assistant Division (NORAD) to develop rules and regulation to under pin its operation. It has the following responsibilities.

- Electric tariff development, regulation and approval.
- Setting of technical standards and codes for safety and performance standard of the electricity sector.
- Licensing and monitoring function.
- Settlement of disputes related to Power Sectors.
- BEA regulates the hydro power generation licensees, Transmission & Distribution Licensees and system operators. It will also regulate all the participants in the electricity sector in the future.

Bhutan Power Corporation (BPC) was formed and corporatized in 2001 during restructuring as a public utility company with a mandate for transmission, distribution and supply of electricity throughout the country. It also provides transmission access to generating companies for domestic supply as well as for export. It is also responsible for ensuring reliable, adequate and affordable electricity to all Bhutanese citizens. BPC was corporatized following the deregulation of electricity market taking place all around the globe and as a step towards accepting the best practice. It is also in line for future plans of privatization of power sector with less intervention from government except in proper policy planning of the sector. The corporatization also helped people have clearer idea of the cost of supply and subsidy and also improved efficiency in operation of electric utility business which is more suitable for customer. BPC earns more than half the revenue from wheeling charges being paid by hydro power corporation. The power infrastructure under BPC is shown in Figure 3.3.

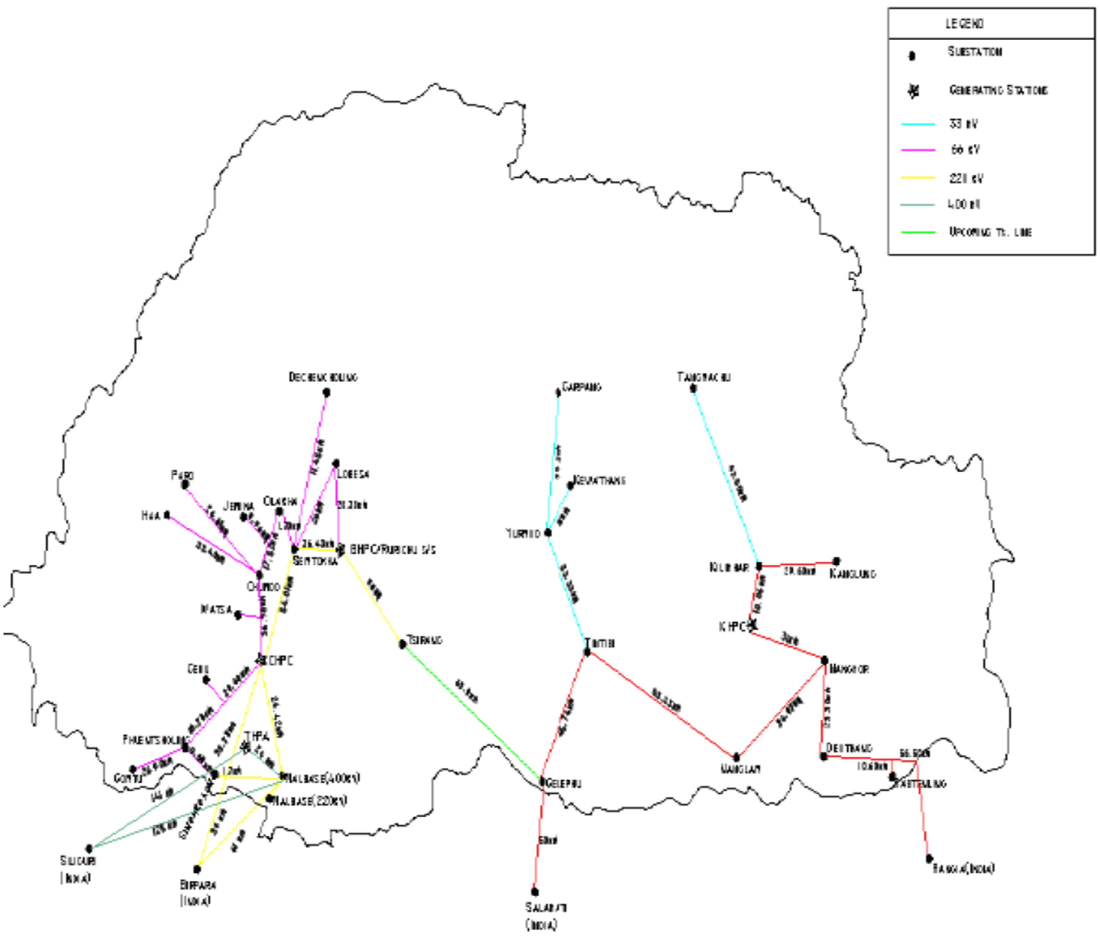


Figure 3.3 Power Infrastructure of Bhutan[42].

Druk Green Power Corporation (DGPC) was formed on 1st January, 2008. This is first step towards separation of generation companies from the being government owned corporation. The corporation was constituted to operate and maintain the generating plants separately. The generation companies like Basochu Hydro Project Corporation (BHPC), Kurichu Hydroelectric Project Corporation (KHPC) and Chhukha Hydroelectric Project Corporation (CHPC) came under the single entity with formation of DGPC representing Royal Government of Bhutan (RGOB). Tala Hydroelectric project Authority (1020 MW) is also corporatized and merged with DGPC recently. DGPC is set to further expand and grow as more hydro project will be integrated with it in future. The driving force behind this formation is to share the scarce resources more effectively and efficiently. DGPC will be responsible for implementing the RGOB's policy of accelerated hydropower development and other renewable resource like wind, solar and bio- gas to provide energy security in the country. It will be also responsible for building capacity in hydro power development and management. DGPC will help usher in more IPP participation (from both within the country and across the border) and Foreign Direct Investment (FDI) to harness the hydro-electric potential which would be very crucial to increase the total capacity beyond 10,000 MW [40]-[42] as given in Table 3.1.

Table 3.1 Status of Hydropower development in Bhutan[41]

Hydro Plant	Capacity(MW)	Remarks
Chukha	336	Commissioned
Kuricchu	60	Commissioned
Basochu I	24	Commissioned
Basochu II	40	Commissioned
Tala	1020	Commissioned
Mini/Micro	8.062	Commissioned
Total	**1488.068**	**Present Total Installed Capacity**
Punatsang chhu-I	1200	Under Construction (Inter-Govt.)
Mangdechu	720	Tendering Stage (Inter-Govt.)
Punatsangchhu -II	1000	Inter-Govt.(to be completed by 2020)
Chamkharchhu	1670	Joint venture(to be completed by 2020)
Sunkosh Reservoir	4000	Inter-Govt.(to be completed by 2020)
Kholongchhu	486	Joint venture(to be completed by 2020)
Wangchu Reservoir	900	Joint venture(to be completed by 2020)
Amochu Reservoir	620	Inter-Govt.(to be completed by 2020)
Kuri Gangri	1800	Inter-Govt.(to be completed by 2020)
Bunakha Resevoir	180	Joint venture(to be completed by 2020)
Total	**11,576**	**10,000 MW by 2020**
Inter-Govt. project will be between GOI & RGOB with 40% grant and 60% Loan from GOI		
Joint venture - Public sector from Bhutan and India will participate.		

3.2. Energy trading scenario

The domestic consumption is only about 30 % and rest are all exported to India as per the bilateral contract signed between India and Bhutan. The energy consuming sectors in the country can be divided into Residential Sector, Agriculture Sector, Industrial Sector, Commercial and Industrial Sector and Transport Sector. The Bhutan Power system network consists of eastern and western grid covering thirteen Dzongkhags. Bhutan is well connected to North- East Indian grid through six connecting points.

3.2.1. Export/Import Tariff

Most of the energy is sold to India through PPA signed between RGOB & GOI. The export/import wholesale rate for different generation companies is as given in the Table 3.2.

Table 3.2 Export tariff [46].

GenCos	Whole sale rate (US $/kWh)
CHPC	0.0415
THPA	0.037
KHPC	0.037

1 US$ =Nu. 48.198

As per the MOU signed between CHPC, BHPC and BPC, the allocation of power of power for domestic consumption from generating station shall be BHPC first followed by THPA and then CHPC. The wheeling charge is paid to BPC by the GenCos for export of power to India at the rate of 0.0026 US $/ unit. While Bhutan import power for residential load during winter from India at rate of export charges plus wheeling charges in India. It cuts down the supply of power to energy intensive industries during winter.

3.2.2. Internal Electricity Tariff

The electricity tariff in Bhutan is usually regulated so as encompass “Cost plus Rate of Return”. The tariff can be split into following cost structure:

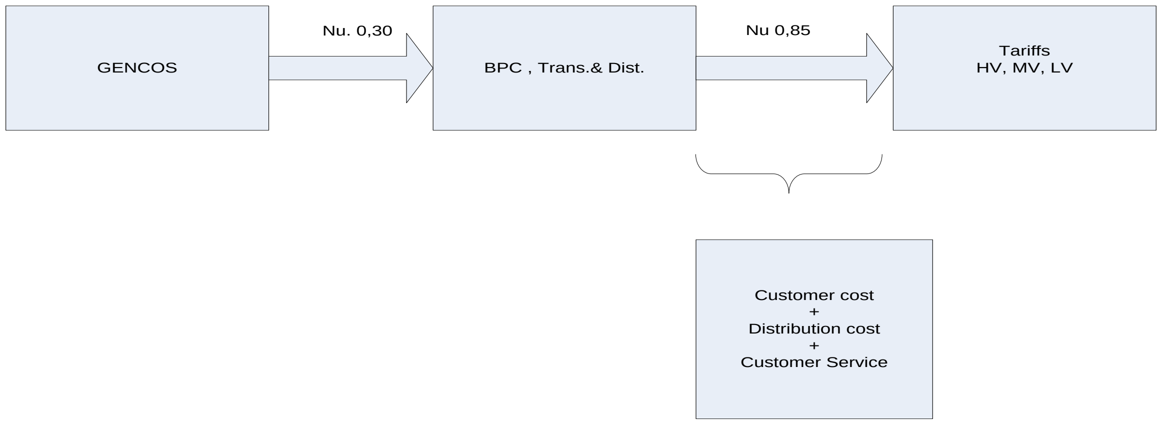


Figure 3.4 Cost structure of the tariff[37].

3.2.2.1. Energy transaction from GenCos to BPC and GenCo to GenCo

The prevailing royalty tariff valid for 15% energy of Ex-power plant generation sold to BPC is as given below:

Table 3.3 Rate of Power sale by GenCos to TransCo[46]

Whole sale rate of CHPC energy sold to BPC	US $/per unit
Wholesale rate of THPA sold to BPC	0.006
Wholesale rate of KHPC sold to BPC	0.006
Wholesale rate of BHPC sold to CHPC	0.025

The tariff for energy sold to BPC exceeding 15% of the generation is Nu. 1.25 per Unit.

3.2.2.2. Energy tariff for sale of energy by BPC to end consumer

The tariff is different for different voltage level. The electricity tariff revised and approved by BEA, Royal Government of Bhutan w.e.f July 1, 2007 to June 30, 2010 **Error! Reference source not found.**is as given in Table 3.4.

Table 3.4 Prevailing domestic energy tariff of Bhutan [42]

			From July 01, 2008	From July 01, 2009.
For Low Voltage Consumer		Energy charge US$/kWh		
Block I	Up to 80 kWh/Month		0.016	0.016
Block II	81-300 kWh/month		0.028	0.029
Block III	Above 301 kWh/Month		0.035	0.038
For Low voltage Bulk customer.			0.035	0.038
For Medium Voltage consumer(33/11/6.6 kV)		Energy charge	0.029	0.024
		Demand charge /month	1.556	1.764
For High Voltage consumer(66 kV and above)		Energy charge	0.023	0.031
		Demand charge /month	1.556	1.764

3.2.3. Future trade with neighboring countries

In the recent South Asian Association for Regional Corporation (SAARC) meeting held in Colombo, Sri Lanka on 27th January, 2009 decided to form "SAARC Energy Ring". The goal of the SAARC Energy Ring is to strengthen South Asian's capacity of efficient utilization and sharing of renewable energy resources within the region and to facilitate energy trade between the SAARC countries. The materialization of SAARC Energy Ring in near future would enable Bhutan to trade its electric power with other neighboring countries apart from India. Bhutan can play pivotal role as source of cheap energy in the region. The political stability in Bhutan compared to neighboring Himalayan country like Nepal which also have huge hydropower potential will also help establish its credibility as a reliable source of energy to energy-intensive industrial countries.

3.3. Calculation of End User Price

3.3.1. Determination of generation price

The Total cost of supply includes Operating and Maintenance (O&M) Cost, Depreciation, Return on Fixed Asset, Power Purchase and fuel cost for electric generation, cost f losses and non-payment of electricity bills, cost of working capital and regulatory fees, duties or levies that the licensee is liable to pay under the Laws of Bhutan. The total cost of Licensee in any year as determined by is determined by Authority as:

$$TC = OM + DEP + RoA + RoWc \tag{3.1}$$

where,

$$RoA = WACC \times NA \tag{3.2}$$

$$RoWC = WACC \times \left[REV \times \frac{ARREARS}{365} + INVENTORIES\right] \tag{3.3}$$

$$WACC = CoE \times \left(\frac{1-Gearing}{1-Tax}\right) + CoD \times Gearing \tag{3.4}$$

$$REV = OM + DEP + RoA \tag{3.5}$$

Where,

- TC is the total cost of supply
- OM is the allowance for operating and maintenance costs including any regulatory and other fees.
- DEP is allowance for depreciation of assets.
- RoA is return on fixed assets.
- WACC is the weighted average cost of capital
- NA is the net value of all the fixed assets at the start of the year.
- RoWC is the return on working capital.
- ARREARS is the allowed days receivables, in days
- An INVENTORIES is the allowance for the inventories.
- COE is the cost of equity in % determined by BEA.
- Gearing ratio is the standard ratio of debt to total fixed assets, as determined by the Authority.
- CoD is the cost of debt, as percentage, being the weighted average interest of Licensee's Loan.
- Tax is the prevailing rate of company taxation, as a percentage.

3.3.2. Determination of Average Cost of Supply

The Average Cost of supply is taken as the ratio of discounted annual cost of supply to the discounted energy volumes, with discounting applied over the Tariff Period using the WACC as given below,

$$AC = \frac{\sum_{n=1}^{TP} \frac{TC_n}{((1+WACC)^n)}}{\sum_{n=1}^{TP} \frac{ENERGY_n}{(1+WACC)^n}} \tag{3.6}$$

Where,

$$ENERGY = \sum_i ENERGY_i \times (1 - Aux_i) \times AVAIL_i \tag{3.7}$$

Where,

- AC is the average cost of supply for the Licensee
- TP is the number of years in the Tariff period.
- TC_n is the total cost of supply in year "n"
- $ENERGY_n$ is the energy volume in year "n".

- ENERGY is the annual energy volume in any year, in GWh.
- $ENERGY_i$ is the design energy, in the case of hydropower, or expected energy production, in the case of thermal plant, for plant "i"
- AUX_i is the allowance for auxiliary consumption at plant "i", as percentage.
- $AVAIL_i$ is the station availability allowance for plant "i", as percentage

3.3.3. Determination of Royalty Price

The Royalty Price is the average cost of supply lesser than the ratio of discounted subsidy amounts to the discounted royalty energy, with discounting applied over the tariff period using the WACC and is as below:

$$RP = AC - \frac{\sum_{n=1}^{TP} SUB_n / (1 + WACC)^n}{\sum_{n=1}^{TP} ROYALTY_n / (1 + WACC)^n} \qquad (3.8)$$

Where,

- RP is the Royalty Price per kWh.
- SUB_n is the subsidy amount in year "n".
- $ROYALTY_n$ is the amount of Royalty Energy in year "n".

Any energy delivered by the Generation Licensee to a Distribution Licensee above the Royalty Energy is termed Additional Energy and the price of additional energy is equal to Average Cost.

3.3.4. Determination of End User Price

Average price for each customer group that is determined by the authority in its price reviews according to the provision of regulation,

$$\mathbf{AP_c} = \frac{\sum_{n=1}^{TP} \mathbf{COST_{c,n}} / (\mathbf{1} + \mathbf{WACC})^{\mathbf{n}}}{\sum_{n=1}^{TP} (\mathbf{SALES_{c,n}} \times \mathbf{COLL}) / (\mathbf{1} + \mathbf{WACC})^{\mathbf{n}}} \qquad (3.9)$$

Where, Cost of supply for a customer group can be calculated as:

$$\begin{aligned} \mathrm{COST_c} = {} & (1 + \mathrm{LOSS_c}) \times \mathrm{PPP} \times \mathrm{SALES_c} + \mathrm{IP} \times \mathrm{IMPORT} \\ & \times \mathrm{IMALLOC_c} \, (\mathrm{NETWORK_c}) + \mathrm{WC_c} - \mathrm{REV_c} - \mathrm{SUB_c} \end{aligned} \qquad (3.10)$$

Annual Network cost allocated to each customer group can be calculated as:

$$\mathrm{NETWORK_c} = \mathrm{WACC} \times \sum_{\mathrm{i}} [\mathrm{ASSET_i} \times \mathrm{AALLOC_{i,c}}] + \sum_{\mathrm{i}} [\mathrm{DEP_i} \times \mathrm{AALLOC_{i,c}}] + \sum_{\mathrm{i}} [\mathrm{OM_i} \times \mathrm{OMALLOC_{i,c}}] + \mathrm{FEES} \times \mathrm{FALLOC_c} \tag{3.11}$$

Cost of working capital allocated to each customer group,

$$\mathrm{WC_c} = \mathrm{WACC} \times \mathrm{INV} \times \mathrm{IALLOC_c} \tag{3.12}$$

Power Purchase Price,

$$PPP = \frac{\sum_i [AP_i \times DOMESTIC_i]}{\sum_i DOMESTIC_i} \tag{3.13}$$

Where,

- $\mathrm{ASSET_i}$ is the net historical value of assets in asset category “i”
- $\mathrm{DEP_i}$ is the depreciation allowance for assets in asset category “i”
- $\mathrm{OM_i}$ is operating and maintenance allowance for cost category “I”
- FEES is the allowance for fees and levies.
- $\mathrm{AALLOC_{i,c}}$ is the allocation factor to Consumer category “C” for asset-related costs in asset category “i”, as percentage, where $\sum_c AALLPC_{i,c}$ =1
- $\mathrm{OMALLOC_{i,c}}$ is the allocation factor to customer “C” for O&M in cost category “i”, as percentage, where $\mathrm{OMALLOC_{i,c}} = 1$
- FALLOCC is the allocation factor for fees, as a percentage, where $\sum_c FALLOCC_{i,c} = 1$
- $\mathrm{IALLOC_c}$ is the allocation factor to customer category “C” for inventories, as percentage $\sum \mathrm{IALLOC_c} = 1$.
- INV is the allowance for the value of inventories.
- AP_i is the additional price for generator “i”.
- $DOMESTIC_i$ is the volume of electricity supplied to the Licensee by generator “i” in GWh.
- IP is the average import price per kWh.
- $\mathrm{REV_c}$ is the estimated Non-Tariff revenue for the year arising from customer group “C”.
- $\mathrm{SALES_c}$ is the sales for the year attributed to customer group “C” in kWh.
- $\mathrm{LOSS_c}$ is sum of technical and commercial loss allocated to customer group “C” , as a percentage.
- $\mathrm{SUB_c}$ is amount of subsidy allocated to customer group “C”.
- COLL is the target collection rate set by the Authority for the Licensee, as percentage.
- $\mathrm{COST_{c,n}}$ is the cost if supply allocated to customer group “C” in year “n”.
- $\mathrm{SALES_{c,n}}$ is the volume of electricity sales expected from customer group “C” in year “n” in GWh.

3.4. Need for Competitive Electricity market in Bhutan

- **Increase demand in Electricity**

The growth of load in eastern and western Bhutan from the year 2007-2008 in % and load projected for next ten years by DOE is given in Appendix A (Fig.A1.1-A2.1). The demands will almost double the existing amount in less than next ten years.

- **Electricity tariff**

The electricity tariff for LV customer increased from Nu. 1.55 Per unit in July, 2007 to Nu. 1.85 per Unit in July, 2009(comes into effect from 1st July, 2009)[42].

The Bhutanese people feel that government should bring down the cost of electricity further down instead of increasing every year. It is important to mention here that most of people in Bhutan live in rural areas. Though Bhutan have low electricity tariff compared to other countries, the affordability for the same by Bhutanese people with that of developed world is not comparable.

On the contrary, the survey done by Rural Electrification Department (RED) found that the cost of delivering the electricity to each household is US$ 0.08 – 0.1 per unit. The government allocates 15% of the electricity generated to BPC for domestic consumption at subsidized royalty charges. The government can afford to subsidize the rate from the revenue earned from export of power.

But constant revision and increase in tariff will discourage the development of growth of Bhutanese industries by reducing their competitive edge and electricity usage in the country. It is very important to bring down the cost of generation and supply to affordable level and help the growth of power sector and dependent industries. This calls in for further liberalization of electricity market.

- **To take advantage of the power deficit and growing economy in the neighboring countries**

Table 3.5 List of present Power shortage in neighboring countries

Country	Energy shortage	Remarks
India	6743 MU	In April, 2009. Monthly Review of Power Sector by CEA, GOI.
Pakistan	2,000 MW	In May, 2009. As informed by NPCC to Dawn News site.
Bangladesh	2,000 MW	In April, 2009. Source: Reuter News.
Nepal	500 MW marked with constant load shedding.	In January 2009, online news.

The neighboring countries can make use of cheap source of energy in Bhutan to address their acute power shortage as illustrated in Appendix B , Table B1.1. The gap between supply and demand in industry intensive and booming economy like India and China will widen further in coming years. Bhutan can export or participate in the energy market of neighboring countries in future as one of the cheap and reliable supplier of electricity. At present, the trade of energy with the neighboring country, India, the rate is already fixed as per the bilateral contract signed between two countries. Since Bhutan's grid is connected to North-Eastern grid of India, Bhutan can also participate in India's competitive electricity market.

- **Encourage private investment in Generation.**

Bhutan relies on donor agency like Indian government to build hydroelectric project. Deregulation will encourage private investment in developing the generation capacity in the country.

At present all the generation companies comes under one umbrella- DGPC, the pool market formed similar along the line of Nord Pool for trade of energy within the country encourage more participation from private sector. DGPC can function like central market operator to co-ordinate and facilitate the operation of competitive market.

CHAPTER 4: PROPOSAL FOR ELECTRICITY MARKET MODEL FOR BHUTAN

This Chapter describes the competitive market model developed in this thesis. It presents the simulated result of proposed model in OPF based Market and Uniform Price Market under various cases. The bidding blocks of Day-Ahead market is also presented. Based on the results of simulation and analysis, the appropriate market model suitable for existing Bhutan Power system is recommended.

4.1. Description of the conceptualized model

The Bhutan Power system is divided into four areas at least including one generating unit in each area from the major existing generation plants in the country. The upcoming and future power plant which is either under construction or in Detailed Project Report (DPR) stage [41] is not included in the model. Each area is assumed to be interconnected to each other as eastern and western grids are isolated at present. But the interconnection is proposed to be taken up in near future. Each area has its own demand and supply. The model consists of 48 buses and it is allocated in each area depending on its proximity to the generating plant.

The slack bus is taken as Indian grid to which Bhutan Power system is well connected. The reason being attempt had been made to model the power system to the real network as much as possible. The present load flow in Bhutan is modeled with Equivalent Indian grid as slack bus. Green Areas indicate the nature of generation in that region is hydro.

Power Market Areas can be visualized as give in Figure 4.1:

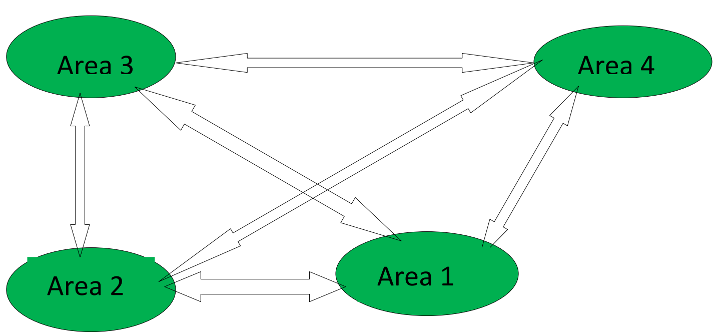


Figure 0.1 Power Market Areas

4.2. Assumption made.

The power system is modeled for deregulated and competitive electricity market where the suppliers, buyers and everyone involved in the electricity market will come together to trade electricity like any other commodity. All the four areas are assumed to be well interconnected with each other.

The real Bhutan Power system network along with inter-connected corridor of Indian grid is modeled in power world for its economic dispatch. Some of the loads (small loads ranging from 1-2 MW) had been lumped together to keep the number of buses in the system below 50. The system is modeled for bus voltage equal to and above 11 kV .It is assumed that would have little or almost negligible effect on the whole system.

The Linear cost characteristic of the generation is assumed. The cost of generation in this model accounts only for Operation & Maintenance (O &M) as the fuel cost is zero in hydroelectric power plant.

4.3. Organized Market

The Pool Market structure similar to one existing in Australia is given in Figure 4.2.

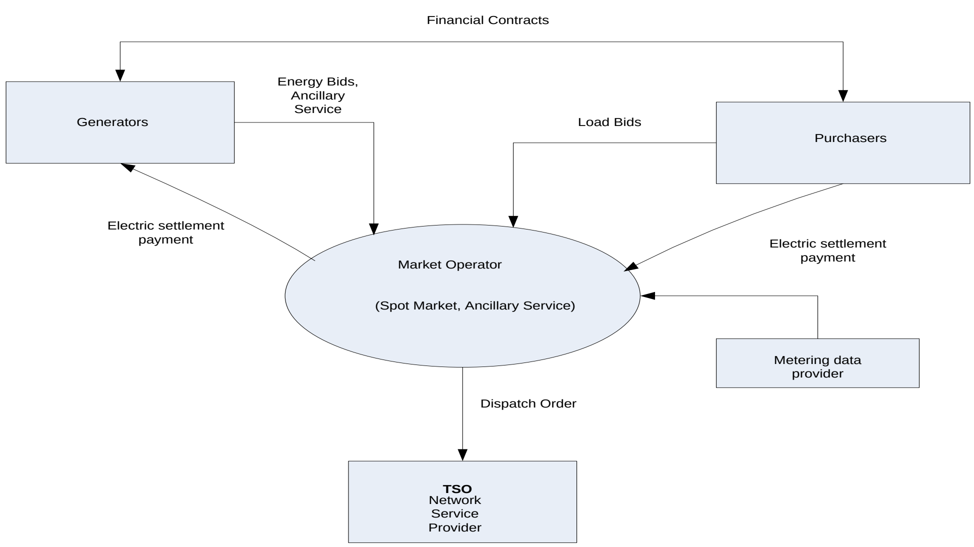


Figure 0.2 Pool Market Structure similar [70]

- *Spot market*: The participants (buyers and sellers) submit their bids on an hourly basis in day-ahead market. These bids are then aggregated by the market operator. The intersection point of total demand and supply curve is obtained which corresponds to Market Clearing Price (MCP). The spot market in this way is settled daily at noon, 24 hours ahead of its next delivery.

- *Regulating market*: This market is mainly to adapt the generation to fluctuation in load or for the load side to adapt to fluctuation in generation. The producer and consumer submit its bid to system operator - the willing quantity and prices for up or down regulation for number of hours. In the real time the market operator as per the merit order list will select the cheapest regulator. So all the regulator will receive the price of the marginal regulators.
- *Future market*: The trading in future market is weekly basis and is purely a financial market. The future market involves purchase of weekly base or peak load contracts.
- *Bilateral market*- It is not really organized market. Here the two parties can enter into contract with each other to sell and buy electricity. The long term contract will also reflect the trend of spot price development.

The future market and bilateral market will help hedge the risk and uncertainties involved with volatile spot market price.

4.4. Proposed Market Type 1: OPF Based Market

4.4.1. Discussion on OPF

Optimal Power Flow (OPF) is defined in early 1960s as *"an extension of conventional Economic Load Dispatch (ELD) problem to determine the optimal setting for control variables while satisfying various constraints*". The Power flow always follow the physical law of electricity and network configuration as established by the Kirchhoff's law, and are commonly known as *Load Flow Equation.* When these load flow equation are introduced in ELD as a system of demand/supply constraints, the optimal solution yields a decision variables satisfying the physical law of power flow while achieving a desired objectives (of cost minimization, lost minimization etc.) [57].

An OPF model can incorporate various system constraints in addition to system variables as per the problem requirement. The OPF set-up can include one or more of the following variables:

- Real and Reactive Power generation
- Load MW and MVAr (Load Shedding)
- LTC Transformer tap settings etc.

OPF simulation is used for medium term planning studies like Reactive Power planning, production scheduling, maintenance scheduling and also for long term studies, viz. generation and transmission planning carried out a year ahead. OPF simulation of every 30 minutes is carried out by system operator for optimal dispatch and control action that needs to be taken [20], [68].

4.4.2. Discussion for Location Marginal Price (LMP)

The Locational Marginal Price usually consists of three components- (i) System Marginal Cost of generator (ii) Network Loss component and (iii) Network constraint element. It can be expressed mathematically as [26], [50]

$$\rho k = \curlywedge + \curlywedge . \frac{\partial L(zi)}{\partial dk} + \sum \mu i \frac{\partial zi}{\partial dk} \tag{4.1}$$

Where, dk is demand at node, k

zi is power flow across line, i

L(zi) is transmission losses as function of line flow

μi, Lagrange multiplier of third term, is the shadow price of transmission line, i, under the Congested and limited transfer capability limit.

The system Marginal cost at bus, k, is same as marginal cost of swing bus and is derivatives with respect to power generation. In an interconnected Power system, the change in demand and generation will cause change in total system losses locational marginal price.

Locational Marginal Price (LMP) based on nodal price is used in several USA market like PJM, L.L.C in Pennsylvania, NJ and Maryland. LMPs are calculated for the modeled generator buses, load buses, interfaces buses and buses with inter-connected control areas outside the system considered. For accurate modeling of LMP of the actual operating condition the following should be considered:

4.1. Economic dispatch
4.2. Dispatchable transaction
4.3. All external transaction
4.4. Detailed generating resource data
4.5. Generating constraints
4.6. List of binding transmission constraints
- Demand- supply balance.

LMP can be very accurate price signal in the power market as it also includes the cost of losses and congestion cost. In other words, the transmission charge is not separate from the supply charges here. In real time market the dispatch based on LMP like PJM not only meet the energy demand but it also satisfy the transmission constraints using the least-cost security constrained economic dispatch program. To aide our understanding on it, PJM LMP model can be studied as shown in Figure 4.3 as illustrated in the paper [49].

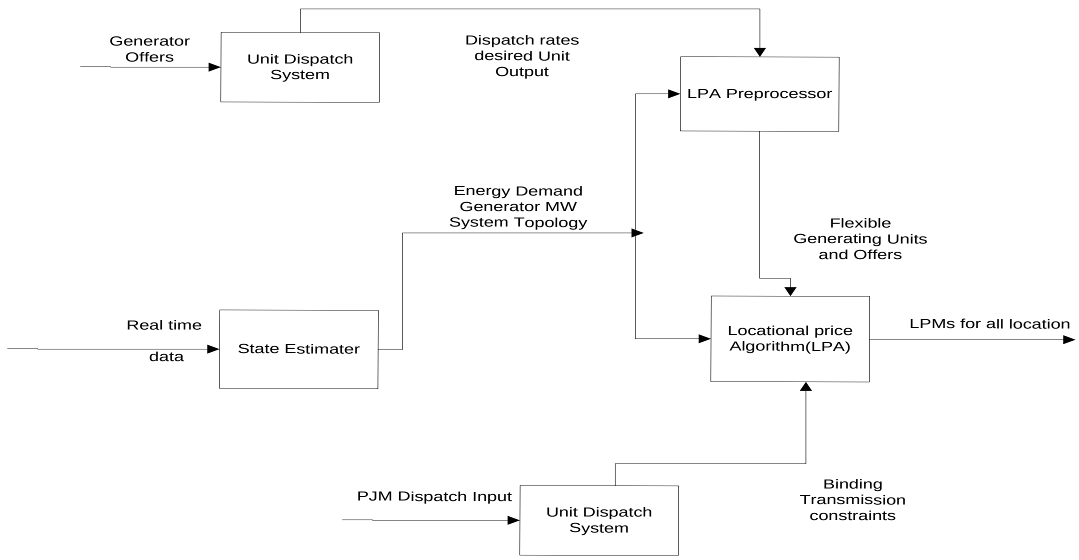


Figure 0.3 Functional diagram of PJM LMP Model

In LMP model, the price difference between the injection point and withdrawal point is the congestion price.

4.3.2.1 Advantage of using LMP over uniform pricing method:

LMP as a pricing mechanism is an indicator of cost of maintaining the secure operation of the network and it includes the transmission congestion. LMP is the actual cost of energy in that area taking into accounts all the locational constraints.

LMP reflects the co-ordination of energy generation in such a way that the total supply of generation can adjust to the constantly changing demand.

- If reserve price is precisely considered, LMP might have strong possibility to provide an economic tool or reserve supply for system security in the energy reserve market.

4.4.3. Discussion on Bhutan Power System

In 1966, the electrification started with installation of 25 kW diesel generators set In Phuentsholing. The first Bhutan's hydropower was commissioned in 1967 with an installed capacity of 360kW to supply power to capital, Thimphu. The Chukha Hydropower (336 MW) was the first major hydropower to be constructed and commissioned with joint effort of GOI and RGOB in 1988. Since then, the total installed capacity has increased to approximately 1488 MW. The detail of Generation in Bhutan is given in Appendix C, Table C1.1. The commissioning of Chukha saw rapid growth in Industrial load and the total load so far sanctioned by BPC in the country is almost 220 MW. The Total summer and winter load is given in Appendix C, Table C2.2. The transmission network in Bhutan is still at its infancy stage. The Eastern and Western grid within Bhutan are isolated from each other at the moment but inter-connection of eastern and western grid and formation of national grid is in the process. The total transmission network at present covers 13 Dzongkhags with about 803.043 Km of line length (66, 132, 220 & 499 kV) and 22 substations (619.5 MVA). The Transmission line details are given in Appendix C, table C2.3. Bhutan grid is connected to Indian grid through the following inter-connecting lines:

- Chukha(Bhutan) – Birpara(India) 220kV 3 Circuits.
- Geylegphug (Bhutan) – Salakati(NER) 132 kV Line.
- Motanga (Bhutan)-Rangia (India) 132 kV Line.
- Tala (Bhutan) – Siliguri 400kV (2 Double Circuit) Line.

Bhutan exports 70% of the total power generated to India through above interconnecting lines.

4.4.4. Discussion on PowerWorld Simulator Tool

Power World software is used as a tool to simulate LMP Based Market. Power World Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a wide time range of time frame. This software package is capable of efficiently solving systems up to 100,000 buses. It offers several add-ons simulation capabilities like Optimal Power Flow, OPF Reserve, Security Constrained OPF (SCOPF), Available Transfer capability (ATC), PVQV curve tools, Simulator Automation Service and Transmission line Parameter Calculation (TransCal). OPF Simulator and TransCal simulator is mostly used in this thesis. Simulator OPF provides the ability to optimally dispatch the generation in an area or group of areas while simultaneously enforcing the transmission line and interface limits. Simulator OPF c then calculates the marginal price to supply electricity to a bus (Locational Marginal Price or LMP), while taking into account transmission system congestion [17]. Linear Programming based OPF package is used to obtain LMP for the proposed model as it also mitigates constraints on the most economic fashion with maximization of Social Welfare as its objective function contains highly effective power flow analysis.

4.4.5. Optimal Power Flow (OPF) of Bhutan Power System Network

In order to run OPF simulation to obtain LMP for Bhutan Power system, the Buses in the network are divided into above four different areas with each area having its own generating unit and loads as shown in the Fig. 4.2. The cost of production of energy per unit in is calculated using only the Operation and Maintenance (O & M) cost and Annual Energy density since the fuel cost of hydro is zero. The linear cost function of different generator is modeled using the cost given in Table 4.1.

The OPF of the system is successfully obtained assuming that the whole system is running at peak generation and load. The voltage stability limit and reactive power balance were not violated except that under voltage (highlighted in red) was observed in Gomtu & Samtse Buses voltage as shown in Figure 4.4 , which exists in real system too. The whole Bhutan network is then divided into four areas, each generating plant constituting one area except for Rurichu and Basochu generating unit which is lumped under Area II.

The OPF Bus record obtained from the simulation is given in Appendix D, Table D.1. The OPF generator record is given in Table 4.2.

Table 0.1 Cost of generation of each plant

Generating Plants	O&M cost in Million(SEK)	Annual Energy volume(GWh)	Cost of generation (SEK per MWh)
CHPC(330 MW)/ Area III	96,624	1800	53.73
BHPC(24 MW)/Area II	5.473	291	18.92
RHPC(40 MW)/Area II			
KHPC(60MW)/ Area I	15.965	400	39.985
THPA(1020 MW)/Area IV	0.0749 SEK/kWh		74.32

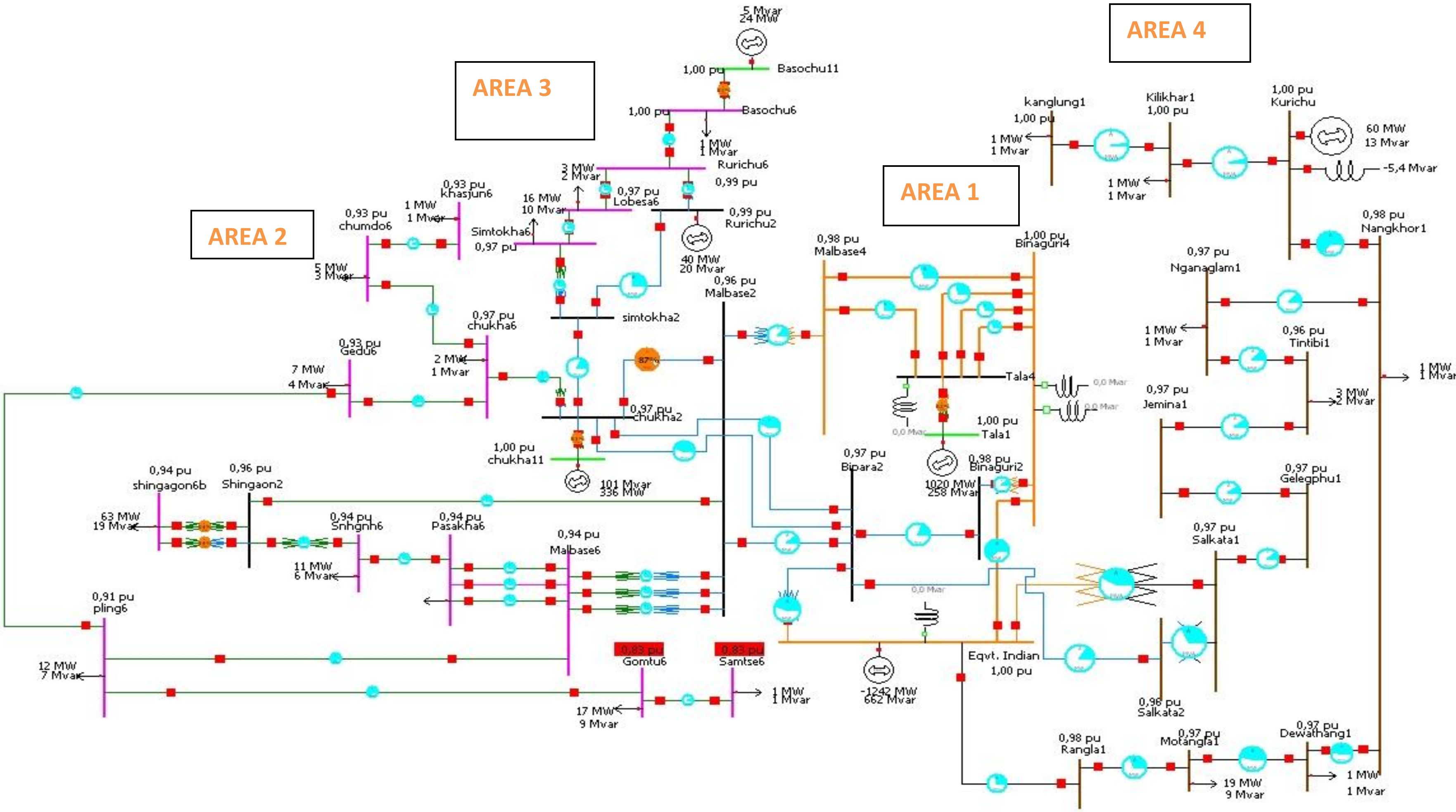


Figure 0.4 Bhutan Power system Model divided into four Area.

4.5. Calculation of Locational Marginal price for various cases (LMP)

Case 1: Business as Usual (BAU)

The LMP for the model is calculated after feeding in the linear cost function of generator. It is taken as piece wise linear approximation. The OPF model is simulated to get Primal OPF LP solution. The LMP is synonymous to optimizing the system for maximizing social welfare, which is the objective function here. The main idea for modeling LMP is to model an electricity market with its various economic and technical specifications which as generator cost function, demand elasticity, generation limits, line flow limit etc. ISO clears the market price after collecting all the bids with its objective function of social welfare maximization while satisfying the network constraints.

The contour for LMP for different area obtained from simulation of the model is as given in Figure 4.5. The red region indicated high LMP and the least LMP is blue region.

The LMP is lowest in Area 3 because of cheaper cost of generation and it is highest in Area 1 and some part of Area 4. There are two plants in Area 3, the OPF and Linear Programming switches off one plant as the other plant is enough to meet the demand in that region. The comparatively high cost in Area I can be due to high cost of generation and also due to network congestion in these areas.

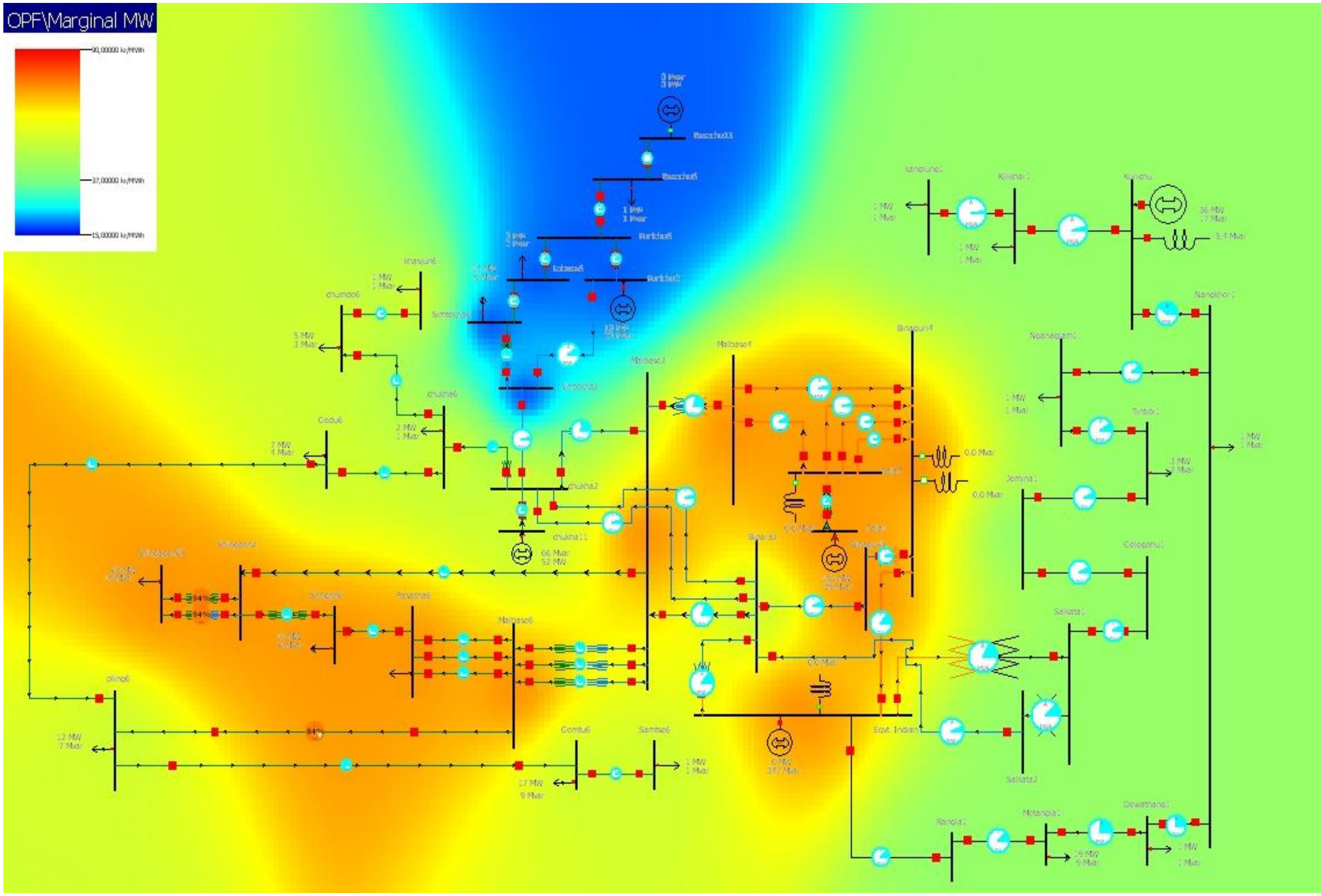


Figure 0.5 Bhutan Power system model showing different LMP region

Figure 0.6 Market Clearing Price of LMP bids

The LMP in four Areas after the market simulation is given in Table 4.2.

Table 0.2 LMP in different Areas after simulation

OPF Area Record			
Area Name	**AGC Status**	**Include Marg. Losses**	**MW Marg. Cost Ave**
Area1	OPF	YES	74,45
Area2	OPF	YES	55,45
Area3	OPF	YES	18,95
Area4	OPF	YES	41,11

The nodal price at each bus varies from each other and is determined by MW demand and supply and their location which reflects the system loss and network congestion. The cost of generation obtained from the OPF model after Primal LP simulation is as given in Table 4.3.

Table 0.3 Total cost of Generation

OPF Generator Records														
Name of Bus	**Area Name of Gen**	**AGC**	**Fast Start**	**OPF Fast Start Status**	**OPF MW Control**	**Gen MW**	**Cost kr/Hr (generation only)**	**MW Marg. Cost of Bus(kr)**	**IC for OPF**	**Initial MW**	**Min MW**	**Max MW**	**Cost Model**	**Fuel Type**
chukha11	Area2	YES	YES		If Agcable	51,4	2863.43	53,73	53,73	51,4	0	336	Piecewise Linear	Hydro
Rurichu2	Area3	YES	YES		If Agcable	19,2	463,38	18,92	18,92	19,2	0	40	Piecewise Linear	Hydro
Basochu11	Area3	YES	YES	Set off by OPF	If Agcable	0	0	18,91	0	0	0	24	Piecewise Linear	Hydro
Tala1	Area1	YES	YES		If Agcable	1020	75906.4	74,32	74,32	1020	0	1020	Piecewise Linear	Hydro
Eqvt. Indian Bus	Area1	NO	YES		If Agcable	-860,7	100	75,34	0	-860,6	-1200	0	Piecewise Linear	Unknown
Kurichu	Area4	YES	YES		If Agcable	36,3	1549.75	39,99	39,99	36,3	0	60	Piecewise Linear	Hydro

It is observed that the marginal cost of the generator bus as shown in Table 4.3 is same as the current marginal cost that is used as Linear Cost Model parameter for this proposed Market. This indicates that the generator in all the area is available for control and has not hit is maximum or minimum limit. It also means the transmission network is not congested and the load is not big enough either.

Case 2: BAU + Loss of critical transmission line:

The transmission line in Area 1 between Malbase 2 and Shingaon 2 is opened to study the effect on tripping critical line on the network and to the pricing in different areas as seen in Figure 4.6. The line is chosen because it is the main transmission line that supplies power to energy intensive industry.

It is hence observed that the loss of critical transmission line as shown in Figure 4.5, causes overload of transmission line in that region leading to under-voltage in the effected buses as compiled in Table 4.4. This leads to increase in LMP in Area 1 because of network congestion, violation of constraint limit of transmission line and bus voltage as illustrated in Table 4.5. The LMP contour in Figure 4.6 shows that price is much higher in Area 1 compared to BAU case.

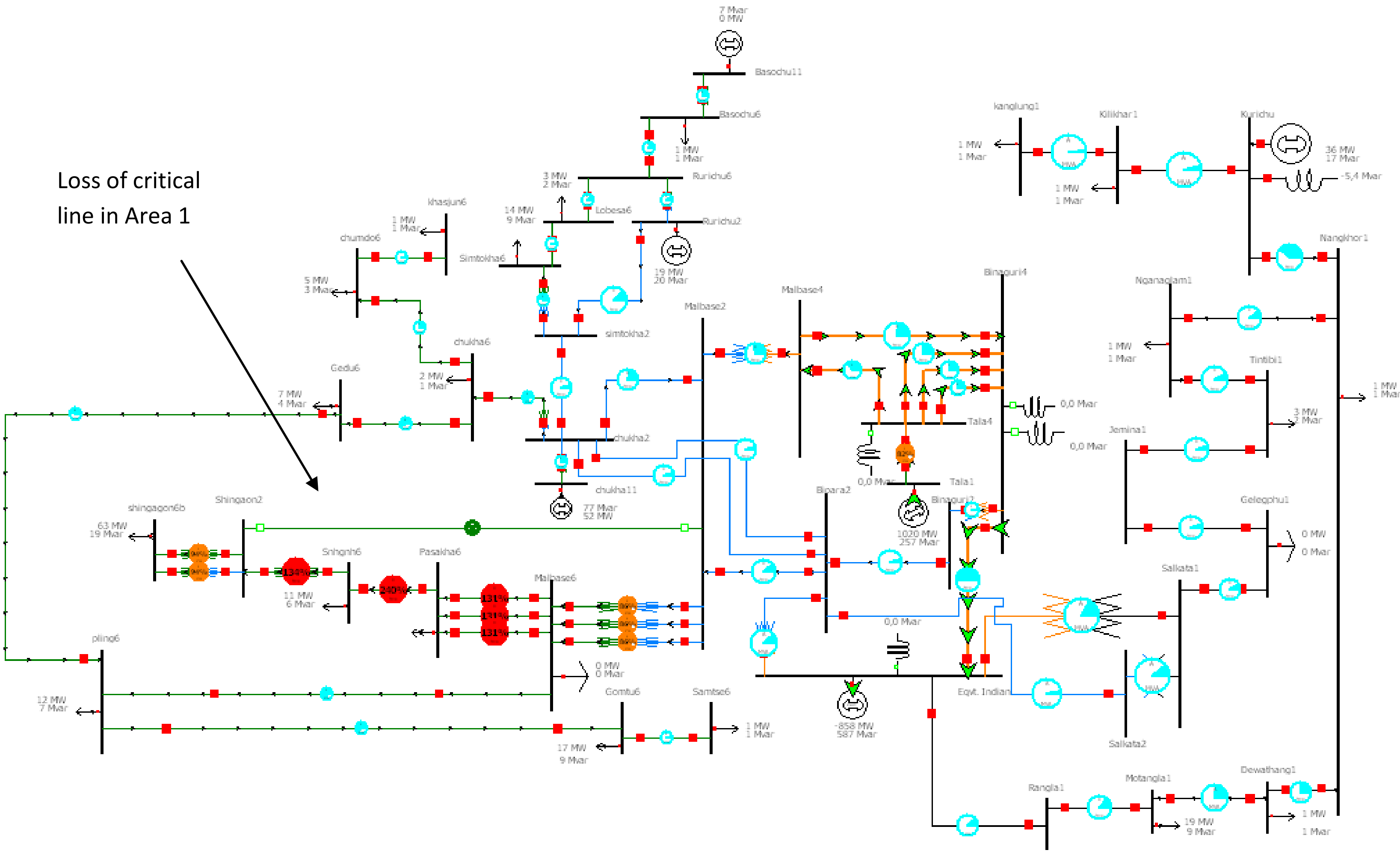


Figure 0.7 The simulated network with loss of critical transmission line

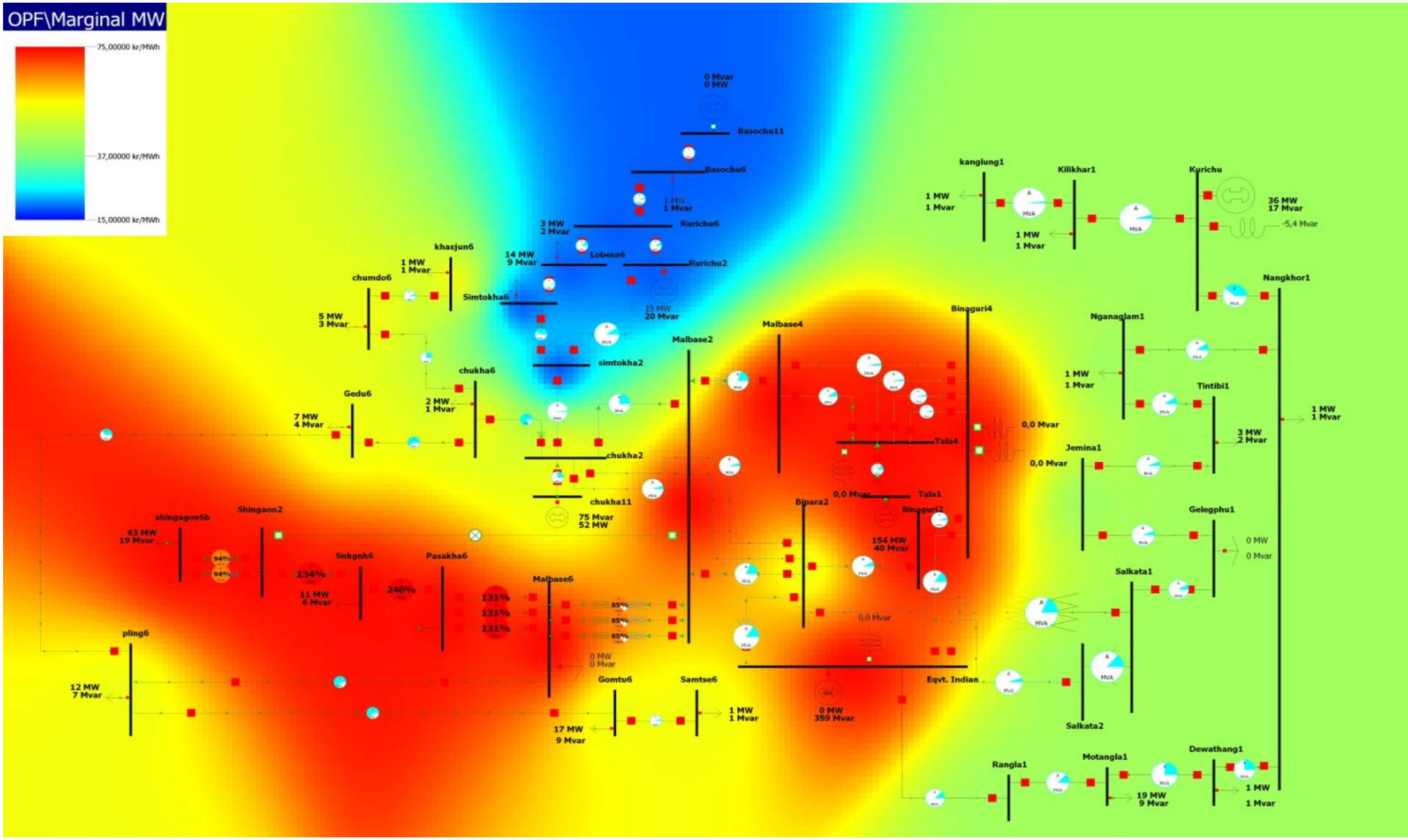


Figure 0.8 Contour of LMP for different Areas under outage of critical transmission line

Table 0.4 Bus record of violated voltage limit under loss of critical transmission line

Bus Records							
Number	**Name**	**Area Name**	**Nom. kV**	**PU Volt**	**Volt (kV)**	**Load MW**	**Load Mvar**
11	Shingaon2	Area1	220	0.873	191.99		
12	shingagon6b	Area1	66	0.857	56.56	63	19
13	pling6	Area2	66	0.898	59.28	12	7
14	Gomtu6	Area2	66	0.819	54.07	17	9
15	Samtse6	Area2	66	0.817	53.91	1	0,5

The under-voltage at the buses in Area 1 and Area 2 in Table 4.4 Signals that reactive power compensation is required.

Table 0.5 LMP and generation cost with loss of critical transmission line.

Area Name	AGC Status	MW Marg. Cost of Gen. (SEK)	Avg. MW Marg cost of Area (SEK)
Area1	OPF	74.37	837.55
Area2	OPF	53.72	58.88
Area3	OPF	18.92	19.05
Area4	OPF	39.99	41.25

Case 3- BAU +Loss of cheap Generating Unit (Area 3):

The OPF of the network under loss of cheap generating unit have no significant effect on the LMP and price of generation as shown in Table 4.6 and Figure 4.7. Area 3 have the cheapest generating unit but it has two generating station in that area. The other plant acts like a back up during the outage of one generating station.

Table 0.6 - LMP and generation price in different Area under loss of cheap generating unit

Area Name	AGC Status	MW Marg. Generator(SEK)	Avg. MW Marg Cost (SEK)
Area1	OPF	74.45	74.71
Area2	OPF	55.45	55.84
Area3	OPF	18.95	18.95
Area4	OPF	41.11	41.11

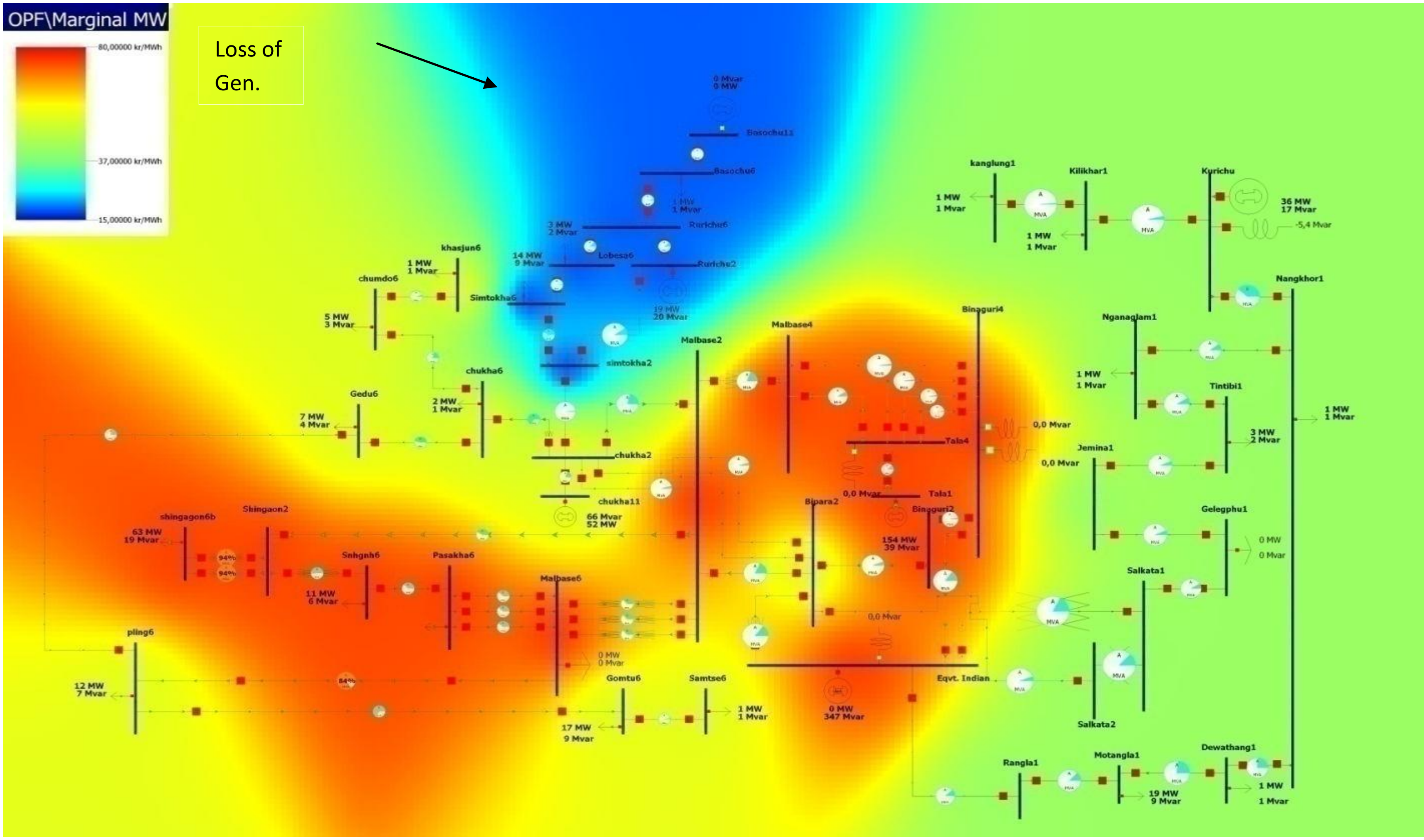


Figure 0.9 LMP contour in different Areas under the loss of cheap generating unit

Case-4 : BAU plus Constrained line(violating the limit of line):

The MVA of all the line were reduced by half and simulated. It resulted in the violation of limit of following lines. The MVA limit for more than 50% for transmission lines is compiled as below.

By reducing the MVA limit of the lines, the transmission capacities of the lines are greatly reduced. The transmission line with MVA violation above 50 % is as compiled in Table 4.7. The violation of transmission line limit is severe in Area 1 and Area 4; therefore it causes network congestion resulting in big increase in LMP in those Areas as shown in Figure 4.8. The lowering of MVA capacity of line does cause significant increase in LMP in Area 2 and Area 3 as well but less than that of Area 1 and Area 4 as shown in Table 4.8.

Table 0.7 The transmission lines with its MVA limit violated.

From Name	Area	To Name	Area	Monitor	Max MVA	% of MVA Limit (Max)	Lim MVA	Constraint Status
chukha6	Area2	chukha2	Area2	YES	26.03	131.40	20.00	Unenforceable
Gedu6	Area2	chukha6	Area2	YES	16.10	94.00	17.10	
Malbase6	Area1	Malbase2	Area1	YES	23.50	74.70	31.50	
Malbase6	Area1	Malbase2	Area1	YES	23.50	74.70	31.50	
Malbase6	Area1	Malbase2	Area1	YES	23.50	74.70	31.50	
Shingaon2	Area1	Malbase2	Area1	YES	92.50	82.30	112.40	
Pasakha6	Area1	Malbase6	Area1	YES	13.20	77.10	17.10	
Pasakha6	Area1	Malbase6	Area1	YES	13.20	77.10	17.10	
Pasakha6	Area1	Malbase6	Area1	YES	13.20	77.10	17.10	
pling6	Area2	Malbase6	Area1	YES	30.00	175.60	17.10	Unenforceable
Snhgnh6	Area1	Pasakha6	Area1	YES	12.80	74.70	17.10	
Shingaon2	Area1	Snhgnh6	Area1	YES	25.60	102.50	25.10	Unenforceable
shingagon6b	Area1	Shingaon2	Area1	YES	33.40	194.60	17.10	Unenforceable
shingagon6b	Area1	Shingaon2	Area1	YES	33.40	194.60	17.10	Unenforceable
pling6	Area2	Gomtu6	Area2	YES	22.40	128.10	17.50	Unenforceable
Simtokha6	Area3	simtokha2	Area3	YES	16.40	82.10	20.00	
Rangla1	Area4	Motangla1	Area4	YES	11.50	51.20	22.50	
Motangla1	Area4	Dewathang1	Area4	YES	21.30	94.60	22.50	
Dewathang1	Area4	Nangkhor1	Area4	YES	22.80	101.30	22.50	
Kurichu	Area4	Nangkhor1	Area4	YES	34.80	77.40	45.50	Unenforceable

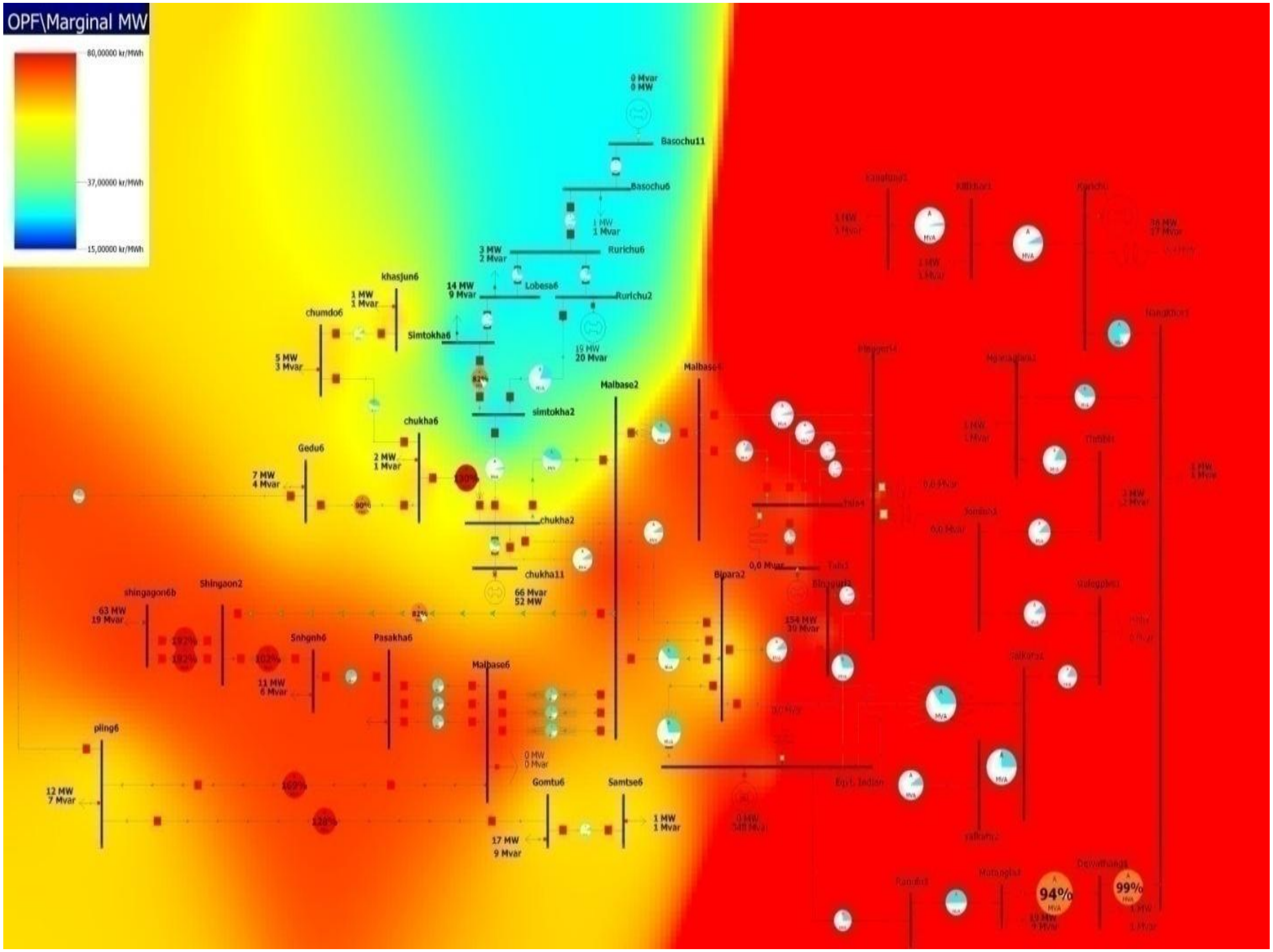


Figure 0.10 LMP contour for different Area for violation of transmission line MVA limit

Table 0.8 - LMP and MW Marg. Cost of generator in different Areas

Area Name	AGC status	MW Marg Cost of Gen.(SEK)	Avg. MW cost of Area(SEK)
Area 1	OPF	74.33	217.44
Area2	OPF	53.73	1007.28
Area 3	OPF	18.94	18.98
Area4	OPF	39.97	443.05

Case 5 - BAU plus increase and decrease in load:

In order to observe the effect of increasing or decreasing of the load on the power system network and ultimately to the price in different area, the load buses are scaled uniformly using Power World scaling shown in Table 4.9.

Table 0.9- Scaling of Load buses

BAU Load	Bus scaled	Scaling Factor	Case Load
214.50 MW	Load Bus	1.50	**321.75 MW**
214.50 MW	Load Bus	0.40	**85.80 MW**

i. For increase in Load.

The increase in load leads to overloading of some transmission lines in Area 1 and Area 2 as seen leading to voltage limit violation in the some of the buses in Area 2 as shown in Figure 4.10 and Table 4.10:

Table 0.10 - Voltage limit violation in bus under increased load.

Limit violated Bus Records							
No.	**Name**	**Area Name**	**Nom kV**	**PU Volt**	**Volt (kV)**	**Load MW**	**Load Mvar**
4	Gedu6	Area2	66	0,89914	59.343	9.75	6.06
6	khasjun6	Area2	66	0,89905	59.337	1.50	1.50
13	pling6	Area2	66	0,87350	57.651	18.00	10.50
14	Gomtu6	Area2	66	0,74148	48.938	25.50	13.50
15	Samtse6	Area2	66	0,73754	48.677	1.50	0.75

The congestion in the lines leads to LMP increase in Area 1 and Area 2 as shown in Table 4.11.

Area 2 LMP shoots up to an alarming price. This indicate that the network in Area 2 require network reinforcement with reactive power as its already existing under-voltage problem in Gomtu and Samtse bus dips further down.

Table 0.11 - LMP and Generation cost in different area for the increased in load case

Area Name	AGC status	MW Marg. Cost of Gen. (SEK)	Avg. MW Marg. Cost of Area (SEK)
Area 1	OPF	74.33	159.18
Area 2	OPF	53.75	1 069.16
Area 3	OPF	19.00	19.18
Area 4	OPF	39.99	41.76

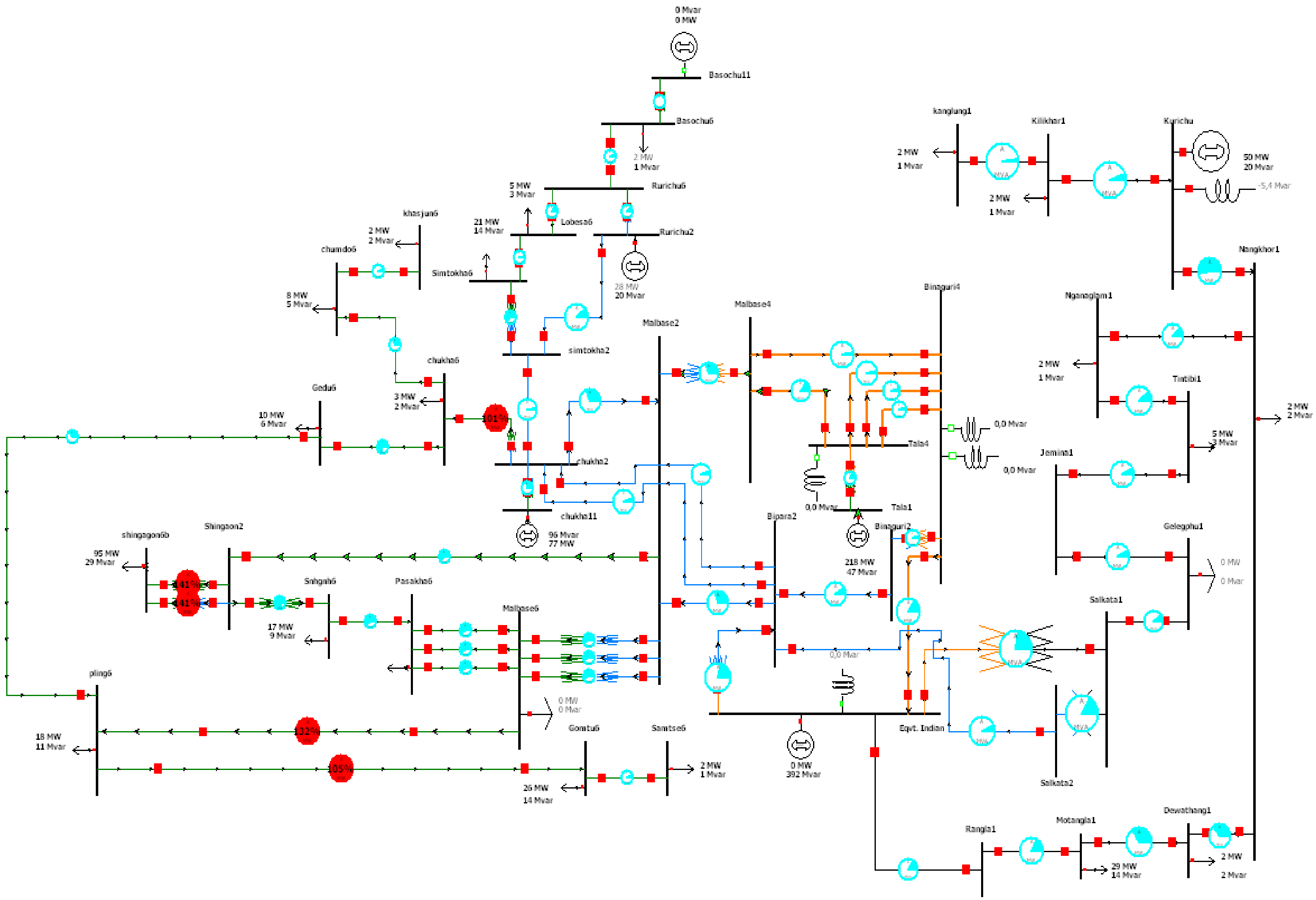


Figure 0.11 The simulated power system network for increased load.

ii. Decrease in Load

On simulation it is found that when the load is scaled down by scaling factor of 0.4, no violation of any sort is observed. Instead it leads to the voltage profile improvement of otherwise existing under-voltage profile in Gomtu and Samtse buses (Area 2) which exists in real system and in BAU case as shown in Table 4.12.

Table 0.12 LMP and Generation cost in different area for the decreased in load case

Area Name	AGC status	MW Marg. Cost of Gen.(SEK)	Avg. MW Marg. Cost of Area (SEK)
Area 1	OPF	74.33	74.38
Area 2	OPF	53.75	54.28
Area 3	OPF	18.92	18.93
Area 4	OPF	39.99	40.58

4.6. Comparison for LMP for different cases

As shown in the Fig. 4.11,The LMP of Area 1 is highest when a critical transmission line trip (belong to the same Area). The price in all the areas is not affected by taking out of cheap generating unit (Area 3) as there is another plant in the same area that supplements for loss of generation. LMP increases and drastically in Area 2 under the transmission line constraint and increased load condition. It also increases comparatively in Area 1 and 4 under these conditions. The decrease is load does not affect LMP of anyone of the Area and LMP is almost same to BAU case.

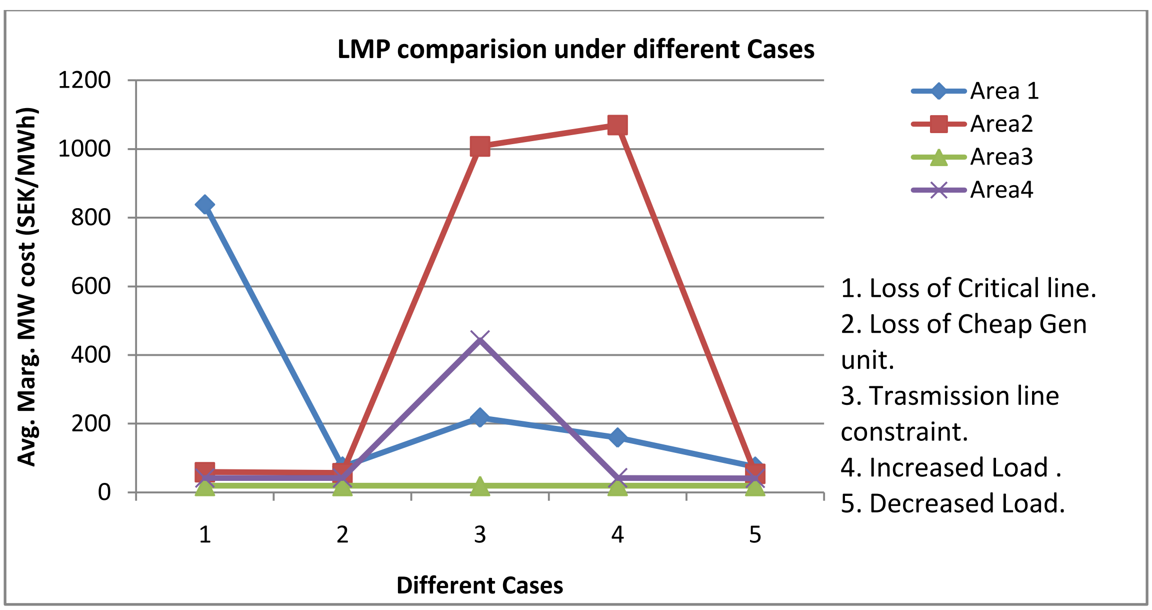


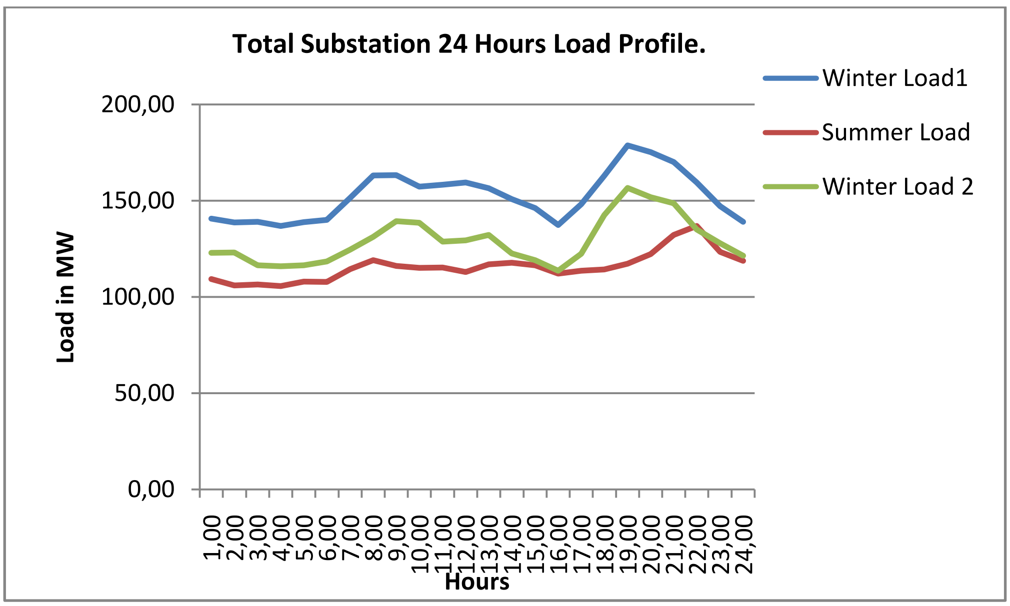
Figure 0.12 LMP for different cases for all the four areas

Load duration curve serve as a base around which the optimal dispatch of generating capacity is determined.

The load forecast for 24 hours is obtained to meet the demand from various suppliers bidding in the spot market. Here, the market price for one hour will be obtained. In order to do that, 24 hours load profile from 15th June, 2008 is assumed to be our load forecast for the 24 hours. The particular data is chosen as peak generation is considered for supply curve which is usually during the summer when the water is abundant in the river.

The 24 hours load profile varies according to the hour in a day. In order to obtain a smooth load profile, it is normalized with respect to its peak load.

4.7. 24 Hours Day-Ahead Market.



- Hourly peak Load for summer = 136.83 MW
- Hourly peak load1 for winter = 178.73 MW
- Hourly Peak Load2 for winter = 156.67 MW

Figure 0.13 Twenty four Hours Load duration for Total Sub-station

The peak load is taken as base load to normalize the 24 hours load profile. The result is a normalized profile as given in below.

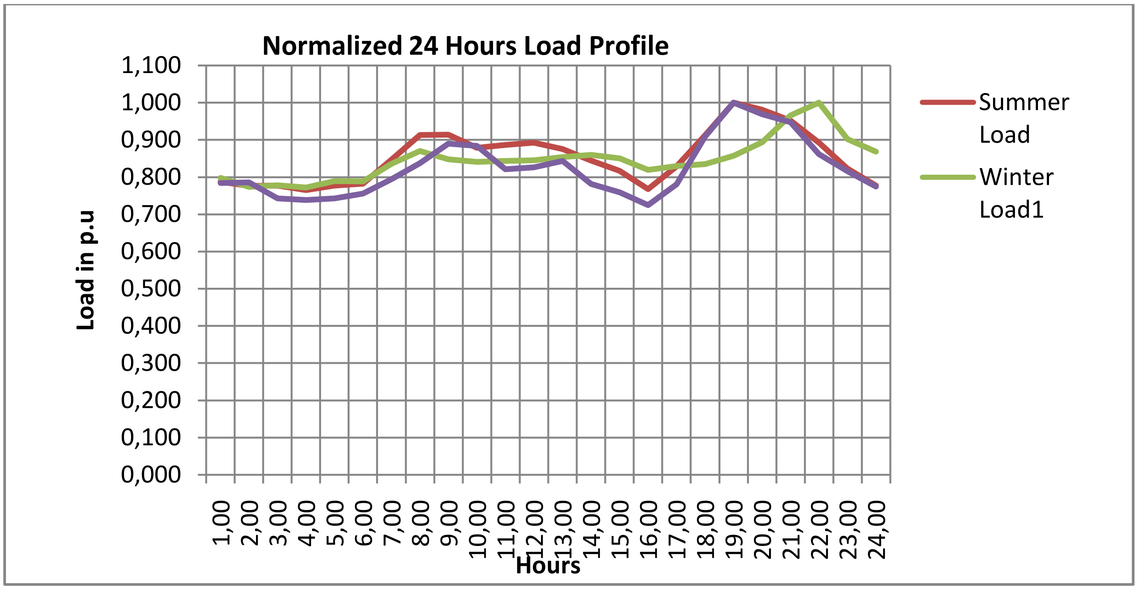


Figure 0.14 normalized load profile.

4.6.1. LMP for winter load

Since Bhutan is cold place, the load during the winter is much higher than summer. It can be seen from typical 24 hours winter load profile as below:

The Marginal costs of the generator bus in above are almost equal to cost model of generator current marginal cost. This is because the generator in all areas are available as a control and have not hit either its maximum or minimum limit.

4.6.2. Price Profile using LMP

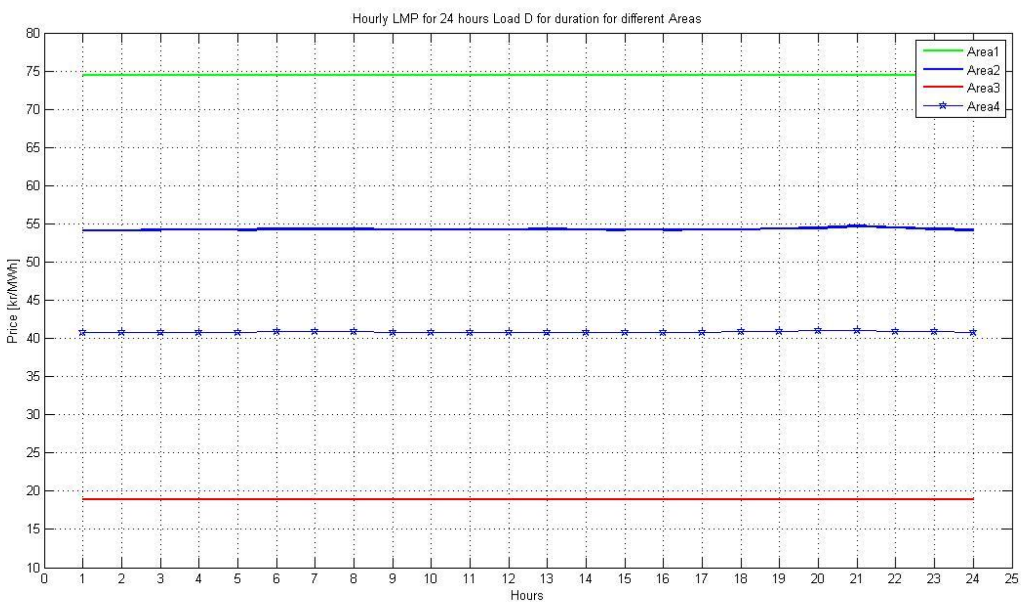


Figure 0.15 Hourly LMP for summer Load Profile

It can be observed that in LMP pricing scheme the different area pays different price of electricity as per the Locational Marginal Price of the area. The LMP in an area and every hour depend on the congestion of transmission network, total load and generation in the area. In that way it differs from Uniform Market price where all the area pays the uniform price for the electricity. And the price in uniform market price dependent on the hourly variation of load.

The LMP remains same for every hour in all the Area except for very small variation in Area 4. This indicates that there is no transmission lime bottleneck in the transmission system and the load is not really big enough to strain the system. The zoomed out LMP profile for Area 4 is given in Fig.4.16:

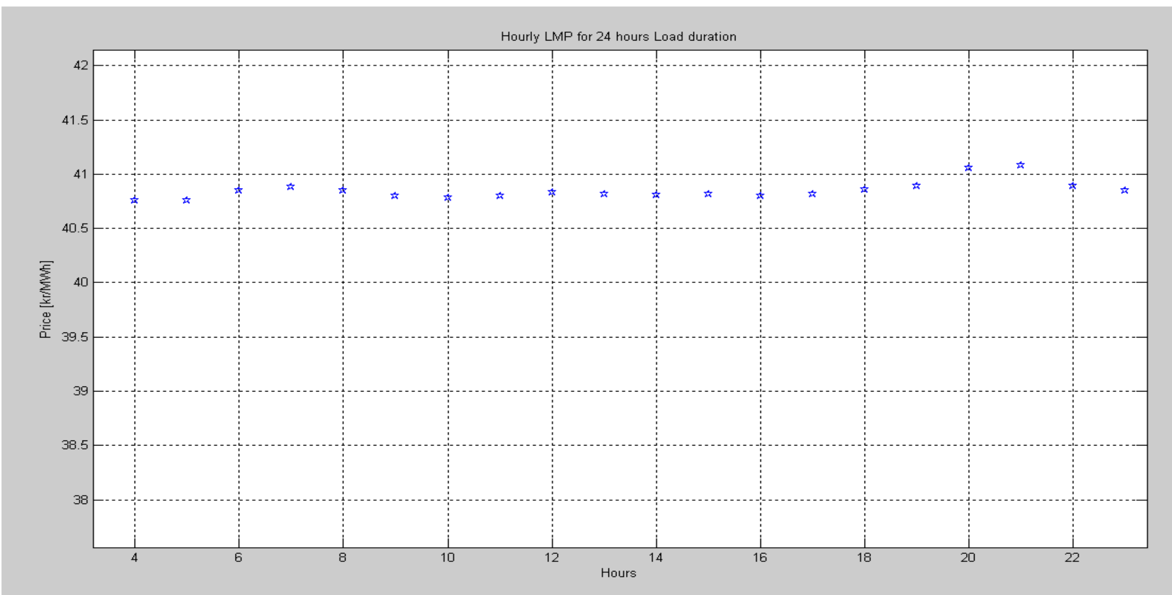


Figure 0.16 LMP variation (Zoomed out version) in Area 4.

LMP for winter load also show more or less the similar trend as the summer load. It is because there is no network congestion even during heavy winter load. The system remained unstrained.

4.7. Market Type II: Uniform Price Market

In order to maximize the social welfare in pool market, the elasticity of the demand is assumed. The customer benefit here can be defined as the benefit that customer receive from consuming the electricity and supplier benefit from selling the electricity in the pool market. The benefits can be calculated from the supply and demand curve and Market Clearing Price (MCP). Here MCP is the considered single price for all the market participants.

4.7.1. Single Auction Market

It is adopted in country like Australia and UK where the load forecast every five minutes is used to clear the quantity of supply bids in pool market [18].

Here only the GenCos submit their offers and it is stacked in increasing order of their bidding price. The demand is just a total aggregate load forecast. The market clearing price is obtained at the intersection point of demand forecast and the supply bid curve. Here the demand is cleared at single fixed price. The highest priced bid to intersect with the system demand forecast determines the market price. The objective function to maximize social welfare in this case would be concerned with lowering of cost of generation. As such it can be written as [16]:

$$Minimize, J = \sum_{i=1}^{n} BPS_i \times P_i = \sum_{i=1}^{N} f_i\ (P_i) \tag{4.2}$$

S.t. $\sum_{i=1}^{n} P_i - PD = 0$, which is demand-supply balance.

Where, BPS_i is the GenCos true marginal cost or bid cost of genco i.

4.7.2. Bhutan Case Model- BAU case.

4.8. Load Bid curve: Modeling of the demand side.

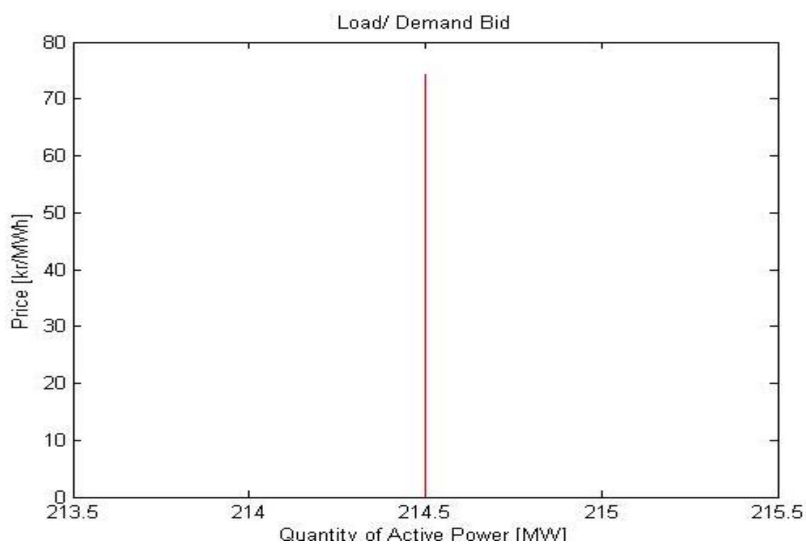


Figure 0.17 Aggregate Demand

- ***Generator Bid curve: Modeling of the supply side***

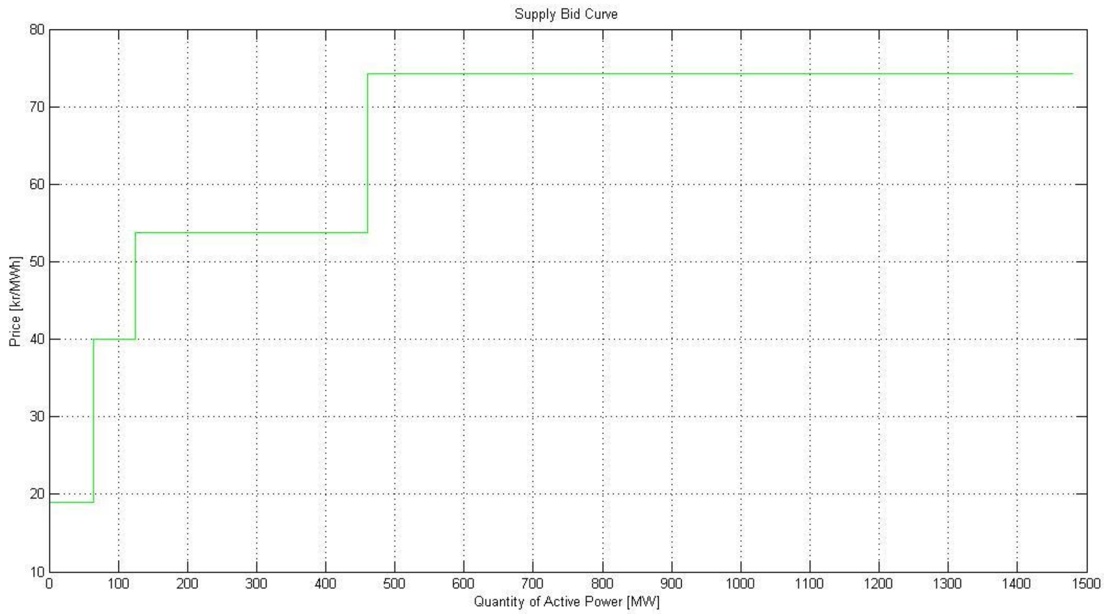


Figure 0.18 Generator bid curve

- ***Bidding curve to obtain market clearing price***

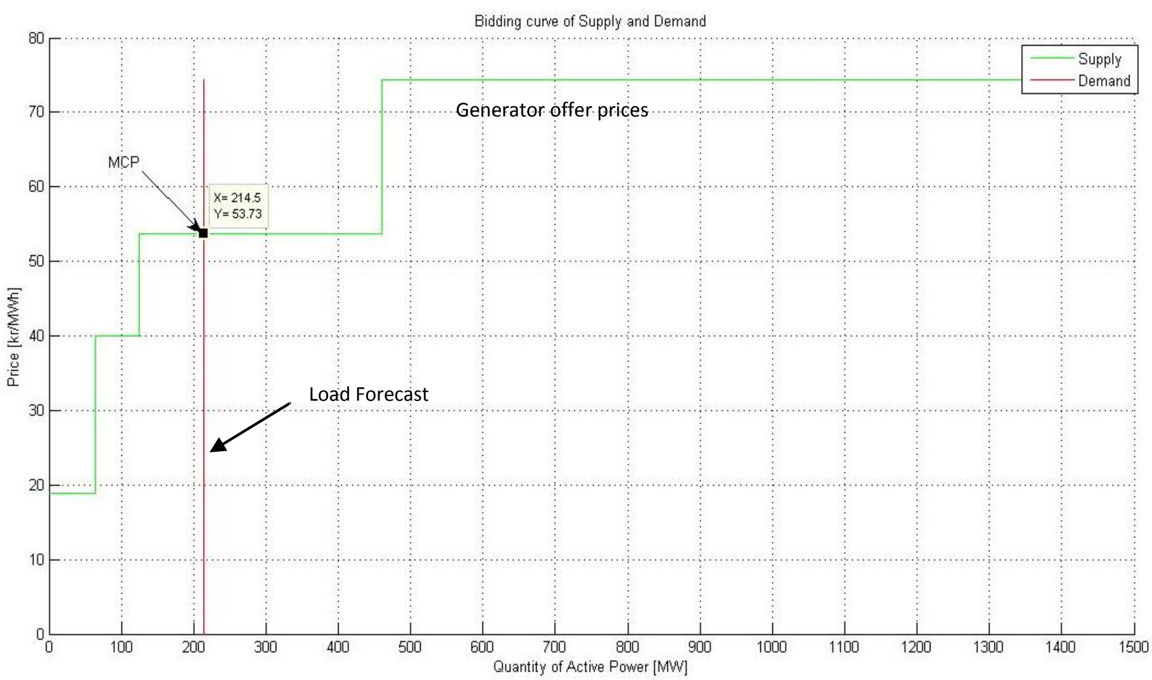


Figure 0.19 Load-Generator bid curve

The social welfare can be calculated from above as:

Minimize, J = $\sum_{i=1}^{n} BPS_i \times P_i = [(40 \times 18.92) + (60 \times 39.99) + (114.5 \times 53.73)]$

= 9308.285 million SEK.

Uniform Price Market comparison for different cases

In the Uniform Price Market, the transmission system is separated from generation. It does not take into account the constraints placed on transmission line like outage of critical line, violation of the transmission line limits. The only case which affects the clearing price is the quantity of load.

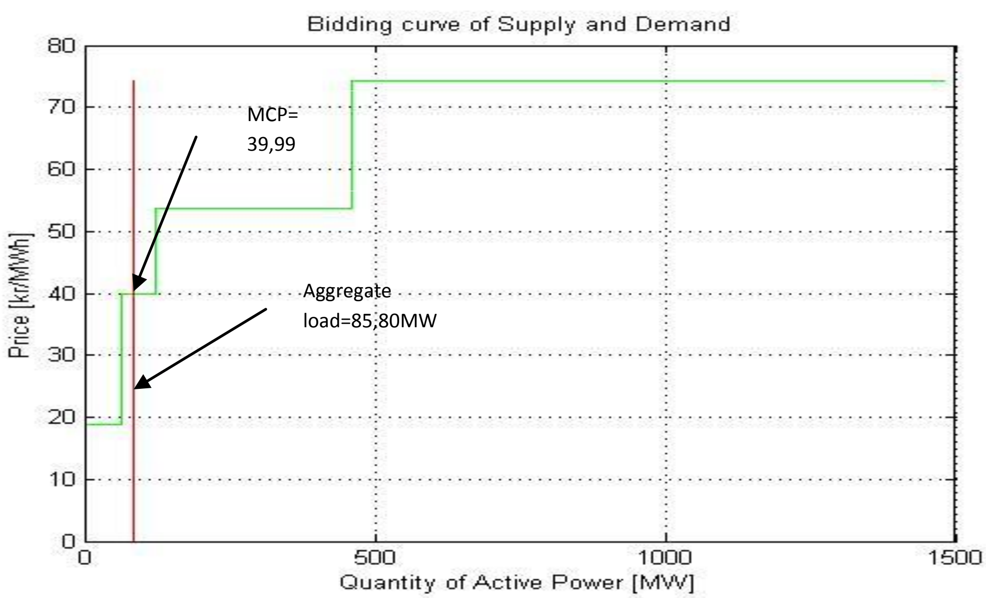


Figure 0.20 MCP at under decreased load condition

The MCP is now 39.99 Kr/ MWh. It has decreased compared to BAU case. If the load increases beyond 124 MW, the MCP will shift to next price level (same as BAU case) and further increase in load above 460 MW would see the maximum MCP.

4.7.3. Double Auction Market

In double Auction market both suppliers and buyers bid to sell and buy from the market pool. The supply bid is stacked in increasing order of its bid prices and buyers price in decreasing order of its bid prices. The system price or the market clearing price is obtained from the intersection of supply and demand curve**.** In this kind of market the demand cleared is variable [14],[20],[55],[56].

The attempt had been made to obtain double auction market for the proposed model. Due to lack of information of price signal from the demand side, the double auction model could not be created exactly for the competitive market model. It was at first tried by assuming that the "willingness of customer to pay" for the electricity as the existing electricity tariff. The load was then aggregated into different voltage level and then their bid price accordingly constructed. But it is found that the demand and supply curve fail to intersect. This is because the price customer is willing to pay is much higher compared to the bid price of generator (taken from the proposed model). Hence the market failed to clear.

The double auction market in Fig 4.21 is constructed assuming marginal price at load bus as demand bid price. It is to be noted here that the bid curve here is constructed just to get the feel of how double auction market would look like and how the market price is settled in case of elastic load. It is also to understand the calculation of total social welfare in double auction market.

The area under the supply and demand intersection curve is the social welfare.

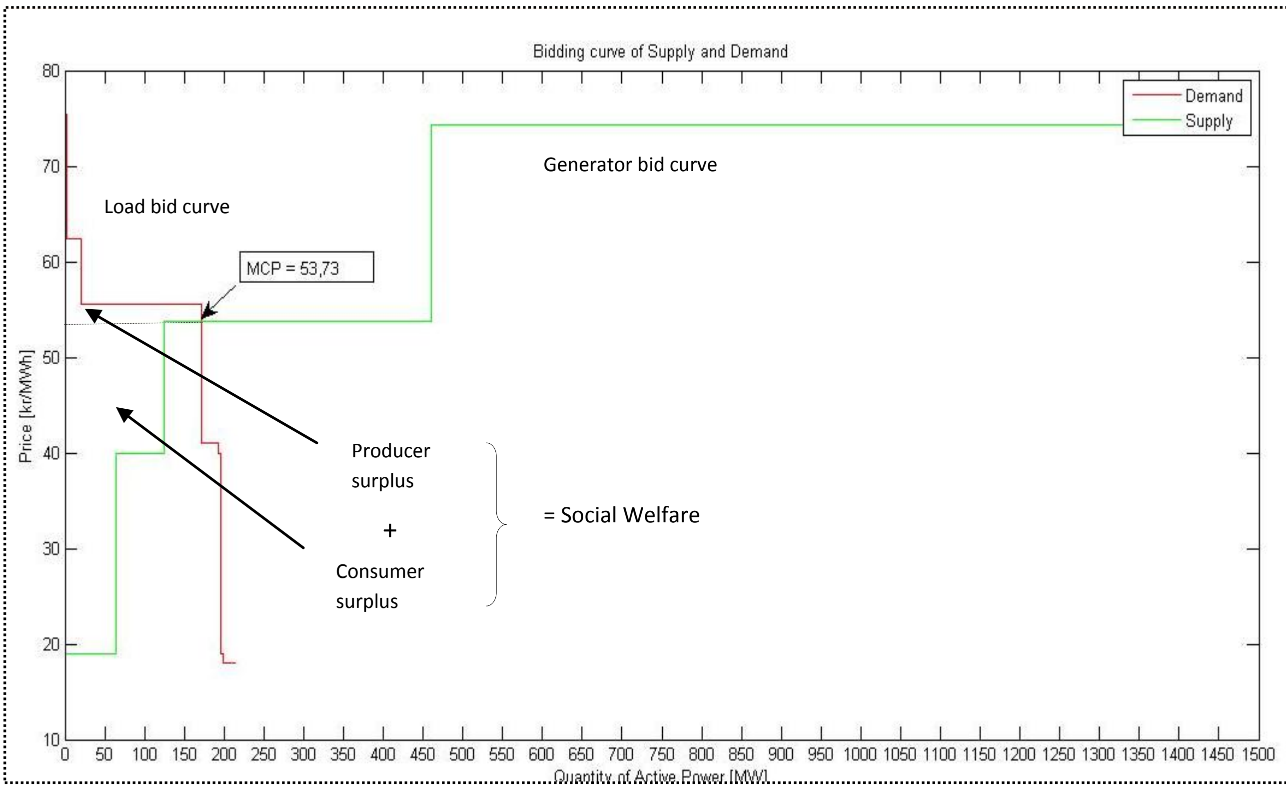


Figure 0.21 Demand-Supply curve and MCP in Double Auction Market.

The objective function of social welfare maximization based on Nodal price can be written as follow [49]:

Objective

$$f_n = \sum_{d}^{Nd}\{(bid\ price_d - nodal\ price_d) \times bid\ quantity\ d\} + \sum_{g}^{N_g}\{\text{nodal price}_\text{g} - \ offered\ price_g) \times offered\ quantity_g\} \tag{4.3}$$

Where, both nodal price_d and nodal price_g are positive values.

We can optimize the objective function in the following form due to its discrete bid blocks.

$$Max\left\{\overbrace{\left[\sum_{d}^{N_d}\sum_{db}^{N_{db}}((p_{db} - \rho_d) \times Q_{db})\right]}^{A} + \overbrace{\left[\sum_{g}^{N_g}\sum_{gb}^{N_{gb}}((\rho_g - p_{gb}) \times Q_{gb}\right]}^{\boldsymbol{B}}\right\} \tag{4.4}$$

Subjected to following constraints,

$$Max\left\{\overbrace{\left[\sum_{d}^{N_d}\sum_{db}^{N_{db}}((p_{db} - \rho_d) \times Q_{db})\right]}^{A} + \overbrace{\left[\sum_{g}^{N_g}\sum_{gb}^{N_{gb}}((\rho_g - p_{gb}) \times Q_{gb}\right]}^{\boldsymbol{B}}\left\{\left[\sum_{d}^{N_d}\sum_{db}^{N_{db}} Qdb\right] + P_l - \left[\sum_{g}^{N_g}\sum_{gb}^{N_{gb}}(\rho_{gb} \times Q_{gb})\right]\right\} = 0\right\} \tag{4.5}$$

$$P_{t,limit} - P_t \le 0 \text{ for t } \varepsilon\ N_t$$

$$0 \le Q_{db} \le Q_{db,max}$$

$$0 \le Q_{gb} \le Q_{gb,max}$$

Where, $\left[\sum_{d}^{N_d}\sum_{db}^{N_{db}} Qdb\right] = \sum_{d}^{N_d} P_d$

P_{db} : b_{th} block bid price of customer d
Q_{db} : b_{th} bid quantity of customer d
P_{gb} : b_{th} block offered price of supplier g
Q_{gb} : b_{th} block offered quantity of supplier
ρ_g : nodal price which supplier gets paid
ρ_d : nodal price which consumes pay
N_{db} : number of bid blocks of customer d
N_{gb} : number of offered blocks of supplier g
N_g : number of suppliers (generators)
N_b : number of customer (loads)
$Q_{db,\,max}$: b_{th} block limit of customer d.
N_t : number of transmission lines
$Q_{gb,max}$: b_{th} block offered limit of supplier g.
P_l : real loss in the system.
P_t : Power flow in transmission line t
$P_{t,\,limit}$: Power flow limit on transmission line t

Tabulation

Table 0.13 Social Welfare calculation for Double Auction Market

P_{db} (SEK/MWh)	ρ_d (SEK/MWh)	Q_{db} (MW)	ρ_g (SEK/MWh)	P_{gb} (SEK/MWh)	Q_{gb} (MW)	A = $\sum_{d}^{N_d}\sum_{db}^{N_{db}}((p_{db} - \rho_d) \times Q_{db})$	B= $\sum_{g}^{N_g}\sum_{gb}^{N_{gb}}((\rho_g - p_{gb}) \times Q_{gb}$	Social Welfare (A+B) in SEK/ MWh
75.50	53.73	3.00	53.73	18.92	64.00	65.31	2227.84	2293.15
62.34	53.73	18.00	53.73	39.99	60.00	154.98	824.4	979.38
55.55	53.73	151.50	53.73	53.73	60.39	120.78	0.00	120.78
						Total social welfare =		**3393.31**

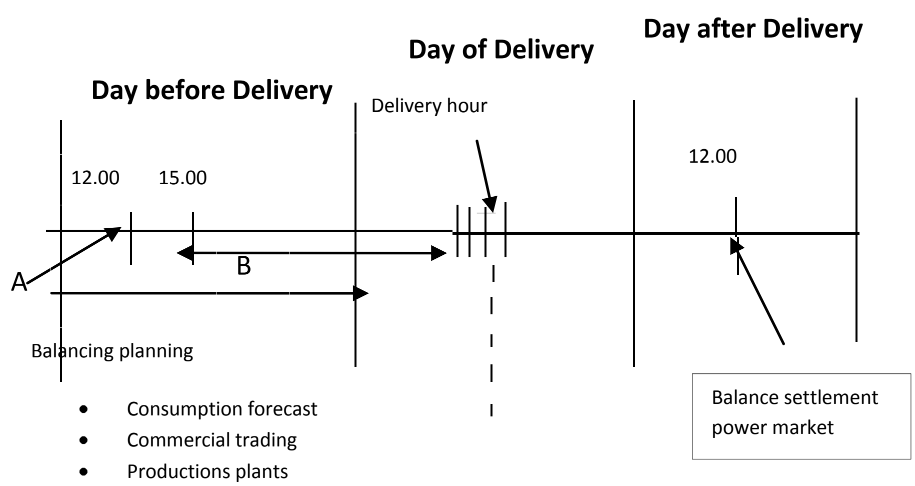
[Exchange rate, 1 Nu = 0.161669 SEK]

4.7.4. Day-Ahead market

- **NordPool's Day-Ahead market**

The players in Nord pool's Spot market are Sweden, Finland, Norway, Denmark and small area of Germany which entered the Nordic Electricity market in 2005.On Nord Pool's Spot market physical hour contract is traded for the following 24 hours which (midnight to midnight). NordPool also have internal adjustment market, Elbas. It acts like an electricity trading exchange as a single market place.

The auction is held daily and its spot market is closed for bids at 12.00. Supply and demand curve are constructed and the intersection point of the curves determines the system price and energy being traded. By 14.00 hours each day, NordPool informs the players about the price and quantity of energy that had been allocated for trading for next 24 hours. The information from the NordPool is submitted to their respective TSO (Svenska Kraftnat in Sweden). At 15.00 hours, spot market is closed and the market opens for trade for the coming power exchange. The hourly contract is also conducted but electronically and takes place up until one hour before delivery[58]



A. Spot market- Electricity spot. **B.** Balance Adjustment (Elbas) . **C.** Balance Regulation –Regulating power: i. automatic ii. sub ordered

Figure 0.22 Time line for trading and balance [58]

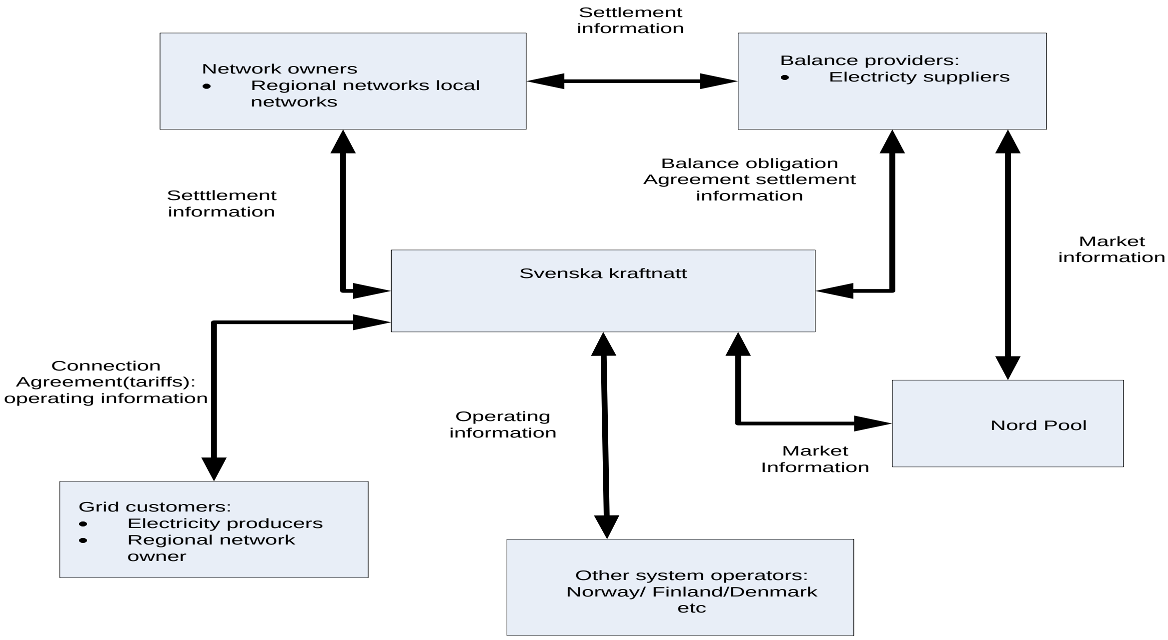


Figure 0.23 The network and the daily flow of information between the players of electricity market [58]

- ### Day-Ahead Market simulation for Uniform Price Market

The hourly market is simulated using the load profile in Fig. 4.13 & Fig. 4.14 .The Market Clearing Price (MCP) is obtained for d peak and minimum load of 136.84 MW and 81.539 MW respectively as shown in Fig. 4.24.

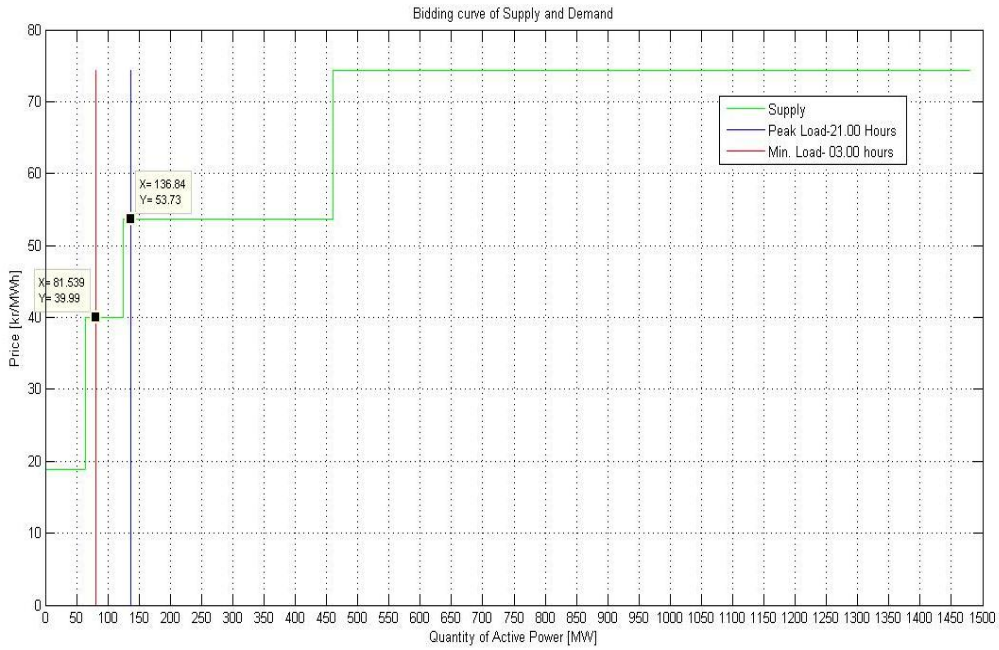


Figure 0.24 MCP for one hour (uniform market pricing)

Similarly clearing for all other hourly load, we get the hourly price profile as shown in Fig. 4.25.

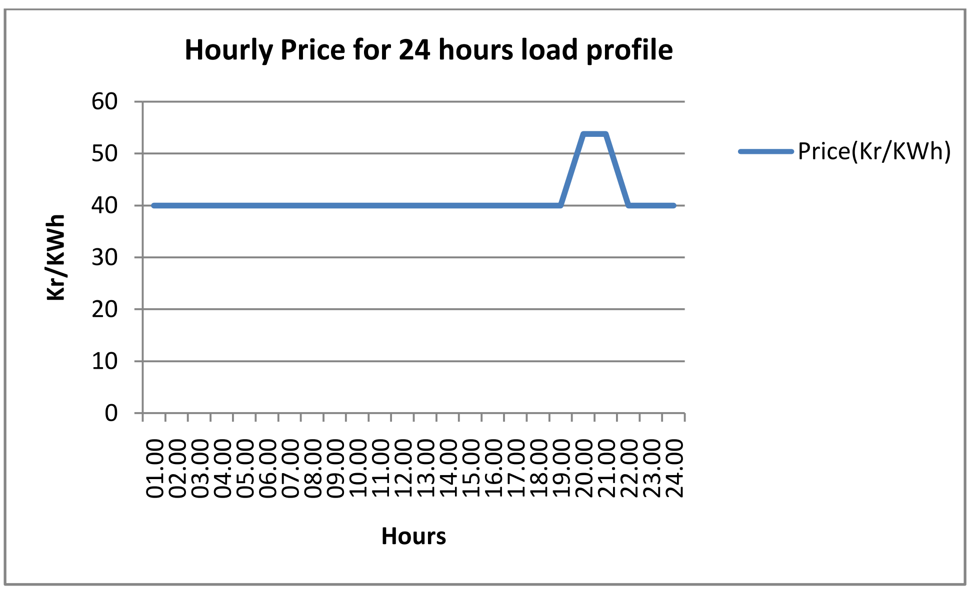


Figure 0.25 MCP profile for 24 hours (Uniform market price)

From the Fig. 4.25, the MCP obtained for all the hours is 39.99 Kr/MWh and 53.73 Kr/MWh during 20.00 and 21.00 hours which are peak load hours. The demand for energy is high during 20.00 and 21.00 hours due to the fact that, most of the people are home during that time and most of its electrical appliances and residential light is switched on. The industry load seems to be bit high for some and less for others.

4.8. Comparison between the existing system and the proposed market model

Table 0.14 Comparison of existing system with proposed market models

Parameters	Existing System	Proposed Market Model I	Proposed Market Model II
Total Cost of Generation	86179.66 SEK /hr	80782.96 SEK/hr	8611 SEK/hr
Market Price	0.182 SEK/kWh	0.071 SEK/kWh +(0.08) =0.158 SEK/kWh	0.053 SEK/kWh+ (0.08) = 0.142 SEK /kWh*
Total System Loss	14.05%	4.54%	Transmission system is separate. Loss cannot be calculated.

*It is spot market price plus transmission cost (existing charge) (1 US$ = 7.914 SEK)
-Loss % is calculated from generation and load details.

From the Table 4.14, it can be see that the competitive market brings down the average cost of electricity by 21% (including the existing wheeling charge) for uniform market pricing market and 13% in LMP based market as compared to the existing system 0.182 SEK/kWh.. This is because in competitive market, the GenCos have to sell their energy at its marginal cost of production and the profit margin has to be kept as minimal as possible to gain competitive edge over other suppliers in the market. Each generating unit is a price taker and not price maker in the competitive market. The total cost of generation also reduces relatively in the proposed model because it reflects the true cost of generation or supply cost of GenCos considering just the Operation & Maintenance cost, whereas in the existing system GenCos take into account lots of other cost components. This reflects one of the advantage of competitive market as it will lead to separation of generation cost from other associated costs, given in Equation [3.1]-[3.6].

The system loss in % is calculated by the Demand-Supply balance data. The loss % otherwise calculated by BPC takes into account total energy exported and imported also. The total loss is reduced to 4.54% in existing system.

4.9. Comparison of LMP based and Uniform Price Market

LMP based Market takes into account Generation Marginal Cost, Transmission Congestion Cost and Cost of Marginal losses.LMP is based on marginal cost of supplying next increment of electrical energy demand. LMP-based market is very location specific as where the demand is to be met accounting for both generator and network characteristics. It mirrors the healthiness of the total Power system. It can provide with valuable diagnostic information. LMP hence can be a strong economic indicator for generation capacity development and transmission congestion management and planning.

The problem with LMP based market is that there is significant opportunity to deviate from cost-based bidding and it opens the door for market power. .Under such circumstances, the consumers who are not responsible for congestion also end up paying extra for the congestion in the area. This on other hand can also provide incentives to build generating units in areas where there is generation shortage relative to demand.

In Uniform Pricing Market, it takes into account only generation and the transmission system is completely separated from it. It does not provide any information on transmission side regarding the stability or congestion of the network. It is a competitive market where the generator will be encouraged to bid as low as possible just keeping very minimum margin for profit. Uniform pricing market generally is fair and encourages competition in generation sector. Uniform market price can be used as an indicator for further investment in building generation plant. The total consumer benefit is much higher in this type of market. It is fair to consumer as they pay low prices as the cost of congestion in other areas is not distributed to them as in case of LMP based Market.

4.10. Which market model is suitable for Bhutan?

Bhutan is hydro-dominant country like that of Norway and Latin American countries. The Norwegian Development Agency (NORAD) and ADB are extensively involved in framing the regulation policy and frameworks in Bhutan. The deregulation might lead to having similar market model in future as that of Norway given the nature of generation.

Based on proposed model simulation, it is clear that Bhutan has no network congestion at present and it will not have that problem for some growth of load. There is no deficit in generation side either. Most of the power generated is exported to India through bilateral contract signed between two countries.

But to bring down the cost of generation, competitive market needs to be established. The simulation of proposed model of Bhutan Power system in Power World clearly brings out the advantages. The market price is reduced to half of the existing price in competitive market as generator has to bid at its marginal cost of production. For the existing Bhutan Power Sector, Uniform Price Market is found suitable. The competitive market will help bring down the cost of generation and improve efficiency of generation through competition. GenCos in Bhutan can also participate in Uniform Price Market of neighboring state in India in future.

The establishment of competitive market in Bhutan will need to address the following issues:

- It should have properly regulatory framework and bodies in place for IPP participation and other market participants which is non-existing at present.
- It should keep track of demand-supply pattern in neighboring countries .With very low domestic consumption, majority of the electricity need to be traded with neighboring countries. Since Bhutan has very ambitious hydro-project development plans in pipeline, it should be wary of over-production to avoid "boom and bust" cycle which is one of the risk of liberalized market,
- The transmission network in Bhutan need to be strengthened and expanded further for providing an open access to market participants. The ancillary service market could also play a vital role here. Bhutan should encourage private participation in other renewable energy beside hydro like wind and solar.
- Need to restructure the power sector at distribution level also. Transmission System Operator should be left for facilitating open access indiscriminately and maintaining network for energy transaction.
- Bhutan is hydro-dominant country. The availability of energy is subjected to seasonal variation which means it will be left with acute power shortage during dry season. Bhutan imports energy from India during winter and ironically the demand for energy is much higher during that time due to cold climatic condition. Bhutan should also make provision for building reservoir dam and not just run-off river scheme as it exists just now.
- In order to facilitate competitive market, it will need to gradually phase out subsidies as it hides the true price signal and social problems.
- Industrial development in the country should match with the growth of generation sector in the country.

CHAPTER 5: TECHNICAL CONSIDERATION FOR A COMPETITIVE MARKET FUNCTION

This chapter brings out the supporting tools that are needed in a deregulated market environment. It focuses on congestion management and ancillary services.

5.1. Privatization

The introduction of competition is always accompanied by privatization of publicly owned utility. It is one of the most important reforms needed for competitive market. Privatization would mean selling off part or all of publicly owned utility to private investors. These will encourage private participations and competition bringing down cost and increasing efficiency of the system.

5.2. Need for an Independent System Operator (ISO)

With unbundling of generation from transmission sector in a competitive market, generation sector will be become fully competitive with many market participants whereas the transmission system remains regulated monopoly and it will be necessary to provide non-discriminatory and open access to all the market participants through planning and operation of power transmission system. It is also important to ensure reliability of the network in its region of operation. This function can be implemented by entity called Independent System Operator (ISO)[59]

The function of ISO at various size and scale is given in the Fig. 5.1.

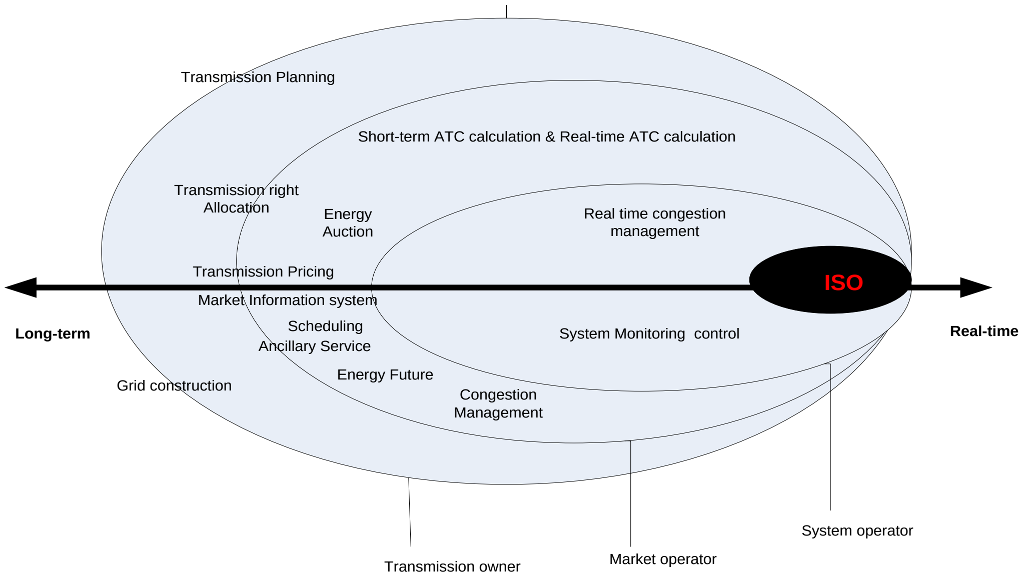


Figure 0.1 Function of ISO at various size and time scale [57]

5.3. Network Management Issue

In deregulated environment, it is very important to have safe and reliable power system network. Some of the issues pertaining to it are discussed below:

5.3.1. Congestion Management

In deregulated market, there is increase in production and consumption of energy. This will lead to operation of transmission network beyond one or more of its transfer limit (Thermal, Voltage & Stability limit), then the network is said to be congested. The maximum amount of additional MW that can be transferred from one part of power system to another without violating the stability limit is called Available Transfer Capability (ATC). It is evaluated based on its most limiting factor. In this case mostly voltage stability limit is taken into account.

If the ATC calculated indicates that the network is congested, then how will the market be settled? The market settlement under congested network is different in different countries. Here the attempt is made to study some of the congestion management method with regard to Nordic countries (Norway and Sweden in particular) and North America.

- **Price Area Based Congestion Management**

It is also called "market splitting". Here the bid areas have different price after the market settlement called "price areas" This method is being used in Norway to settle market whenever there is congestion. The congested network is separated into different bid areas by separate corridor by the ISO prior to the spot market bidding. When bid areas are declared, each bidder submits separate bid for each area. Larger bidder must separate their bid by area and if the bidder has both generation and load in the same area, it is not required to submit separate bid. The spot market is initially resolved assuming no congestion and generation and load in each area is determined. If transfer in bid areas does not exceed the limit, one system-wide market price is used. If the transfer exceeds it limit, each area is separately settled using the bid for that area and transfer constraint. This lead to the decrease in price in excess generation area, reducing the generation while increasing the load in the area. On the other hand, there is increase in price in excess load area where the generation is increased and load is decreased. This is done until the transfer constraint/limit is satisfied. ISO receives congestion income called congestion rent. The price area can be mathematically expressed[47] as below:

Area price in low price area (generation surplus)

$$\rho_{AREA}^{low} = \rho_M - \Delta\rho \tag{5.1}$$

where, ρ_M is unconstrained MCP

Area Price in the high price area (generation deficit),

$$\rho_{AREA}^{high} = \rho_M + \Delta\rho \tag{5.2}$$

- **Counter –Trade (Buy Back Method)**

It is trading in opposite direction to an existing trade that is causing transmission congestion. It is practiced in Sweden and Finland. Counter-Trade method is used during operation phase as in during real-time operation. If there is congestion, ISO will order increase or decrease of generation depending on the load demand and the re-scheduling is called by ISO from the bids in the regulating market. The ISO selects the lowest cost block of energy to buy or sell necessary to resolve congestion. The highest cost block selected during each hour of operation determines the regulating market price for buyers and sellers. The cost of the counter-trade is charged to ISO which signals the need for network reinforcement [20], [67].

- **Firm Transmission Right (FTR).**

This method is used in North America. The congestion charges are based on Locational Marginal Price (LMP). In this approach, users who contribute towards congestion are penalized and those who alleviate congestion are rewarded. LMP is used to charge for congestion fees which is positive when the transfer causes congestion and vice versa. The hourly congestion charge for transferring P MW between point A and B is given as below[59]:

$$\text{Congestion charge} = P \times (LMP(B)\text{-}LMPC(A)) \quad (6.3)$$

FTR is a purchased right that can hedge volatile congestion charge by buying the right to transfer the amount of power over a constrained line between two nodes at fixed price and it is directional to the power flow. If the FTR holder violates the direction of Power flow, they will be penalized. Each FTR holder receives a congestion credit based on preferred schedule as below:

$$\text{FTR credit} = \text{Amount of FTR} \times (LMP(S)\text{-}\ LMP(E) \quad (6.4)$$

Where, LMPS(S) and LMP (E) are staring and ending point of FTR respectively.

5.3.2. System Security

It is defined as an ability of the system to respond to dynamic or transient disturbances arising within the system [20]. The system security in deregulated environment can be provided as below:

- **Spinning Reserve**

Spinning reserve is used to maintain the frequency stability during the emergency and unforeseen load swing conditions**.** It is online reserve capacity which is synchronized to grid and called within 10 minutes by ISO to meet the imbalanced demand. Usually ISO requirement of spinning reserve is 50% of the operating reserve.

The main reason for keeping the provision of spinning reserve is for the system to recover quickly from loss of generation usually during contingency.

5.3.3. Ancillary market in different countries

- **Sweden**

The ISO, Svenska Krafttnat regulates both the reserve and regulation market. It does not pay for reactive power to generator and load shedding is recognized as an ancillary service but it is not compensated. Svenska Krafttnat purchase long term contract from generating companies for primary frequency regulation whereas the secondary frequency regulation is done through *balance service or market*. Depending on the frequency, the up or down bid regulation from the bidders (GenCos and Large utilities) is bought by ISO from the balance market. The up or down regulation bid is as shown in Figure 5.2.

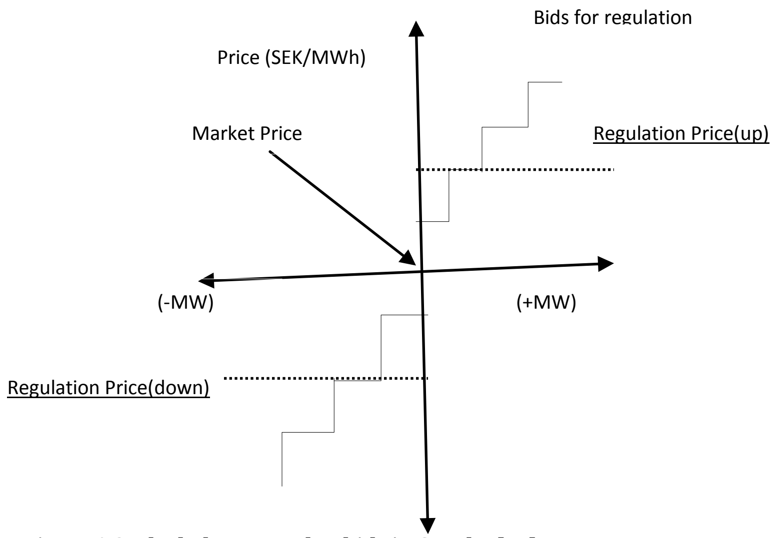


Figure 0.2 The balance market bids in Sweden[47]

- **Norway**

Since Norway is hydro-dominated country, the Norwegian generator is required to reduce the turbine regulator droop to 6 % due to increased Ancillary service obligation. Thus utilization of capacity margins in spinning reserve in hydro units operated at best point is sufficient for frequency control and disturbance. If more reserve is needed TSO can ask its Norwegian generator to set its droop characteristics at higher level and they are compensated for it. The Norwegian TSO, Stattnett have one year contract for it with 40 generators for maintaining primary reserve.

Balancing market is procured through Regulating Power Market (RPM). It is open to generator and customer (large industrials) which are able to respond to 15-minute notice with an uninterruptable power activation of at least one hour. The RPM price is determined by frequency regulation. In upward regulation, the most expensive bid utilized is price setting and in downward regulation the most inexpensive bid utilized is price setting.

Reactive power is provided by connection/ disconnection of capacitor batteries and static phase compensation (SVC plants). It is also compensated by connection-disconnection of transmission lines and under/over magnetization of generation units.

- **North America**

Regulation under automatic generation, Synchronized Reserve, Non Synchronized Reserve, Operating reserve is common type of ancillary service used. It can be Forward Ancillary Service Market

(ASM), the near time ASM or Real time ASM. Resourced that meet day ahead Ancillary Service market is used in real time day ahead and real time delivery requirement. Ancillary market is under the framework of Standard Market Design with LMP as its key concept [49].

5.3.4. Power balancing

- **Reactive Power and voltage control services**

In order to maintain the reactive power balance and voltage within its stability limit, reactive power sources including generating units need to be called upon for the requisite service. This stability constraint also limits the amount of power that can be transferred securely along the transmission network and corridor. Availability of the sufficient amount of reactive power is limited by the operational limits specified by the generating unit capability curve.

Sometimes the generating unit has to reduce/curtail its active power generation so as to allow the required change in reactive power (Vars) once the reactive power limit is reached, in such cases generating should be paid remuneration for its lost opportunity cost.

Other technique for compensation of reactive power in transmission line is by using switched elements called static compensation. It increases the voltages at node. The variable compensation is also carried out by the use of latest art of technology using power electronics devices called Flexible AC Transmission System (FACTS). The FACTS device help improve stability by controlling the following parameter [56] as shown in Fig. 5.4.

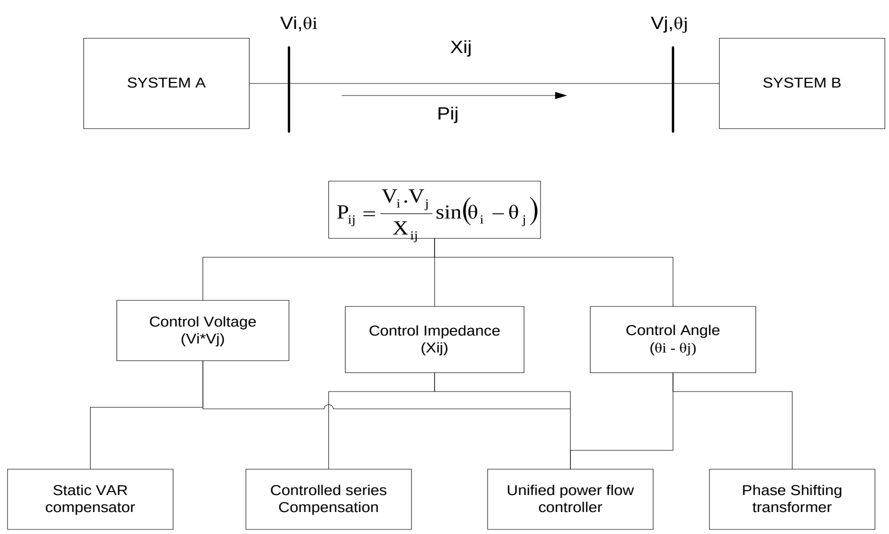


Figure 0.3 Variables controlled by FACTS device.

In the deregulated environment, the value of a reactive power support service has no direct relationship with its actual cost. Rather its value should be assessed under normal and emergency condition. It is also called Cost-Benefit Analysis.

5.4. Communication System

It is very important to have good communication system to support the bidding in spot market. The internet based system that could exchange information among market entities, system coordinator and security coordinator will be necessary . The need to exchange commercial and operating information among different players in the market have increased in electricity trading. The market participants also use various forecasting tools and techniques for spot market price which form a part of Distributed Energy Management (DEM) computer system.

Nordpool posts the market data like spot price and power transaction information on its webpage making information available to all the participants in real-time.

CHAPTER 6: CONCLUSIONS AND FUTURE WORK

This Chapter concludes the thesis work with the key findings and recommendation. The thesis work is also left open for future improvement and works.

6.1. CONCLUSIONS

The deregulation process and evolution of competitive market in different parts of the world is studied. The different market models being practiced in these countries had also been bought out. It is evident that deregulation of electricity market have become a global trend. The deregulation is 100% complete and is very successful and exemplary in Nordic countries, England, Germany, France, North American and Australia. Those countries which are still under the process of reforming their electricity market can learn lots from successful market established by these countries. For example the power crisis in California in 2000 highlighted the need for strong regulatory bodies in place before opening of competitive market otherwise it will lead to the abuse of market power. Bhutan also felt need for restructuring its power sector by following the best practice adopted in the world with financial funding and technical expertise help from ADB. The restructuring of power sector already saw many benefits in terms of power system stability & reliability and electric connectivity have also improved thereby increasing the living standard of people. The main goal of deregulation for Bhutan electricity industry is to attract IPP for investing in building hydro-plants and establishing competitive market in future.

In this thesis the whole Bhutan Power System was built and simulated in Power World Simulator and the market model is developed by dividing the system into four Areas with generating unit and loads. The model is tested for OPF-based and Uniform Price market structure for Day-Ahead Spot Market. The market is also experimented on the model for various contingency cases like outage of critical transmission line, loss of cheap generating unit, violation of transmission limit, increased or decreased in load. From the simulation and analysis, it is found that the price of electricity reduces comparatively in competitive electricity market. The average market price came down by 21% (including the existing wheeling charge) for uniform market pricing market and 13% in LMP based market as compared to the existing system 0.182 SEK/kWh. The network loss calculated taking supply-demand balance in the existing system is 14.7 % and the loss reduces to 4.54 %. The total generation cost is reduced in competitive market too. The Day-Ahead Spot market for both winter and summer load showed very small or almost no changes in price for hourly variation of load in both Uniform and LMP based Market.

The competitive market structure found suitable for present situation in Bhutan from the simulation and analysis of market model is Uniform Price Market. Bhutan power system network does not have congestion problem in transmission network at the moment. During the OPF study of the proposed model under different contingency case, it can be concluded that even with some growth in load in future, it would not impose any constraints on the network. But to ensure security and stability of power system in future, investment on ancillary service for congestion management is must. It is very important that it is fully equipped before it opens for competitive market. It also calls in for establishment of ISO, privatization of publicly owned utility and good communication services.

The Power market should be left on its own with freedom to choose and experiment with new technologies for better change but with proper regulation. The tight grip on Power market by the government would mean regulating the power-dependent industries. The present reform scenario looks promising for deregulation in Bhutan. It can also to play important role as main supplier of electricity in SAARC countries once the much-hyped about SAARC energy ring is established

6.2. Future Work

The model developed in this thesis does not claim to be 100% accurate and nor does it claim to be the perfect model for competitive market within Bhutan. It can serve as a basis for the establishment of competitive market model in Bhutan. Thus, there is huge scope for future work and improvement on this model. This model can be simulated for Reactive energy market which could not be under-taken in this thesis due to lack of time. The model can also be updated by including the generating plants, new transmission lines and other power system components that might be added on existing system to get better result. The calculation for difference in congestion cost for LMP-based market can also be taken up for future work using the model.

There is wide range of areas in power market that could be taken up. The risk of hydro-dominated electricity market and different method of hedging the risk can also be formulated pertaining to Bhutan network. The ancillary service and its market is also another important and interesting issue that can be looked into. The model can be modified and used to study the Uniform Price Market by including India and other neighboring countries similar to Nordpool market design.

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APPENDIX A: Load growth pattern in Bhutan

A1: Load Growth in west and East Bhutan 2007-2008

The growth of load in Western and Eastern Bhutan in the year, 2007 -2008 is given in Fig. A1.1

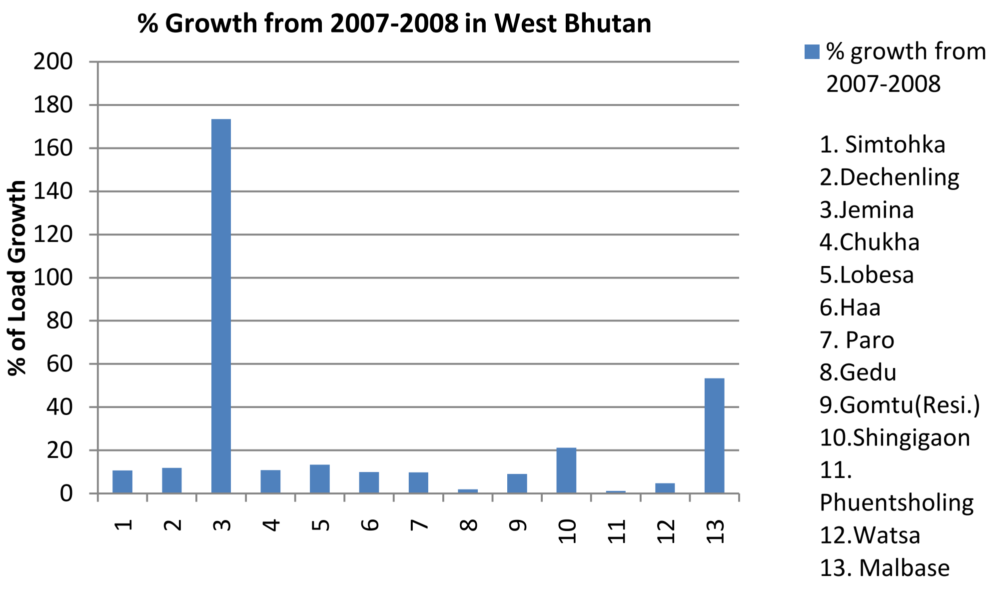

Fig. A1.1 The load growth in West Bhutan the year 2007-2008

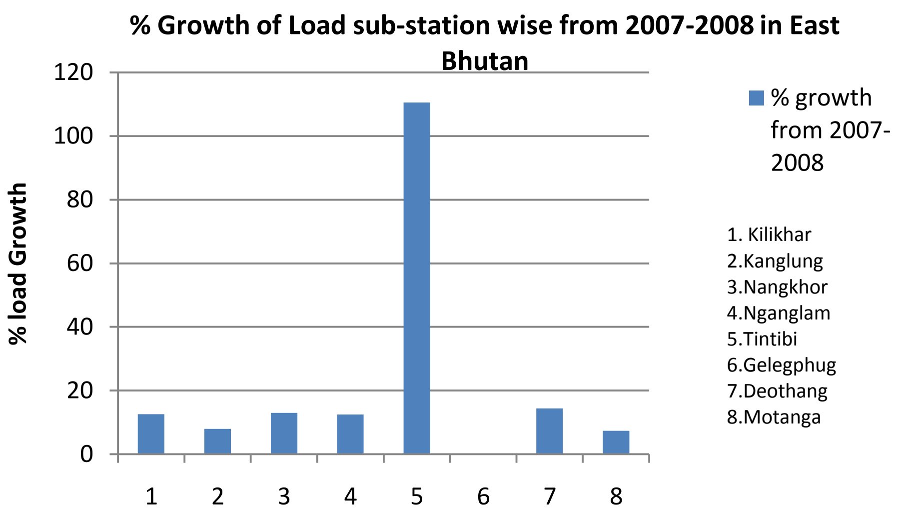

Fig. A1.2 The load growth in East Bhutan the year 2007-2008

A2: Load Forecast by DOE

The load forecast by Department of Energy (DOE) till 2017 is given in Fig. A2.1

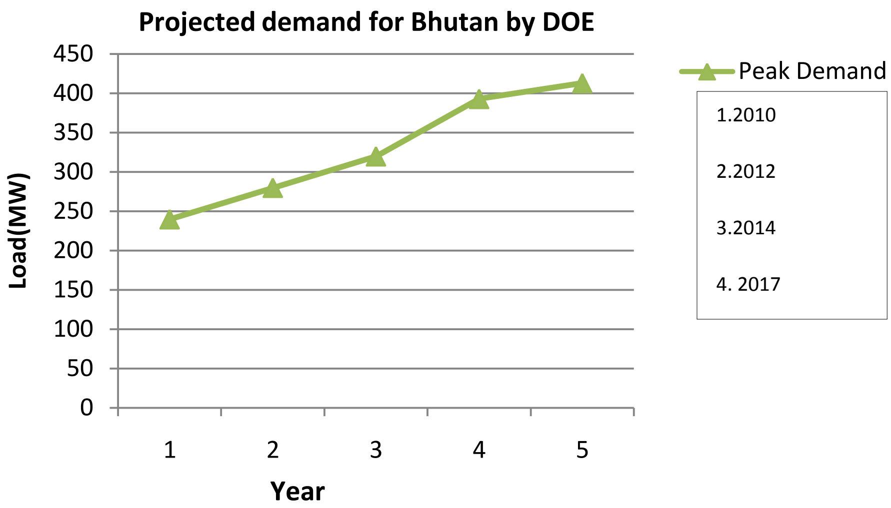

Fig. A2.1 The load growth in East Bhutan the year 2007-2008

APPENDIX B: Comparison of electricity tariff in different countries

B1: A comparative table of residential electricity tariff in different countries is given in Table B1.1

Table B1.1 Global electricity Tariff [42]-[53]

Country	Electricity Tariff (US$/ kWh)	Remarks
Denmark	0.230	As of 2006-2007
Sweden	0.066	As of 2006-2007
Finland	0.069	As of 2006-2007
Norway	0.068	As of 2009
Germany	0.131	As of 2006-2007
France	0.085	As of 2006-2007
Iceland	0.116	As of 2006-2007
Italy	0.367	As of 2006-2007
Netherland	0.126	As of 2006-2007
USA	0.093	As of 2006-2007
Canada	0.062	As of 2006-2007
UK	0.111	As of 2006-2007
South Africa	0.035	As of 2006-2007
Australia	0.096	As of 2007
China	0.077	As of 2009
Japan	0.183	As of 2007
Thailand	0.091	As of 2007
South Korea	0.110	As of 2007
Singapore	0.145	As of 2009.
Vietnam	0.049	As of 2009
India	0.044	As of 2008
Nepal	0.095	As of 2008
Bangladesh	0.048	As of 2008
Pakistan	0.048	As of 2008
Sri Lanka	0.089	As of 2008
Bhutan	0.030	As of 2009

APPENDIX C: Bhutan Power System Data

C1: Generation details

The total active and reactive power ratings of generators in different generating station are given in Table C1.1.

Table C1.1: Major Generating stations

SI.No	Generating station	No of Units	Installed capacity in MW	Reactive Power Rating	Total capacity in MW
1	Tala	6	170	100 Mvar	1020
2	Chukha	4	84	45 Mvar	336
3	Basochhu	2	20	6 Mvar	40
4	Rurichhu	2	12	10 Mvar	24
5	Kurichhu	4	15	8 Mvar	60
6.	Mini./Micro	-	-		8.068
	Total				**1488.068**

C2: Substation Load data.

The load data in each substation in Bhutan for winter and summer is given in Table C2.2.

Table C2.2: Load / Demand in Summer and Winter in Bhutan as of 2009.

Sl#	Loads	Present Winter Load	Present Summer Load
1	Chukha Load	3.5	1.75
2	Singload	8	8
3	BFAL Industrial	40	40
4	BCCL Industrial	23	23
5	Paskha Industrial	50	50
6	Gedu 33kV	5	2.5
7	DrukIron Industrial	6.7	6.7
8	PCAL Industrial	10	10
9	Sipsoo	1.5	0.75
10	Watsa	1	0.5
11	Haa	2.5	1.25
12	Paro 11kV	3	1.5
13	Jemina	1.5	0.75
14	Olakha	2	1
15	Semtokha	16	8
16	Decholing	12	6
17	Lobeysa	3	1.5
18	SDEBF Industrial	19	9.5
19	Dewathang	2	1

Sl#	Loads	Present Winter Load	Present Summer Load
20	Ngankor	1	0.5
21	Ngalan	0.8	0.4
22	Tintibi	1	0.5
24	Kilkhar	2	1
25	Kanglung	2	1
26	Singh Industrial	3	3
27	Pling Industrial	5	5
28	Gomtu33kV	4	4
29	Gomtu11kV	2	1
30	Paro11kv	4	2
31	Olakha33kV	3	1.5
32	Lobeysa11kV	2	1
33	Chukha Internal	3.5	1.75
34	Basch11kV	2	1
35	Trongsa	2	1
36	Bumthang	3	1.5
37	Tsirang	1	0.5
38	Gedu11kV Load	3	1.5
39	Gomtu11kV Loaddoms	1.5	0.75
	Total	**255.5**	**202.6**

C2.3: Transmission Line data

The transmission line details of Bhutan Power system network is given in Table C2.3.

Table C2.3: Transmission Lines

Sl. No.	Location	Dzongkhag	Voltage Level (kV)	Length of line (km)	Type of Conductor
A) 66 kV Transmission Lines					
1	Semtokha - Lobesa	Thimphu/Wangdue	66	24,33	Dog
2	Lobesa - Rurichu	Wangdue	66	20,80	Dog
3	Hebisa - Rurichu	Wangdue	66	3,12	Dog
4	Chukha - Chumdo	Chukha/Paro	66	36,70	Dog
5	Chumdo - Olakha	Paro/Thimphu	66	18,30	Dog
6	Olakha - Semtokha	Thimphu	66	1,63	Dog
7	Chumdo - Paro	Paro	66	24,00	Dog
8	Chumdo - Haa	Paro/Haa	66	33,52	Dog
9	Tie-line - Watsa	Chukha	66	0,50	Dog
10	Chukha - Gedu	Chukha	66	20,10	Dog
11	Gedu - P'ling	Chukha	66	17,18	Dog
12	P'ling - S'goan	Chukha	66	8,38	Dog
13	P'ling - Gomtu	Chukha/Samtse	66	27,35	Dog
14	Kasadrapchu - Jemina	Thimphu	66	6,14	Dog
15	Semtokha - Dechencholing	Thimphu	66	11,90	Dog

Sl. No.	Location	Dzongkhag	Voltage Level (kV)	Length of line (km)	Type of Conductor
16	Malbase - Pasakha (multi ckt)	Chukha	66	3,45	Panther
	Total			**257,40**	
		B) 132 kV Transmission Lines			
1	Gyelpozhing - Kilikhar	Mongar	132	10,24	Panther
2	Kilikhar - Kanglung	Mongar/Trashigang	132	29,81	Panther
3	Kilikhar - Tangmachu	Mongar/Lhuentse	132	43,10	Panther
4	Gyelpozhing - Nangkor	Mongar/P'gatshel	132	33,59	Panther
5	Nangkor - Deothang	P'gatshel/S'jongkhar	132	23,52	Panther
6	Nangkor - Nganglam	P/gatshel	132	34,30	Panther
7	Nganglam - Tintibi	P'gatshel/Sarpang	132	83,20	Panther
8	Tintibi - Gelephu	Sarpang	132	46,00	Panther
9	Gelephu - Border	Sarpang	132	1,00	Panther
10	Deothang - Motonga	S/jongkhar	132	10,50	Panther
	Total			**315,26**	
		C) 220 kV Transmission Lines			
1	Chukha - Thimphu	Chukha/Thimphu	220	54,36	Zebra
2	Rurichu - Semtokha (S/C)	Wangdue/Thimphu	220	36,43	Zebra
3	Chukha - S/Goan (S/C)	Chukha	220	31,48	Zebra
4	S/Gaon - Birpara (S/C)	Chukha	220	2,50	Zebra
5	Chukha - Birpara (D/C)	Chukha	220	35,43	Zebra
	Total			**160,20**	
		D) 400 kV Transmission Lines			
1	Tala - Khogla - Siliguri	Chukha	400	24,62	Moose
2	Tala - Pugli - Siliguri	Chukha	400	49,53	Moose
	Total			**74,14**	

APPENDIX D: Power Market Model Simulation data.

D.1: OPF Bus record

The OPF result of Buses of the simulated market model is given in Table D.1.

Table D.1. OPF Bus Record of simulated market model

OPF Bus Records				
Bus No.	**Bus Name**	**Area Name**	**MW Marg. Cost**	**Mvar Marg. Cost**
1	chukha2	Area2	53,73	-0,08
2	chukha11	Area2	53,73	PV Bus
3	chukha6	Area2	53,57	-0,24
4	Gedu6	Area2	54,37	0,31
5	chumdo6	Area2	55,42	1,05
6	khasjun6	Area2	55,47	1,1
7	Malbase2	Area1	74,52	0,07
8	Malbase6	Area1	74,42	-0,02
9	Pasakha6	Area1	74,71	0,07
10	Snhgnh6	Area1	74,6	0,04
11	Shingaon2	Area1	74,57	0,09
12	shingagon6b	Area1	74,57	0,09
13	pling6	Area2	54,55	0,5
14	Gomtu6	Area2	59,95	3,73
15	Samtse6	Area2	60,14	3,82
16	simtokha2	Area3	18,97	-0,03
17	Simtokha6	Area3	18,98	-0,02
18	Lobesa6	Area3	19,03	0,01
19	Rurichu6	Area3	18,9	-0,09
20	Rurichu2	Area3	18,92	-0,08
21	Basochu6	Area3	18,91	-0,09
22	Basochu11	Area3	18,91	-0,09
23	Malbase4	Area1	74,38	0,01
24	Tala4	Area1	74,32	-0,01
25	Bipara2	Area2	53,63	-0,06
26	Tala1	Area1	74,32	PV Bus
27	Binaguri2	Area1	74,25	-0,14
28	Eqvt. Indian	Area1	74,4	Slack Bus
29	Binaguri4	Area1	74,39	0
30	Rangla1	Area4	41,7	-0,14
31	Motangla1	Area4	41,55	0,19
32	Dewathang1	Area4	41,34	0,18
33	Nangkhor1	Area4	40,87	0,13
34	Nganaglam1	Area4	41,05	0,14
35	Tintibi1	Area4	41,45	0,09
36	Jemina1	Area4	41,55	-0,01
37	Gelegphu1	Area4	41,6	-0,07
38	Salkata1	Area4	41,7	-0,19
39	Kurichu	Area4	39,99	PV Bus
40	Kilikhar1	Area4	40,01	0,01
41	kanglung1	Area4	40,03	0,02
42	Salkata2	Area4	41,66	-0,21