Pricing Mechanisms of Electricity in SAARC Member States

SAARC ENERGY CENTRE

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Acronyms

ADB	Asian Development Bank
APSCL	Ashugonj Power Station Company Limited
ARR	Aggregate Revenue Requirement
BDT	Bangladesh Taka
BEA	Bhutan Electricity Authority
BEE	Bureau of Energy Efficiency
BERC	Bangladesh Energy Regulatory Commission
BIFPCL	Bangladesh-India Friendship Power Company Limited
BPC	Bhutan Power Corporation
BPL	Below Poverty Line
BPDB	Bangladesh Power Development Board
CERC	Central Electricity Regulatory Commission
CEA	Central Electricity Authority
CEB	Ceylon Electricity Board
CPI	Consumer Price Index
CPP	Captive Power Policy
CPPA	Central Power Purchasing Agency
CPGCBL	Coal Power Generation Company Bangladesh Limited
DESCO	Dhaka Electric Supply Company Limited
DGPC	Druk Green Power Corporation
DPDC	Dhaka Power Distribution Company Limited
DSM	Demand Side Management
ECR	Energy Charge Rate
EGCB	Electricity Generation Company of Bangladesh
EMRD	Energy & Mineral Resources Division
GERC	Gujarat Electricity Regulatory Commission
GoB	Government of Bangladesh
GoI	Government of India
GoP	Government of Pakistan
GoSL	Government of Sri Lanka
GWh	Giga Watt Hour
HP	Horse Power
IEA	International Energy Agency
IPPs	Independent Power Producers
KESC	Karachi Electric Supply Corporation
KV	Kilo Volt
kWh	Kilo Watt Hour
LKR	Sri Lankan Rupee

LV	Low Voltage
MoA	Ministry of Agriculture
MoEA	Ministry of Economic Affairs
MoPE	Ministry of Power and Energy
MoPEMR	Ministry of Power, Energy and Mineral Resources
MoP	Ministry of Power
MW	Mega Watt
MYT	Multi Year Tariff
NEEPCO	North Eastern Electric Power Corporation
NEP	National Energy Policy
NEPRA	National Electric Power Regulatory Authority
NTGMP	National Transmission Grid Master Plan for Bhutan
NHPC	National Hydroelectric Power Corporation
NTDC	National Transmission and Despatch Company
NTPC	National Thermal Power Corporation
NWPGCL	North West Power Generation Company Limited
Nu.	Ngultrun, Currency of Bhutan
O & M	Operation and Maintenance
PFC	Power Finance Corporation
PEPCO	Pakistan Electric Power Company
PGCB	Power Grid Company Limited of Bangladesh
PPA	Power Purchase Agreement
PPIB	Private Power and Infrastructure Board
PUCSL	Public Utilities Commission of Sri Lanka
REB	Rural Electrification Board
REC	Rural Electrification Corporation
REMP	Rural Electrification Master Plan
ROR	Rate of Return
RPCL	Rural Power Company Limited
SAARC	South Asian Association for Regional Cooperation
SERC	State Electricity Regulatory Commission
SEC	SAARC Energy Centre
SPP	Small Power Policy
SPP	Small Power Producer
SPPA	Small Power Purchase Agreement
SREDA	Sustainable and Renewable Energy Development Authority
TDR	Tariff Determination Methodology
TOU	Time of Use
TPM	Transfer Price Mechanism
TSU	Transmission System Users

TTC	Total Transmission Cost
VAT	Value Added Tax
WAPDA	Water and Power Development Authority
WZPDCL	West Zone Power Distribution Company Limited

Executive Summary

Electricity is an essential requirement for all aspects of our life. It has been recognized as a fundamental human need. Electricity encompasses all sectors of the economy which require available and affordable electricity for smooth functioning. Electricity supply imposes certain cost on the supplier that must be recovered from the beneficiaries to sustain the supply in future. Electricity pricing practices play significant roles in economic development, technology development and energy consumption behavior. Electricity tariffs need to signal to both consumers and suppliers. At the same time, tariffs need to reflect the country's energy policy priorities.

The decision on electricity tariff design of a country is complex issue. It requires the government/independent regulatory body to make balance among various interests. However, there are certain principles/objectives that need to be followed while determining electricity tariff. The objectives are: (i) Principle of economic efficiency; (ii) Principles relating to fairness and equity; (iii) Financial viability of the sector; (iv) Simple tariff structure; and (v) Other economic and political requirements. These objectives often conflict with one another; therefore it is necessary to accept certain trade-offs on designing electricity tariff.

This study focuses on the prevailing electricity pricing practices in the selected SAARC Member States, with regard to price determination methodologies, related institutional arrangements and regulatory setups. The theoretical aspects of electricity pricing and objectives of pricing are also described. The study covers mainly generation, transmission, distribution and retail supply tariff determination methodologies that are being adopted by the Member States. Under this study, the Member States namely Bangladesh, Bhutan, India, Pakistan and Sri Lanka are considered.

Tariff setting objectives of selected SAARC Member States are mix of objectives including cost reflectivity and social concern, but aiming to reach efficient tariff. Most of the selected Member States have Tariff Methodology, formulated by respective regulator, wherein set of working methods in determining the generation, transmission, distribution and retail supply tariff has been described.

Cost of electricity supply to the end customers comprises of mainly generation cost, transmission cost and distribution margin. The total cost of supply is segregated into various cost components. In case of a generation company, the

major cost components of tariff are fuel cost, transportation cost of fuel, employee cost, repair & maintenance cost, depreciation cost, pollution control expenses, taxes and return on capital. The structure of the electricity generation sources of selected Member States comprises of mostly public generation, IPP purchases and rental power plants. The tariff for generation companies is determined on cost plus basis and in most cases under power purchase agreements. The generation tariff determination is linked with achievement of some operational norms in case of all selected Member States. In generation sector, a Single-Buyer model has been adopted by Bangladesh, Bhutan, Pakistan and Sri Lanka where the Single-Buyer purchases electricity from all public and private generation companies and sells it to the distribution companies.

In case of India, state generation utilities sell electricity to distribution companies based on long-term contracts at the prices decided by SERCs or PPAs. The CERC regulates tariffs of generating companies owned or controlled by the central government as well as IPPs that supply more than one state. In addition to this long-term contract, there are two other pricing mechanisms prevailing in India which are short-term contract, used by traders for inter-state purchases through open access, and spot market. The SERCs determines the wholesale, bulk and retail tariff for electricity and the tariff for intra-state transmission facilities within its respective state.

The distribution companies procure electricity from the Single Buyer (that purchases electricity from all generation companies) and sell to the end users. The tariff for generation companies is determined on annual cost plus basis. For the case of India, Sri Lanka and two companies of Pakistan, the distribution tariff is calculated based on multi-year tariff principles. The major components of tariff determination for a distribution company are power purchase cost, employee cost, operation & maintenance cost, depreciation cost, energy losses, taxes and return on capital.

In an attempt to deal with the social consequences, Member States have implemented lifeline-tariff policy. Member States have cross-subsidies among customer categories: lower for households, mainly rural, and agriculture, and higher for other customer categories. One of the common features of the SAARC Member States is incremental block tariff structure for domestic customers, where a unit price increases in the amount of electricity use. Recognizing the importance of demand side management, Member States have implemented some sophisticated tariff structures such as Time of Use tariff, seasonal tariff and capacity charge, reactive energy and power factor adjustment charge.

The current end-user tariff policy in Member States is to have uniform tariffs (i.e. same tariff is maintained for a given customer category) across the country/state (in case of India). However, the retail supply tariff differentiates between rural and urban customers in Bangladesh, Bhutan and India for selected customer category(s). In the Member States, electricity supply tariffs are also differentiated by voltage level as different customer off-take voltages.

Electricity pricing varies from country to country. There are many reasons that account for electricity price differences. The level of electricity price depends on industry structure, ownership structure, fuel mix in power generation and government's policy objectives like economic efficiency and other social policy obligation.

In actual fact, the decision on tariff design of a country is a multifaceted matter. The government and regulatory authority have to make balance among various interest groups. For instance, the electricity consumers seek a low price. The suppliers need high profit. The country itself needs a tariff with high economic yield and the environment needs an environmentally sustainable energy system. Higher tariff may result into loss of consumer welfare. On the other hand, un-reasonably lower tariff may leave the supplier with deficit revenue and lead to poor quality of service. The challenge towards a rational tariff is to attain justifiable tariff to all stakeholders.

Designing a justifiable tariff and its implementation can serve multiple objectives simultaneously. In order to follow the price setting principles/objectives mentioned in the earlier section, there are various pricing approaches/methods available for the consideration such as marginal cost pricing, cost-plus pricing, peak-load pricing, two-part tariff, price cap and performance based approach. Each of these has its own advantages and disadvantages. Selection of appropriate pricing approach for a particular country depends upon a number of parameters such as availability of adequate and reliable information, responsiveness of market, degree of competitiveness and other socio-economic factors.

Chapter 1
Introduction

1.1 Background

The Energy Ministers, during their Third Meeting (Colombo, 29 January 2009), considered and approved a Concept Paper on SAARC Energy Ring, with the observation that it is a dynamic concept and will evolve over time with the experience of the Member States and changing ground realities. The Meeting further decided formation of Expert Groups for different commodities and services. As a follow-up, the Working Group on Energy constituted Expert Groups on (i) Oil and Gas; (ii) Electricity; (iii) Renewable Energy; and (iv) Technology/ knowledge sharing (including energy efficiency, coal, etc.).

The first Meeting of the Experts Group on Oil & Gas was held in Dhaka on 25-26 July 2011 and recommended some activities to be undertaken by SAARC Energy Centre. Recognizing the importance of energy pricing, one of the proposed activities was study on sharing experiences in the areas of pricing mechanisms for oil and gas, operational and technical aspects of LNG terminals, and LPG for household and industrial use. A study on "Pricing Mechanisms for Oil and Gas in SAARC Member States" has already been conducted by SEC, as an in-house effort, in 2012. With a view of study on pricing mechanisms for all energy carriers of an energy system of a country, SEC proposed this study, under its thematic area of "Programme on Energy Trade (PENT)", in 2013 programme activity which was approved by the Governing board and higher SAARC bodies.

1.2 Objective

The main objective of this study on "Pricing Mechanisms for Electricity in SAARC Member States" is to share the experiences in the area of electricity pricing among the Member States and promotion of energy trade in the region. The institutional, legal and regulatory frameworks for electricity sector of the Member States are also examined under this study.

1.3 Methodology

The study has been conducted as an in-house effort of SAARC Energy Centre, based on literature review of the respective Member States. A detailed country-wise review of available reports and literatures related to electricity pricing

policies, practices and methodologies adopted by the SAARC countries was carried out by making contact with relevant web sites, authors and peers. It was a desk-top type study, so SEC professionals visited to the concerned government authorities in Pakistan, but for other countries the approach was to visit relevant websites, phone calls and email correspondences with similar types of agencies. The necessary information and data was also collected directly from concerned officials' of different government institutions of SAARC countries. Some observations stated in the report are made by extracting relevant information from the reports of government agencies and the available studies conducted earlier by different experts/institutions.

1.4 Limitations

The study, desk-top type, was designed to cover all SAARC Member States, but due to the limitations in availability of data and relevant pricing information, it covers Bangladesh, Bhutan, India, Pakistan and Sri Lanka. Besides, the level of detail varies amongst the SAARC countries due to non-availability of data and pricing information. The study covers electricity pricing policies, pricing objectives and methodologies implemented by the SAARC countries for electricity tariff determination. This study includes the tariff determination methodologies for generation, transmission, distribution and retail supply. It also includes theoretical aspects of electricity pricing along with the institution and regulatory setup of the Member States.

Chapter 3
Theoretical Overview of Electricity Pricing

3.1 Objectives of Electricity Pricing

Electricity Tariff design is aimed at profit maximization from the point of view of an utility while the government's interest is welfare maximization and making available affordable service to the poor. To maximize profits, the utility seeks prices that equate marginal revenue and marginal cost. The decision of tariff requires making balance among various interests conflicting in nature. Higher tariff may result into loss of consumer welfare. On the other hand, un-reasonably lower tariff may leave the utility with deficit revenue and lead to poor quality of service. However, there are certain principles/objectives that need to be followed while determining electricity tariff. The approach to electricity pricing recognizes the existence of the following objectives:

- The national economic resources must be allocated efficiently not only among different sectors of the economy, but also within the components of the electric power sector itself;
- Principles relating to fairness and equity must be satisfied, including; (i) allocating costs according to the respective burdens; (ii) assuring price stability and avoiding large price fluctuation; (iii) providing minimum level of service to consumers who may not be able to afford the full cost;
- The power price should raise sufficient revenues to meet the financial requirements of the sector;
- The electric power tariff structure must be simple enough to facilitate the metering and billing of consumers;
- Other economic and political requirements must also be considered (e.g. subsidy to certain sectors or geographic areas).

3.2 Theoretical Aspects

Since the above objectives often conflict with one another, it is necessary to accept certain trade-offs between them on designing electricity tariff. In order to follow these principles/objectives of tariff, there are various approaches/methods available for the consideration. Each of these has its advantages and disadvantages. Selection of appropriate approach depends upon the socio-economic characteristics

and degree of competition existed in the sector. Some of the methods/approaches are discussed in the subsequent sections.

Marginal Cost Pricing

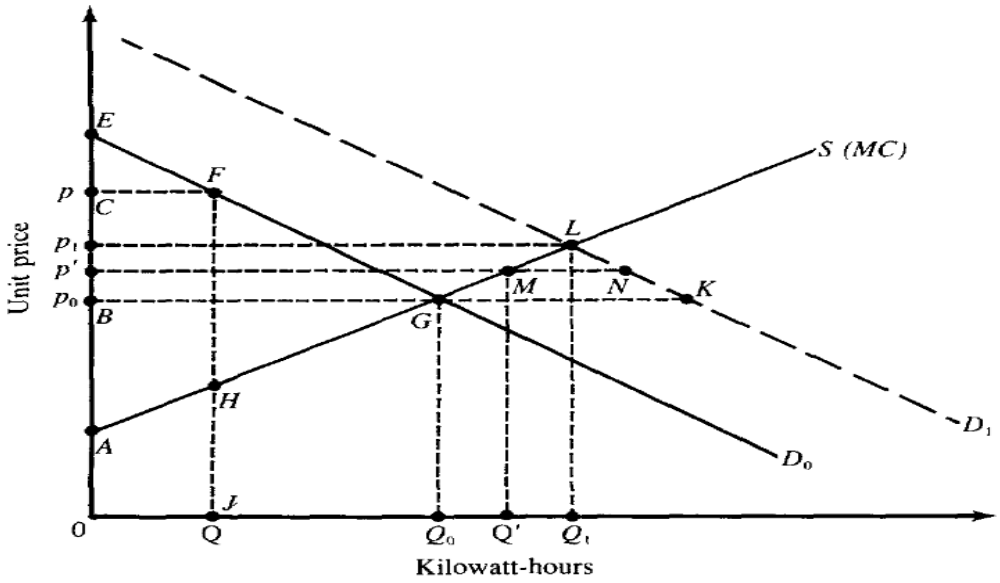
In case of competitive market, marginal revenue equals marginal cost. This marginal cost pricing maximizes welfare, with the interests of the utility coinciding with the interests of the government. Economists have considered marginal cost pricing principles as the most efficient pricing theory so far as theoretical economic analysis is concerned. Regarding marginal cost pricing principle for public utilities, Hotelling's (1939) contribution to the subject is considered to be one of the pioneering works. According to Mohan Munasinghe and Jeremy J. Warford (1982), for efficient resource allocation the prices must equal to the marginal cost of supply.

Munasinghe presents a pricing framework based on long run marginal cost. The rationale for setting price equal to marginal cost may be clarified with the simple demand-supply diagram shown in figure 1. Let $EFGD_o$ be the demand curve, which determines the kilowatt-hours of electricity demanded in a given year at any given average price level. *AGS* is the supply curve, and is represented by the marginal cost *(MC)* of supplying additional units of output. At price *p* and demand *Q*, the total benefit of consumption is represented by the consumers' willingness to pay i.e. the area under the demand curve *OEFJ.* The cost of supplying the output is the area under supply curve *OAHJ.* As a result, the net benefit (total benefit minus supply cost) is given by the area *AEFH.* The maximum net benefit *AEG* is achieved when price is set equal to marginal cost at the optimal market clearing point *G* i.e. (p_o, $\boldsymbol{Q_o}$**).** In mathematical terms, the net benefit *(NB)* is given by

$$\text{NB}=\int_O^Q p(q)dq - \int_O^Q MC\ (q)dq$$

where *p(Q)* and *MC(Q)* are the equations of the demand and supply curves, respectively. Maximizing *NB* yields *d(NB)/dQ = p(Q) - MC(Q)=0,* the point at which the demand and marginal cost curves intersect (p_o, Q_o).

Figure 1: Supply and Demand for Electricity Consumption



The analysis so far has been static. If we consider the dynamic effect of demand growth from year zero to the first, which leads to an outward shift in the demand curve from D_0 to D_1. Assuming that the correct market clearing price p_0 was prevailing in year zero, excess demand equal to GK will occur in the first year. Ideally, the supply should be increased to Q_1 and the new optimal market clearing price established at p_1. The available information concerning the demand curve D_1 may be incomplete, however, making it difficult to locate point L.

The technical-economic relations underlying the production function usually enable the analyst to determine the marginal cost curve more accurately. Therefore, as a first step, the supply may be increased to an intermediate level Q' at price p'. The existence of the excess demand MN indicates that both the supply and the marginal cost price should be further increased. On the other hand, if L is overshot and there is excess supply, then it may be necessary to wait until demand growth catches up with the overcapacity. In this iterative manner, it is possible to move along the marginal cost curve toward the optimal market clearing point. As the optimum is approached, it is also shifting with demand growth. Therefore, this moving target may never be reached. The basic rule of setting price equal to the marginal cost and expanding supply until the market clears, however, is still valid.

Mohan Munasinghe comes to the conclusion that tariff based on the long run marginal cost is a compromise between many different objectives. Therefore, no ideal tariff exists. By using the long run marginal cost approach, it is possible to revise and improve the tariff on a consistent and continual basis. Gradually optimal

price is reached over years without subjecting long-standing consumers to unfair shocks because of large abrupt price changes. Most economists agree that price should be set equal to marginal cost. But here the dilemma is whether the marginal cost should be short run marginal cost or long run marginal cost.

Cost-Plus Pricing

In actuality, companies may not be able (and it may be too expensive) to collect precise data on marginal revenue and marginal cost to determine the optimal level of output and price at the point at which marginal cost is equal to marginal revenue. Therefore, companies have developed rules of thumb or short-cut methods for pricing their products. The most widely used of such pricing rules is cost-plus pricing (also called "markup pricing" and "full-cost pricing"). The usual method is for the company to first estimate the *average variable cost* of producing or purchasing and marketing the product for a normal or standard level of output. The company then adds to the average variable cost an *average overhead charge*, so as to get the estimated *fully allocated average cost*. To this fully allocated average cost, the company then adds a *mark up* on cost for profits.

Cost-plus pricing is also termed as Rate of Return (ROR) method. It allows companies to earn a reasonable rate of return on their investment after meeting all other expenses. On the basis of information available for the last two/three years, cost is approved. Under this method, the utilities are also entitled to make a claim for the unforeseen expenses such as fuel surcharge adjustment etc. for the past years. The following is the simple formula used for approving tariff using cost-plus method:

$$PR = PPC + E + D + T + (B \times r)$$

Where
RR= Revenue Requirement of the Utility;
PPC= Cost of Power Purchase;
E= Operating expenses (cost of items such as labour, fuel, repair and maintenance etc.);
D= Annual Depreciation expenses;
T= Taxes payable to the Government;
B= Rate Base (the amount of capital invested in the business);
r= Allowed or reasonable rate of return.

The use of cost-plus pricing has several important advantages such as it requires less information and less precise data, it seems easy and simple to use, it results

relatively stable price when costs do not vary very much over time and it can provide a clear justification for price increases when cost rise. Regardless of these important advantages and widespread use, cost-plus pricing is criticized on several important grounds. The criticisms are: it is based on accounting and historical costs rather than on replacement and opportunity costs; it is based on the average cost rather than on the marginal cost of production; and it ignores conditions of demand.

Peak-load Pricing

Peak-load pricing refers to the charging of a higher price for a good or service during peak times than at off-peak times. The demand for electricity is higher during some periods (e.g. in the evening and in the summer) than at other times (e.g. during the day or spring). Electricity is also a non-storable service (i.e., it must be generated when it is needed). In order to satisfy peak demand, utilities must bring into operation older and less efficient equipment and thus incur higher marginal costs and charge higher prices. The peak-load pricing, however, requires sophisticated measurement of customer usage, with advanced metering technologies for energy.

Two-part Tariff

Two-part tariff refers to the pricing practice in which consumers pay an initial fee for the right to purchase a product or service, as well as a usage fee or price for each unit of the product they purchase. In case the utility possesses some market power, its profit maximization prices would exceed the marginal cost, resulting in welfare loss unlike the perfectly competitive environment. Here, the utility charges separate prices for different elements of the service unlike in linear tariff, wherein a single price is charged for the service. In the electricity sector, under two-part tariff, customer pays a monthly fee for access and a usage fee for the consumption of electricity. In South Asian countries, utilities use such type of tariff for pricing especially for domestic users. In the case of electricity sector, the term two–part tariff is also used sometimes to mean a tariff that includes one capacity (i.e. kilo-Watt) component and other energy (i.e. kWh) component.

Price Cap and Performance Based Regulation

Under Price Cap regulation, on the basis of historical cost and future efficiency gains, a ceiling price is fixed by the regulator. Regulator approve tariff taking into account the general price level and future efficiency gains. And under Performance Based Regulation approach, tariff is linked with the performance of the utility. For

instance, if a utility is able to reduce more transmission and distribution losses it may be allowed to earn more return on the capital base. Conversely, poor performance may result into penalty.

Chapter 3
Electricity Pricing

3.1 Electricity Pricing in Bangladesh

Bangladesh has shown remarkable growth in recent years. Economic growth, urbanization and increased industrialization have amplified the country's demand for electricity. At present, demand growth is about 10% which is expected to be more in coming years and, 62% of the total population[1] has access to electricity. The vision of the Government is to provide access to affordable and reliable electricity to all by 2021.

The Electricity Act 1910 governs the power sector of Bangladesh. In 1996, Bangladesh initiated its national energy policy which included the familiar recommendations for sector unbundling, encouragement for private sector participation, supply of energy at reasonable & affordable price and establishment of an energy regulator. The National Energy Policy of Bangladesh focuses that the tariff setting policy has to be consistent with the financial requirement of the power sector institutions, address the social commitments like subsidy with the aim of promoting rural development and lifeline tariff and the provision for automatic price adjustment.

In 2003, the Government of Bangladesh enacted the Bangladesh Energy Regulatory Commission Act. One of the objectives of this Act is to determine tariffs in a transparent way. The two most important duties of Bangladesh Energy Regulatory Commission (BERC) are licensing and tariff setting for generation, transmission and distribution of electricity. Bangladesh Energy Regulatory Commission (Electricity Generation Tariff) Regulations[2], 2008 provides the methodology for the determination of electricity generation tariff. Bangladesh Power Development Board performs a Single Buyer function which buys the electricity from all generating companies connected to the transmission network and sells it to the distribution companies.

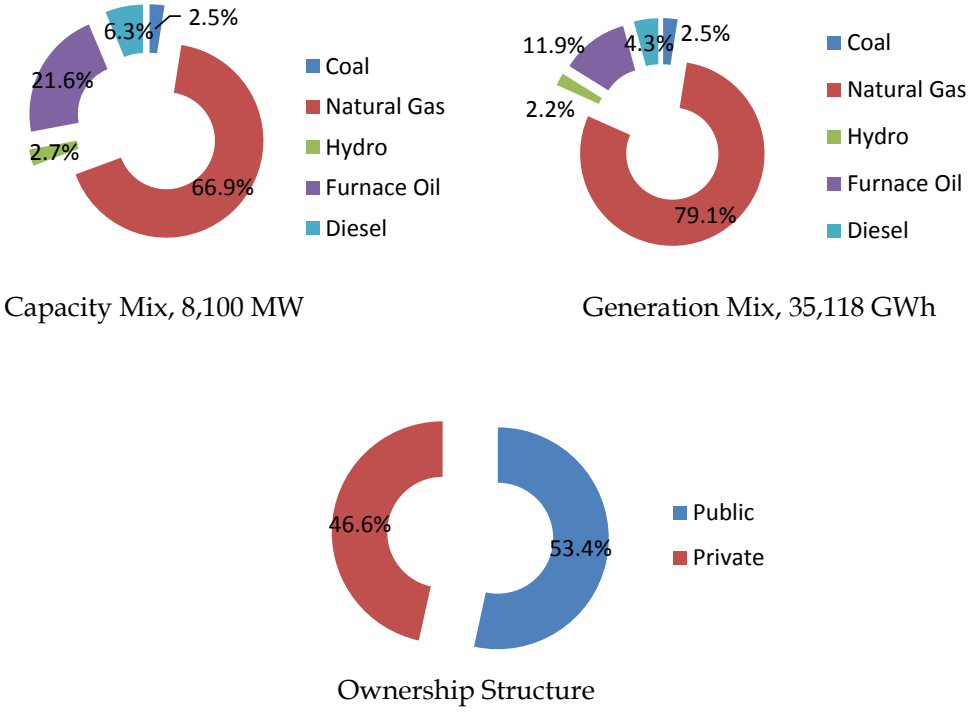
3.1.1 Power Sector Overview

The total installed capacity in Bangladesh is 8,100 MW as of June 2012 (BPDB, 2012). Natural gas represents around 67% of total installed capacity. Furnace Oil is the second largest source, accounting for about 22% of total installed capacity. According to the Bangladesh Power Development Board, the total electricity

[1] *Including renewable energy.*
[2] *Bangla version.*

generation in the country is 35,118 GWh in FY 2012. The share of natural gas in total electricity generation is around 79%, followed by the Furnace oil with a share of around 12%.

Figure 2: Power Generation of Bangladesh



Source: BPDB, 2012.

Beside the public sector generation, the total generation capacity includes the private sectors (IPP, SIPP/rental, REB for PBS). The contribution of the private sector to the total capacity is about 47%. At present electricity demand growth in Bangladesh is about 10% which is expected to be more in coming years. Bangladesh is heavily dependent on natural gas for its power generation. The country's gas production is already insufficient and the gas reserves are depleting due to over increasing demand. The government of Bangladesh is well conscious of this insecure fuel monopoly and the power sector is currently looking into the development of coal fired power stations. Government is also considering imported Liquefied Natural Gas to supplement present natural gas shortage.

3.1.2 Electricity Tariff Methodology

The fundamental policy of the Government of Bangladesh for setting the electricity tariff stipulates the achievement of the cost reflective tariff and generates a surplus

to expand coverage and supply, and improve the quality of service. Bangladesh Energy Regulatory Commission (*Electricity Generation Tariff*) Regulation 2008 has been adopted by Bangladesh Energy Regulatory Commission (BERC) in exercise of the power conferred by section 59 of the BERC Act, 2003 (Act No 13 of 2003). This regulation is applicable to licensed applicants for electricity generation which provides the methodologies for determination of generation tariff.

BERC has also developed electricity transmission and distribution tariff methodologies[3] for establishing a standard which would be use by a licensee in calculating rates as part of a transmission and distribution tariff respectively. These two methodologies are applicable for fixation of tariffs (or any modification in existing tariffs) for electricity transmission and distribution services. The tariffs are determined on the basis of overall revenue requirement to maintain operations and attract capital for investment, but maintain least cost to the consumers.

(a) Determination of Generation Tariff

At present, Bangladesh Power Development Board (BPDB) performs a Single Buyer function. BPDB purchases the electricity from all public & private generation companies connected to the transmission network and sells it to the distribution companies at the 132 kV and 33kV level. However, the Small Power Policy[4] and the Captive Power Policy[5] imply that SPPs and CPPs are able to sell electricity directly to end-use consumers and/or distribution companies.

According to the Electricity Generation Tariff Methodology, generation tariff comprises of two parts, namely, Fuel Cost Recovery Rate which is based on the actual fuel expense for electricity generation and Plants Revenue Requirements. The main objective of the Fuel Cost Recovery Rate, a component of the two part generation tariff, is to charge electricity generation cost to the consumers on a standard basis considering the changes of fuel cost in the market. In Bangladesh, Fuel Cost Recovery Rate is linked with the achievement of the operational norms namely, station heat rate. The Fuel Cost Rate is calculated on the basis of set standard Heat Rate (± 10%) with the following formula:

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[3] *Electricity Transmission Tariff Methodology and Electricity Distribution Tariff Methodology of BERC are in Draft Stage.*

[4] *The Government of Bangladesh has decided to allow private sector investors to establish Small Power Plants (SPP) on a fast track basis, for generation of electricity for own use and sell the surplus to other users. The plant size could be in the order of 10 MW.*

[5] *Government of Bangladesh declares Guidelines to harness the surplus capacity of captive power plants, and permit electric utilities to purchase electricity from captive power plants.*

$$\textit{Fuel Cost Rate} = \frac{(\textit{Fuel Purchase Price} + \textit{Distribution Expences to the Plant}) \times (\textit{Heat Rate})}{\textit{Net Electricity Generation}}.$$

The Plant Revenue Requirement is the amount of income that the generation licensee should have the opportunity to earn in order to maintain operations and attract capital for investment. Basically this is the cost of providing service to the customers. The total annual revenue requirement of a generation licensee is the sum of a return on rate base plus the sum of the total annual operating costs.

Total Annual Revenue Requirement= Return on Rate Base + Total Costs.

The overall Rate Base consists of the depreciated value of the used and useful assets plus the regulatory working capital.

Rate Base= Used and Useful Assets + Regulatory Working Capital.

Return on Rate Base= Rate Base × Rate of Return.

The rate of return on rate base is calculated as the weighted average cost of capital.

The Total Costs components of the Revenue Requirement are the sum of costs associated with the operation and maintenance (O&M) of the licensee's system, the straight- line depreciation costs of used and useful assets used for the tariff rate year, taxes, and any other necessary costs related to the operation of the licensee's system.

Total Costs= O & M Costs + Depreciation + Income & other Taxes.

The recommended annual revenue requirements would be the sum of the proposed return on rate base plus the total operating expenses which include the depreciation and taxes of the Test Year[6]. The total current operating revenues would be the sum of generation service revenues, income from other services rendered, interest income (if any) and any miscellaneous income. The amount of the said recommended operating revenue requirements needs to be compared to the current operating revenues to determine the amount of increase that will need to be obtained to allow generation licensee to receive the revenue requirement. Therefore, the proposed revenue increase is calculated with the following formula:

Proposed Revenue Increase= Recommended Operating Revenues – Current Revenues.

[6] *This is a standard 12-month- period, which provides a uniform data base for the calculation of tariff.*

The above proposed revenue increase is subject to income tax which is multiplied by a revenue conversion factor[7] to get the Recommended Revenue Increase. Hence, the total recommended revenue requirement is the sum of the current revenues plus the recommended revenue increase which is shown in the formula set out below:

Recommended Total Revenue Requirement=Total Current Revenue + Recommended Revenue Increase.

Hence, Electricity Generation Service Tariff Rate is calculated by dividing the above recommended total revenue requirement with net electricity generation and finally the overall Generation Tariff (the total generation tariff which is charged/billed to the consumers) is calculated with the following formula:

Overall Generation Tariff[8]*=*
(Fuel Cost Recovery Rate × Delivered Electricity to the Transmission)
+
(Service Tariff Rate × Delivered Electricity to the Transmission).

The Bulk Supply Tariff charged by the Single Buyer-BPDB to the distribution companies are shown in the below Table.

Table 1: Bulk Supply Electricity Tariff[9] *in Bangladesh*

	Charge, BDT/kWh
At 132 kV	5.3250
At 33 kV	4.0325 – 5.4050

Source: BERC.

As seen in the above table, the bulk supply tariff differentiates between the voltage levels of delivery as well as the categories of customer. For instance, at 33 kV voltage level, bulk tariff is the lowest for rural area, with the consideration of socio-economic condition of the rural community, and it is the highest for urban area and is set at BDT 4.9775/kWh for other areas.

[7] *Revenue Conversion Factor=1/(1-Income Tax Rate).*
[8] *The fuel cost and the generation service cost have to be mentioned separately in the bill.*
[9] *With effect from 1 September 2012.*

(b) Determination of Transmission Tariff

The Power Grid Company Limited of Bangladesh (PGCB) looks after the electricity transmission of the country. The main function of PGCB is wheeling of electricity from BPDB power stations and generation companies to distribution entities utilizing the transmission network. PGCB gets its electricity wheeling charge from distribution entities at the rate fixed by Bangladesh Electricity Regulatory Commission (BERC). However, BERC has developed a Draft Electricity Transmission Tariff Methodology for establishing a standard which would be use by a licensee in calculating rates as part of a transmission tariff. This Methodology is applicable for fixation of tariff (or any modification in existing tariff) for electricity transmission service. The transmission tariff would be determined on the basis of overall revenue requirement to maintain operations and attract capital for investment, but maintain least cost for consumers.

(c) Determination of Distribution Tariff

The distribution companies procure electricity from the Single Buyer- BPDB, under a Bulk Supply Tariff, and sell to the end users. The distribution companies/licensee may also purchase wholesale electricity from small power and captive power producers directly. BERC has developed a Draft Electricity Distribution Tariff Methodology for establishing a standard which will be utilized by a licensee in calculating rates as part of a distribution tariff. This methodology is applicable for fixation of tariff (or modification of any such existing tariff) for electricity distribution services.

According to this distribution tariff methodology, the distribution tariff mainly comprises of two components such as Energy Rate and Demand Rate. The electric energy rate is the weighted average of all wholesale energy purchases for the billing period on a kilowatt hour basis and the distribution licensee does not earn a return or profit on the energy portion of a consumer's bill. In case of the single wholesale supplier, the energy component is computed as follows:

$$\text{Energy Rate} = \frac{(Wholesale\ Electricity\ Cost + Transmission\ Cost + Transmission\ Loss)}{kWh\ Received}$$

Where:
Transmission Loss= (%Loss × Amount kWh Wholesale Electricity Sent × Wholesale Electricity Purchase Cost)/kWh Sent.

The Demand Rate component provides the opportunity for the licensee to earn sufficient revenues to cover all of its operating expenses, provides for continuing

improvement of its operating system, and attract capital investment. The demand rate schedules for the individual consumer classes are designed to be equitable and reasonable to the consumers served.

Table 2: Retail Supply Electricity Tariff[10] in Bangladesh

Customer Types	***Energy Charge (BDT/kWh)***	***Service Charge (BDT/Month)***	***Demand Charge (BDT/kW/Month)***	***Minimum Charge (BDT)***
Domestic-urban	3.33–9.38	10 & 30	15	100
Domestic-rural	3.61–9.38	10 & 30	15	100
Agriculture	2.51(3.67)[a]	30	0 & 40	125/HP
Industrial- Category C (small industry, 0.40 kV)				
Flat	6.95	70	0 & 40	-
Off-peak	5.96			
Peak	8.47			
Industrial- Category F (medium voltage general use, 11kV)				
Flat	6.81	400	45	80/kw or 8000
Off-peak	5.96			
Peak	9.33			
Industrial- Category H (high voltage general use, 33kV)				
Flat	6.48	450	40	80/kw or 8000
Off-peak	5.87			
Peak	9.14			
Industrial- Category G-2 (extra high voltage general use, 132kV)				
Flat	6.16	500	40	80/kw or 8000
Off-peak	5.57			
Peak	8.67			
Commercial and Office Use-Category E				
Flat	9.0	10 & 30	25	125/kw
Off-peak	7.22			
Peak	11.85			
Non Residential Light & Electricity-Category D				
Flat	4.53(4.49)[a]	10 & 30	20	125/kw
Road Light & Water Pump-Category J				
Flat	6.48	210	40	-

[a]*For Rural Customers.*

Source: BERC.

The current policy in Bangladesh is to have uniform retail tariffs, but with slightly higher tariffs in rural areas to reflect the higher costs of supply. The total retail

[10] *With effect from 1 September 2012.*

supply tariff for all consumer categories comprises of energy charge, service charge, demand charge, minimum charge and a VAT. As seen in the above table, the retail supply tariff differentiates between the rural and urban consumers in domestic, agriculture-irrigation and non-residential light. In case of domestic customers, energy charges vary according to the monthly consumption stages (total six stages) starting from 0-75 kWh to >600 kWh. Service charge varies according to the type of connection either single or three phase. The classifications of industrial customers are based on delivered voltage level (0.40 kV, 11kV, 33kV and 132 kV) of electricity. Time of Use tariffs is applicable industrial and commercial customers. The detail of the Retail Electricity Tariffs of Bangladesh for different Customer Types along with their classifications is attached in Appendix A.

Bangladesh has a special tariff structure for 'Q' class-power consumers who buy electricity at higher price. This special tariff is applicable for labor-intensive and export-oriented industries for getting uninterrupted, reliable and quality supply of electricity. BPDB supplies electricity for these special customers at three voltage levels at the following charges:

Table 3: Retail Supply Electricity Tariff[11] for 'Q' Class Consumers in Bangladesh

Voltage Levels	***Energy Charge (BDT/kWh)***	***Service Charge (BDT/Month)***	***Demand Charge (BDT/kW/Month)***	***Minimum Charge (BDT/kW/Month)***
At 132 kV	13.88	500	40	80
At 33 kV	14.45	450	40	80
At 11 kV	14.99	400	40	80

Source: BERC.

3.1.3 Analyses and Key Findings

At present, demand growth is about 10% which is expected to be more in coming years and, 62% of the total population has access to electricity. The vision of the Government is to provide access to affordable and reliable electricity to all by 2021.

The policy of Government of Bangladesh for setting the electricity tariff stipulates the achievement of the cost reflective tariff and generates a surplus to expand coverage and supply, but maintain least cost to the consumers. The tariff setting policy addresses the social commitments of the Government as well.

[11] *With effect from 1 June 2012.*

Presently, Bangladesh Power Development Board (BPDB) performs a Single Buyer function which purchases the electricity from all public & private generation companies connected to the transmission network and sells it to the distribution companies. The distribution companies procure electricity from the Single Buyer, under a Bulk Supply Tariff, and sell to the end users. However, the Small Power Policy and the Captive Power Policy imply that SPPs and CPPs are able to sell electricity directly to end-use consumers and/or distribution companies. Power Grid Company Limited, responsible for electricity transmission, gets its electricity wheeling charge from distribution entities at the rate fixed by Bangladesh Electricity Regulatory Commission (BERC).

The two most important duties of BERC, a regulator started functioning from 2004, are licensing and tariff setting for generation, transmission and distribution of electricity. Bangladesh Energy Regulatory Commission (*Electricity Generation Tariff*) Regulations 2008 has been adopted by BERC which provides the methodologies for determination of electricity generation tariff. BERC has also developed draft electricity transmission and distribution tariff methodologies.

In accordance with the Electricity Generation Tariff Methodology, generation tariff comprises of two parts, namely, Fuel Cost Recovery Rate which is based on the actual fuel expense for electricity generation and Plants Revenue Requirement which is amount of income that a generation licensee should have the opportunity to earn for operations and attract capital for investment. Fuel Cost Recovery Rate is linked with the achievement of some operational norms.

The structure of the electricity generation sources of BPDB, single buyer of electricity in the country, comprises of its own generation, public generation entities, IPP purchases and rental power producers. The costs of electricity generation from own generation, publicly owned generation, IPPs and rental power producers are BDT 3.67/kWh, BDT 2.02/kWh, BDT 3.66/kWh and BDT 10.18/kWh respectively (BPDB, Annual Report 2011-2012)[12]. The average polled generation cost of BPDB for all the sources stands at BDT 5.36/kWh for the year 2012. On the other hand, the regulated bulk supply tariff charged by the BPDB to distribution companies in the range of BDT 4.0325 to 5.325/kWh which leave BPDB with a negative margin; therefore the achievement of the cost reflectivity tariff setting policy in Bangladesh has not been duly met. The recent increase of share of

[12] *In addition to these, Bangladesh has recently started import of 500 MW electricity from India with a cost of BDT 4.00/kWh (25 years contract with Government of India) and BDT 6.34/kWh (3 years contract with Power Trading Corporation, India).*

rental power producers[13] in the total generation mix is contributing a lot to the negative margin of BPDB. The regulated bulk supply tariff differentiates between the voltage levels of delivery as well as the categories of customer; it is the lowest for rural area distribution taking into account the socio-economic conditions of the rural community.

According to draft distribution tariff methodology, the distribution tariff mainly comprises of two components such as Energy Rate and Demand Rate. The energy rate is the weighted average of all wholesale energy purchases from which distribution licensee does not earn a return on the energy portion of a consumers' bill. However, the demand rate component provides the opportunity to earn in order to maintain operations and attract capital investment.

The current policy in Bangladesh is to have uniform retail tariffs across the country, but with slightly higher tariffs in rural areas to reflect the higher costs of supply. The retail supply tariff differentiates between the rural and urban consumers in domestic, agriculture-irrigation and non-residential light customer classes. Time of Use tariffs is applicable for industrial and commercial customers. Among the industrial customers, differentiated rates are maintained at different voltage levels of delivery. Residential customers enjoy a life-line tariff. Bangladesh has a special tariff structure at higher rates for labor-intensive and export-oriented industries for getting uninterrupted, reliable and quality supply of electricity.

The tariff structure for the end customers is distorted with cross-subsidies from commercial consumers to residential consumers. With the uniform tariffs across the country, some distribution companies achieve higher profits while others enable to make profit and struggle to achieve their commercial targets. The distribution costs and the average revenues differ significantly between rural and urban areas due to the different load density and different customer mix. It may be resolved by having differential bulk supply tariffs, with higher bulk supply tariffs in distribution areas with low costs and better customer bases.

[13] *Rental Power is a system that has been initiated and promoted by the GoB as an immediate measure to cope with the critical shortage of power.*

3.2 Electricity Pricing in Bhutan

Bhutan is the only country in South Asia with surplus power generation capacity and a power sector that contributes a significant share to its national economy—40% of government revenues, 45% of export earnings, and 25% of gross domestic product in 2009 (ADB, 2010). Bhutan is endowed with rich water resources, along with abundant biomass reserves, both being key energy sources for meeting the country's energy needs.

According to the *Integrated Energy Management Master Plan, 2010*, the Royal Government of Bhutan recognizes the importance of energy and has been taking several measures to achieve its ambitious goal of "electricity for all by 2020"; now revised to 2013 with the Druk Phuensum Tshogpa (DPT) Government in power. The government has formulated *Rural Electrification Master Plan (REMP) 2005*, which provides a road map to achieve 100% electrification in the country within the stipulated time frame. Bhutan is also planning to develop FDI policy for hydropower development, which will encourage IPP and captive power production.

Bhutan Electricity Authority-Tariff Determination Regulation, 2007 provides the electricity tariff determination methodologies in accordance with the *Electricity Act of Bhutan, 2001*. According to this regulation, the electricity tariff is determined on the principle of actual cost of efficient business operation. The government introduced the concept of "Royalty Energy"[14] at the tariff determination.

3.2.1 Power Sector Overview

The power sector in Bhutan is one and the same with the hydropower sector, with more than 99% of electricity being generated by the hydro Bhutan has total installed capacity of 1,480 MW (apart from macro/micro hydro stations). In addition, a Run of the River scheme is being developed under public private partnership which is targeted to be commissioned soon.

The power sector of Bhutan is mandated to meet the electricity requirements of the country both household and industrial, and also to ensure revenue from export of power. Bhutan exports about 75% of its total generation to India in recent years. Average growth rate of electricity is 8%. However, during winter when hydro

[14] *Royalty Energy means the energy to be provided by a generation Licensee to its customers determined in accordance with Tariff Determination Methodology, which is charged at the Royalty Price.*

generation in Bhutan is inadequate to meet its peak demand, Bhutan imports power from India.

Power System of Bhutan is small having less than 300 MW of domestic peak demand in 2013 (BPC, 2013). However, Bhutan has an estimated hydropower potential of around 30,000 MW of which around 23,760 MW is techno-economically feasible for immediate development. Bhutan has committed to an ambitious agenda of developing over 10,000 MW of hydropower capacity by 2020 (CEA, 2012).

3.2.2 Electricity Tariff Methodology

In Bhutan, the cost of supply methodology is used to determine the electricity tariff. The tariff determination is linked with the efficiency and productivity targets. The Tariff Determination Regulation (TDR) of Bhutan is not applicable to import, export and sales of electricity under Power Purchase Agreements. The government of Bhutan introduced the concept of "Royalty Energy" at the tariff determination. According to this concept, this energy (a portion of energy generated by licensees) is to be sold by the generation licensees at discount price, called Royalty Price, to implement transfer of subsidy from generation licensees to customers in accordance with the policy of the Minister.

The cost of supply for a tariff period is determined in consideration of the following components:

- Operating and maintenance costs;
- Depreciation;
- Return on fixed assets, including an allowance for company taxation;
- Power purchases and fuel costs for electricity generation, should either of these be applicable;
- Cost of losses and non-payment of electricity bills;
- Cost of working capital; and
- Any regulatory fees, duties or levies that the Licensee is liable to pay under the Laws of Bhutan.

(a) Determination of Generation Tariff

Presently, Druk Green Power Corporation Limited operates four power plants namely Basochhu Hydropower Plant, Chhukha Hydropower Plant, Kurichhu Hydropower Plant and Tala Hydropower Plant. The Corporation sells its electricity generated to the Power Trading Corporation of India Limited (at rates fixed by the

Royal Government of Bhutan and the Government of India) and to Bhutan Power Corporation Limited for sale in Bhutan (at the rates fixed by relevant authority).

The Tariff Determination Regulation of Bhutan is applicable only for Hydro generation since it has more than 99% hydro electric generation. The total cost of supply for a Generation Licensee in any year is determined in accordance with the following formula:

TC = OM + DEP + RoA + RoWC.

Where
TC= total cost of supply in million Ngultrum;
OM= allowance for operating and maintenance costs in million Ngultrum, including any regulatory and other fees;
DEP= allowance for depreciation of assets in million Ngultrum;
RoA= return on fixed assets in million Ngultrum;
RoWC= return on working capital in million Ngultrum.

The annual energy volume is determined as the Design Energy[15] for each power station adjusted for auxiliary consumption and availability.

$$ENERGY = \sum_i ENERGY_i \times (1 - AUX_i) \times AVAIL_i$$

Where
ENERGY= annual energy volume in any year, in GWh;
$ENERGY_i$= Design Energy for plant "i", in GWh;
AUX_i= allowance for auxiliary consumption at plant "i", in percentage;
$AVAIL_i$= station availability allowance for plant "i", in percentage.

The average cost of supply is calculated as the ratio of the discounted annual costs of supply to the discounted energy volumes. The discounting is applied over the Tariff Period[16] using the weighted average capital cost.

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

[15] *Means the total energy which could be generated in 90% dependable year with 95% installed capacity of the station.*
[16] *Tariff Period means the period, in a designated numbers of years, for which the approved tariffs shall apply.*

Where
AC= average cost of supply for the Licensee in Ngultrum per kWh;
TP= number of years in the Tariff Period;
TC_n= total cost of supply in year "n" in million Ngultrum;
ENERGY= energy volume in year "n" in GWh;
WACC= weighted average cost of capital.

The Royalty Price is determined as the average cost of supply less the ratio of the discounted subsidy amounts to the discounted Royalty Energy. And the discounting is applied over the Tariff Period using the weighted average capital cost. According to the tariff determination regulation, the volume of Royalty Energy in a year should not exceed 15% of the actual annual energy generated by licensees, adjusted for auxiliary consumption as per the norms.

(b) Determination of End-users Tariff

An average price for each end-user group is determined for the tariff period. All end-users connected to a common voltage level (either low or medium or high) comprise one end-user group for the purposes of determining average prices. The average price for a customer/end-user group is determined as the ratio of the discounted costs of supply for that customer group to the discounted electricity sales to that customer group. The discounting is applied over the Tariff Period using the weighted average capital cost and the sales are adjusted for an allowed collection rate.

$$AP_C = \frac{\sum_{n=1}^{TP} COST_{C,n} \Big/ (1+WACC)^n}{\sum_{n=1}^{TP} (SALES_{C,n} \times COLL) \Big/ (1+WACC)^n}$$

Where
AP_c = Average Price for Customer Group "C", in Ngultrum per kWh;
TP = number of years in the Tariff Period;
$COST_{c,n}$ =cost of supply allocated to Customer Group "C" in year "n", in million Ngultrum;
$SALES_{C,n}$ = volumes of electricity sales expected from Customer Group "C" in year "n", in GWh;
COLL = target collection rate set by the Authority for the Licensee, in percentage;
WACC = Weighted Average Cost of Capital for the Licensee, in percentage.

The *cost of supply* for a customer group in a particular year is the sum of energy purchase costs, network costs, the cost of working capital, less any Non-Tariff Revenue, less any subsidies allocated to that customer group.

$$COST_C = (1+LOSS)\times PPP\times SALES_C + IP\times IMPORT\times IMALLOC_C + NETWORK_C + WC_C - REV_C - SUB_C.$$

Where
$COST_C$= cost of supply for Customer Group "C", in million Ngultrum;
$LOSS_C$= sum of technical and commercial losses allocated to Customer Group "C", in percentage;
PPP= Power Purchase Price, in Ngultrum per kWh;
$SALES_C$= sales for the year attributed to Customer Group "C", in GWh;
IP= average import price in Ngultrum per kWh;
IMPORT= volume of electricity imported, in GWh;
$IMALLOC_C$= allocation of import costs to Customer Groups, where $IMALLOC_C$ for the high voltage customer group equals one (=1), and $IMALLOC_C$ for other customer groups equals zero(=0);
$NETWORK_C$= network costs allocated to Customer Group "C", in million Ngultrum;
WC_C= cost of working capital attributed to Customer Group "C", in million Ngultrum;
REV_C= estimated Non-Tariff revenue for the year arising from Customer Group "C", in million Ngultrum;
SUB_C= amount of subsidy allocated to Customer Group "C", in million Ngultrum.

The *Power Purchase Price*, for determination of Average Prices, comprises of the weighted average of purchases from domestic generators and purchases from imports.

$$PPP = \frac{\sum_i [AP \times DOMESTICi]}{\sum_i DOMESTICi}$$

Where
PPP= Power Purchase Price in Ngultrum per kWh;
AP_i= Additional Price for generator "i" in Ngultrum per kWh;
$DOMESTIC_i$= volume of electricity supplied to the Licensee by generator "i", in GWh.

It is to be mentioned here that any energy delivered by a generation Licensee to a distribution Licensee above the Royalty Energy is termed as Additional Energy. And the price for Additional Energy is termed as the Additional Price which is equal to the Average Cost.

The *total annual network costs* of the Licensee comprises the sum of the operating and maintenance allowance, any allowances for fees and levies, the allowance for depreciation, and the allowance for return on assets. And annual network costs allocated to each Customer Group comprises a share of each element of the total annual network costs.

$$NETWORK_C = WACC \times \sum_i [ASSET_i \times AALLOC_{i,C}] + \sum_i [DEP_i \times AALLOC_{i,C}] + \sum_i [OM_i \times OMALLOC_{i,C}] + FEES \times FALLOC_C$$

Where

$NETWORK_C$= network cost allocated to Customer Group "C", in million Ngultrum;

WACC= weighted Average Cost of Capital for the licensee, in percentage;

$ASSET_i$= net historical value of assets in asset category "i", in million Ngultrum;

DEP_i= depreciation allowance for assets in asset category "i", in million Ngultrum;

OM_i= operating and maintenance allowance for cost category "i", in million Ngultrum;

FEES= allowance for fees and levies, in million Ngultrum;

AALLOC= allocation factor to Customer Category "C" for asset-related costs in asset category "i", in percentage;

$OMALLOC_{i,C}$= allocation factor to Customer Category "C" for operating and maintenance costs in cost category "i", in percentage;

$FALLOC_C$= allocation factor for fees, in percentage.

According to the end-users average price determination formula, the table below shows the tariff structure and consumer pattern for different types of customers in Bhutan.

Table 4: Retail Supply Electricity Tariff[17] in Bhutan

Customer Types	*Energy Charge (Nu./kWh)*	*Fixed Charge per month*	*Max. Demand Charge* (Nu./kW/Month)	*Other Charges*
Low[18] Voltage:				
LV Block I- Rural domestic (0-100 kWh)	0	-	-	-
LV Block I- Others (0-100 kWh)	0.98	-	-	-
LV Block II- All (>100-300 kWh)	1.86	-	-	-
LV Block III- All (>300 kWh)	2.46	-	-	-
LV Bulk	2.56	-	-	-
Medium[19] Voltage	1.98	-	115	-
High[20] Voltage	1.67	-	130	-

Source: Bhutan Power Corporation.

As seen in the above table, based on the latest decision of Royal Government of Bhutan to provide up to 100 units free electricity to the LV Block I (rural domestic consumers), the BEA has introduced a new block under Low Voltage Category as LV Block I (rural domestic). However, beyond 100 units consumption by rural domestic consumers, tariff is charged. For the case of high voltage customer 0.114 Nu/kWh wheeling charge is applicable.

3.2.3 Norms of Operation

In Bhutan, determination of the cost of supply and price for each customer group are linked with the achievement of the operational norms, namely, plant availability factor, auxiliary energy consumption, loss allowance and operation and maintenance costs. The table below shows the operational norms for the licensees.

Table 5: Selected Operational Norms in Bhutan

Operating and Maintenance Costs:	
Large Hydro	1.0% to 1.5% of capital costs, adjusted by CPI
Transmission	1.0% of capital costs, adjusted by CPI
Distribution	3.0% of capital costs, adjusted by CPI
Auxiliary Energy onsumption	1.2%

[17] *Approved Tariff (1 October 2013 to 30 June 2014) for the Tariff Period 2013-2016 with effect from 1 October 2013.*
[18] *Domestic Customers up to 11kV.*
[19] *Up to 33kV.*
[20] *Up to 66kV.*

Plant Availability	98%
Technical Losses:	
Low Voltage	12%
Medium Voltage	2.5%
High Voltage	2.0%

Source: Bhutan Electricity Authority-Tariff determination Regulation[21], 2007.

3.2.4 Analyses and Key Findings

Bhutan is a country of having surplus power generating capacity where more than 99% of electricity is being generated from hydro. The power sector contributes a significant share to its national economy. The government has formulated Rural Electrification Plan which provides a road map to achieve 100% electrification in the country within the stipulated time frame.

The Bhutan Electricity Authority (BEA) is the country's electricity regulator and also plays an important role in fixing the domestic tariff rates. *Tariff Determination Regulation, 2007* of BEA provides the electricity tariff determination methodologies in accordance with the Electricity Act of Bhutan, 2001. The electricity tariff in Bhutan is determined on the principle of actual cost of efficient business operation. The tariff determination is linked with the efficiency and productivity targets.

In Bhutan, Druk Green Power Corporation Limited is engaged in generation of hydro electrical energy and for bulk sale of the same to other corporations for distribution and transmission of electricity within Bhutan, and for export of the surplus hydro electrical energy to India. Electricity is being sold mainly to the Power Trading Corporation of India Limited, the sale price of which is fixed mutually by the Royal Government of Bhutan and Government of India. As regards the sale of electricity to the Bhutan Power Corporation Limited, the selling price is determined according to *Tariff Determination Regulation, 2007*.

According to this regulation, the total costs of supply for a generation licensee in any year is determined by adding up O&M cost, depreciation, return on fixed assets and return on working capital. The annual energy volume is determined as the design energy for each power station adjusted for auxiliary consumption and availability. The average cost of supply is then calculated as the ratio of the discounted annual costs of supply to the discounted energy volumes. The government has introduced the concept of "Royalty Energy" at the tariff determination. According to this concept, this energy (shall not exceed 15% of the actual annual energy generated by licensees) is to be sold by generation licensees at

[21] *Updated as of 14th July 2010.*

discount price, called "Royalty Price", to implement transfer of subsidy from generation licensees to customers.

All customers connected to a common voltage level comprise one customer group for the purposes of determining average end-user prices. The average price for a customer/end-user group is determined as the ratio of the discounted cost of supply for that customer group to the discounted electricity sales to that customer group. The cost of supply for a customer group in a particular year is the sum of energy purchase costs, network costs, the cost of working capital, less any Non-Tariff Revenue, less any subsidies allocated to that customer group. Tariff structures of Bhutan ensure affordability for the poor, through the application of low prices for small quantities of electricity. Even based on the latest decision of Royal Government of Bhutan, rural domestic consumers enjoy 100 units free electricity per month. Differentiated tariffs are maintained at different voltage levels of delivery such as low, medium, and high voltage consumers.

3.3 Electricity Pricing in India

India pursues three key objectives in its energy policy: energy access, energy security and climate change. The power sector has been at the centre of India's energy policy. The development of the power sector is closely tied with India's energy policy objectives of universal energy access and energy security. Recognizing that electricity is one of the key drivers for rapid economic growth and poverty alleviation, the nation has set itself the target of providing access to all households (NEP 2005).

There are three main pricing mechanisms in India's power market. First, state generation utilities sell electricity to distribution companies based on long-term contracts at the prices decided by SERCs or PPAs. Second, short-term bilateral contracts are mainly used by traders for inter-state or inter-regional power purchase through open access. These two mechanisms cover most of the electricity sold in India, as 91.1% was sold through long-term contracts and 8.8% through short-term contracts in 2009 (IEA, 2012). A spot market has emerged in 2008 since the opening of two power exchanges.

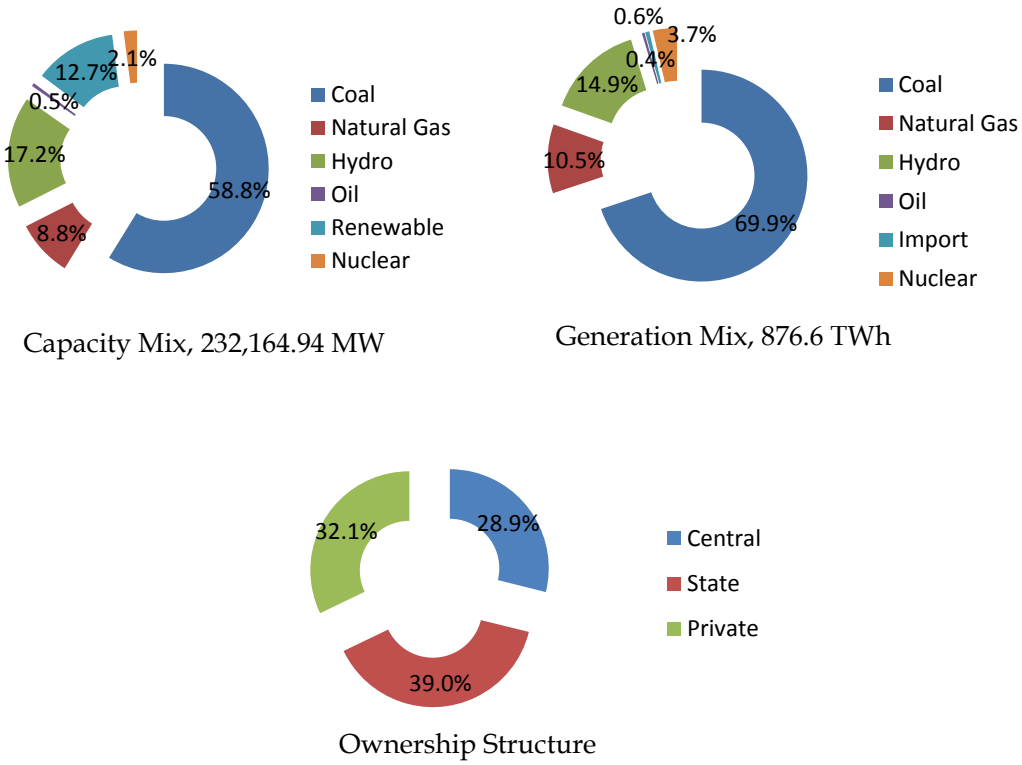
Until economic reforms began in 1991, the power sector was tightly regulated and dominated by vertically-integrated state utilities (IEA 2012). The state electricity boards (SEBs) controlled the entire electricity supply chain from generation, transmission to distribution within a given state. Under the Electricity Regulatory Act of 1998, the Central Electricity Regulatory Commission (CERC) was created and state governments were encouraged to establish their own State Electricity Regulatory Commissions (SERCs) to regulate and rationalize the tariffs. Electricity Act 2003 created a consolidated policy framework for generation, transmission, distribution, trading and consumption of electricity based on market-based mechanisms (Thakur, 2005). The act also mandated the preparation of two key policies: The National Electricity Policy 2005 and The National Tariff Policy 2006. In January 2006, the government of India notified the National Tariff Policy with the objective of ensuring availability of electricity at reasonable and competitive rates and promoting competition and efficiency in operations. Hence, the National Tariff Policy is currently a guide for tariffs.

Section 61(f) of the Electricity Act 2003 states that the Appropriate Commission, for determining the terms and conditions for the determination of tariff, shall be guided inter-alia, by multi-year tariff (MYT) principles. The MYT framework is to be adopted for any tariffs to be determined from April 1, 2006. Further, the National Tariff Policy outlines a detailed MYT framework for generation, transmission and distribution activities.

3.3.1 Power Sector Overview

The total installed capacity in India is 232,164.94 MW as of November 2013 (MoP, 2013). Coal represents around 59% of total installed capacity. Hydro is the second largest source, accounting for about 17% of total installed capacity. According to the Central Electricity Authority (CEA, 2012), the total electricity generation in the country is 876.6 TWh in FY 2011-12, including import from Bhutan & excluding renewable based electricity generation. The share of coal in total electricity generation is around 70%, followed by the hydro with a share of around 15%.

Figure 3: India's Power Generation



Capacity Mix, 232,164.94 MW

Generation Mix, 876.6 TWh

Ownership Structure

Source: CEA, 2012; MoP, 2013.

In India, coal based thermal power generation has been the backbone of power generation due to its availability as compared to other fuels. Coal is likely to remain the main fuel source for the domestic energy market over the next few decades. The Ministry of Power recognizes the fact that private investors have important role to play in the power sector growth. The electricity Act 2003 has provided momentum to the participation of private sector in Generation and Transmission. The private investors have responded to the policy initiatives positively for which, as of November 2013, the contribution of the private sector to the total capacity is about 32%.

3.3.2 Electricity Tariff Methodology

The Central Electricity Regulatory Commission (CERC) of India regulates tariffs of generating companies, owned or controlled by the central government as well as independent power producers that supply more than one state, and inter-state transmission tariffs. It also advises the central government in the formulation of tariff policy. The State Electricity Regulatory Commissions (SERCs) determines the wholesale, bulk and retail tariff for electricity and the tariff for intra-state transmission facilities within its respective state.

In the Indian electricity sector, the Multi-Year Tariff (MYT) framework has been mandated as per the Electricity Act 2003. Further, the National Tariff Policy 2006 outlines a thorough MYT framework for generation, transmission and distribution activities. According to the tariff framework, recovery of different charges by the licensees (generation, transmission and distribution) is linked with the achievement of the set operational norms.

The Multi-Year Tariff framework is based on some elements for calculation of Aggregate Revenue Requirement (ARR)[22] and expected revenue from tariff and charges for Generating Company, Transmission Licensee, Distribution Wires Business and Retail Supply Business. The elements are detailed business plan, forecast of AAR and expected revenue, truing up of previous year's expenses, mechanisms of pass-through as well as sharing of approved gains or losses on account of uncontrollable and controllable factors and annual tariff determination for all licensees for each financial year. The Multi-Year Tariff framework is applicable for determination of tariff for a Generating Company, Transmission Licensee, Distribution Wires Business and Retail Supply Business

(a) Determination of Generation Tariff

Generation Tariff is related to the tariff for supply of electricity to a Distribution Licensee from conventional sources of generation and hydro generation stations of capacity more than 25 MW (existing, new and own[23] generating stations). The tariff for supply of electricity from a thermal generating station comprises of two parts, namely, Capacity Charge and Energy Charge. The Capacity Charge is for recovery of Annual Fixed Cost and the Energy Charge is for recovery of primary fuel cost and secondary fuel cost where applicable. The tariff for supply of electricity from a hydro generating station comprises of two parts, namely, Capacity Charge and

[22] *ARR means the requirement of licensees for recovery, through tariffs, of allowable expenses and return on equity pertaining to its business.*
[23] *Where the Distribution Licensee also undertakes the business of electricity generation.*

Energy Charge. Energy charge for hydro stations is linked to its annual fixed cost and specified design energy.

The Annual Fixed Cost of a generating station comprises of the following components:

- Depreciation;
- Operation & Maintenance Expenses;
- Return on Equity;
- Interest and Finance Charges on Loan Capital;
- Interest on Working Capital;

minus:

- Non-Tariff Income.

Computation and Payment of Annual Fixed Charges and Energy Charges for Thermal Generating Stations:

According to the Gujarat Electricity Regulatory Commission Regulations, 2011 and Central Electricity Regulatory Commissions Regulations, 2009, the total Annual Fixed Charges is computed based on the norms specified under section 3.3.3 of this chapter and recovered on monthly basis under *capacity charge*. The total capacity charge payable for a generating station is shared by its beneficiaries as per their respective percentage share /allocation in the capacity of the generating station. The capacity charge (inclusive of incentive) payable to a thermal generating station for a calendar month is calculated in accordance with the following formulae:

(i) Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year:

AFC x (NDM / NDY) x (0.5 + 0.5 x PAFM / NAPAF) (in Rupees);

Provided that in case the plant availability factor achieved during a financial year (PAFY) is less than 70%, the total capacity charge for the year is:

AFC x (0.5 + 35 / NAPAF) x (PAFY / 70) (in Rupees).

(ii) Generating stations in commercial operation for ten (10) years or more on 1st April of the financial year:

AFC x (NDM / NDY) x (PAFM / NAPAF) (in Rupees).

Where,
AFC = Annual fixed cost specified for the year, in Rupees;
NDM = Number of days in the month;
NDY = Number of days in the year;
NAPAF = Normative annual plant availability factor in percentage;
PAFM = Plant availability factor achieved during the month, in percent;
PAFY = Plant availability factor achieved during the year, in percent.

The Plant availability factor achieved during the month (PAFM) and Plant availability factor achieved during the year (PAFY) is computed in accordance with the following formula:

$$\text{PAFM or PAFY} = 10000 \times \sum_{i=1}^{N} DC_i / \{ N \times IC \times (100 - AUX) \} \%$$

Where,
AUX = Normative auxiliary energy consumption in percentage;
DCi = Average declared capacity (in ex-bus MW);
IC = Installed Capacity (in MW) of the generating station;
N = Number of days during the period i.e. the month or the year as the case may be.

The *Energy Charges* for thermal generating stations covers landed fuel costs and is worked out on the basis of ex-bus energy sent out from the generating station as per the following formula:

Energy Charges (Rs) = Energy Charge Rate in Rs/kWh x Energy (ex-bus) for the month in kWh corresponding to scheduled generation.

Energy Charge Rate (ECR) in Rs/kWh is the sum of the cost of normative quantities of primary fuel, secondary fuel, and limestone consumption, if any, for delivering ex-bus one kWh of electricity and is computed as per the following formula:

$$ECR = \frac{100\{P_p \times (Q_p)_n + P_s \times (Q_s)_n\}}{(100-(AUX_n))} \text{ (Rs/kWh);}$$

Source: GERC Regulations, 2011.

Where;
Pp = Price of primary fuel namely coal or lignite or gas or liquid fuel and lime stone, if applicable, in Rs/kg or Rs/cum or Rs/litre, as the case may be;

$(Qp)_n$ = Quantity of primary fuel required for generation of one kWh of electricity at generator terminals in kg or litre or cum, as the case may be, and shall be computed on the basis of normative Gross Station Heat Rate (less heat contributed by secondary fuel oil and limestone for coal/lignite based generating stations) and gross calorific value of coal/lignite or gas or liquid fuel or limestone as fired;
Ps = Price of Secondary fuel oil in Rs./ml or limestone in Rs/kg;
$(Q_s)_n$ = Normative Quantity of Secondary fuel oil in ml/kWh or limestone in kg/kWh; and
AUX_n = Normative Auxiliary Energy Consumption as % of gross generation.

Computation and Payment of Annual Fixed Charges and Energy Charges for Hydro Generating Stations:

According to the Central Electricity Regulatory Commissions Regulations, 2009, and Gujarat Electricity Regulatory Commission Regulations, 2011 the total Annual Fixed Charges of a Hydro Generating Station is computed based on the norms specified under section 3.3.3 of this chapter and recovered on monthly basis under *capacity charge* and *energy charge*. The total capacity charge is payable by the beneficiaries in proportion to their respective share in the capacity of the generating station. The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month is calculated in accordance with the following formulae:

AFC x 0.5 x (NDM / NDY) x (PAFM / NAPAF) (in Rupees).

Where,
AFC = Annual fixed cost specified for the year, in Rupees;
NDM = Number of days in the month;
NDY = Number of days in the year;
NAPAF = Normative annual plant availability factor in percentage;
PAFM = Plant availability factor achieved during the month, in percent;

The Plant availability factor achieved during the month (PAFM) is computed in accordance with the following formula:

$$PAFM = 10000 \times \sum_{i=1}^{N} DC_i / \{ N \times IC \times (100 - AUX) \} \%$$

Where,
AUX = Normative auxiliary energy consumption in percentage;
DCi = Declared capacity (in ex-bus MW) for the i^{th} day of the month;
IC = Installed Capacity (in MW) of the complete generating station;
N = Number of days in the month.

The Energy Charge for hydro generating stations is payable by every beneficiary for the total energy supplied to the beneficiary during the calendar month on ex-power plant basis, at the computed Energy Charge rate.

Energy Charges (Rs) = Energy Charge Rate in Rs/kWh x Energy (ex-bus) for the month in kWh.

Energy Charge Rate (ECR) in Rupees per kWh on ex-power plant basis is determined up to three decimal places based on the following formula:

$$ECR = AFC \times 0.5 \times 10 / \{ DE \times (100 - AUX) \} ;$$

Where;
DE = Annual Design Energy specified for the hydro generating station, in MWh.

However, there are some exceptions in case actual total generated by a hydro generating station during a year is less than the design energy for reasons those are uncontrollable by the generation company, in case the ECR, as computed by above formula, exceeds eighty paisa per kWh and the actual saleable energy in a year exceeds {DE x (100-UX)/1000} MWh.

(b) Determination of Intra-state Transmission Tariff

Transmission network of India has a two-tier structure: intra-state and local grids are managed by State Transmission Utilities (STUs), while inter-state grids belong to POWERGRID, as a Central Transmission Utility (CTU). Intra-state Transmission Tariff is related to the tariff for access and use of the intra-State transmission system in a State. The annual transmission charges for each financial year of the Control Period provide for the recovery of the aggregate revenue requirement of the Transmission Licensee for the respective financial year of the Control Period, as

reduced by the amount of non-tariff income and income from Other Business, as approved by the Commission and comprising the following component:

Aggregate revenue requirement:

- Return on Equity Capital;
- Interest on Loan Capital;
- Depreciation;
- Operation and maintenance expenses;
- Interest on working capital and deposits from Transmission System Users; and
- Contribution to contingency reserves, if any.

Annual transmission charges = Aggregate revenue requirement, as above,

minus:

- Non-tariff income;
- Revenue from short-term transmission charges; and
- Income from Other Business, to the extent specified in these Regulations.

However, in case of competitively awarded transmission system projects in pursuance of Section 63 of the Electricity Act 2003 and in accordance with guidelines for competitive bidding for transmission, the annual transmission charges shall be as per the annual Transmission Service Charges (TSC) quoted by such competitively awarded transmission projects.

Computation of Intra-state Transmission Tariff:

The aggregate of the yearly revenue requirement for all Transmission Licensees, less the deductions, over the Control Period forms the "Total Transmission Cost" (TTC) of the Intra-State transmission system. It would be recovered from the Long term and Medium term Transmission System Users (TSUs) for the respective year of the Control Period, in accordance with the following Formula:

$$TTC_{(t)} = \sum_{i=1}^{n} (ARR_i - NT_i - O_i - STR_{(t-2)})$$

Where,
TTC(t) = Total Transmission Cost of year (t) of the Control Period;
n = Number of Transmission Licensee(s);
ARRi= Aggregate Revenue Requirement approved by the Commission for i^{th} Transmission Licensee for the yearly period (t) of the Control Period;

NTi = Approved level of non-tariff income for i^{th} Transmission Licensee for the yearly period (t) of the Control Period;
Oi = Approved level of income from other business of the i^{th} Transmission Licensee for the yearly period (t) of the Control Period;
STR = Revenue from short term open access charges earned during previous yearly period (t-2).

The Total Transmission Cost is shared by all long-term and medium-term open access customers on monthly basis in the ratio of their allotted capacities, in accordance with the following formula:

Monthly Transmission tariff= TTC/ (ACs×12) Rs./MW/month

Where ACs= sum of capacities allocated to all long-term and medium-term open access customers in MW.

Table 6: Intra-state Transmission Charges in Gujarat State, India

User Types	***Charge[24], Rs./MW/Day***
Long-term open access	2,720
Short-term open access	680[25]

Source: Annual Report (2009-2010), GERC.

(c) Determination of Distribution Tariff

The Distribution Tariff is related to the tariff that is payable for usage of distribution wires of a Distribution Licensee by a Distribution System User. The wheeling charges for Distribution Wire Business of the Distribution Licensee provide for the recovery of the aggregate revenue requirement and comprising the following component:

- Return on Equity;
- Interest and Finance Charges on Loan Capital;
- Depreciation;
- Operation and maintenance expenses;
- Interest on working capital and deposits from Distribution System Users;
- Contribution to contingency reserves, if any;

minus:

[24] *For FY 2010-11.*
[25] *It is Rs. 170/MW and Rs. 340/MW up to 6 hours and more than 6 hours to 12 hours in a day in one block respectively.*

- Non-Tariff Income; and
- Income from Other Business, to the extent specified in these Regulations;
- Receipts on account of additional surcharge on charges for wheeling.

The Wheeling Charges of the Distribution Licensee is determined by the Commission on the basis of segregated accounts of Distribution Wires Business. However, if the Distribution Licensee is not able to submit audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, the following allocation matrix is applicable:

Table 7: Allocation Matrix for Expenses between Distribution Wire &Retail Supply Business in India, %

Particulars	***Wire Business***	***Retail Supply Business***
Power Purchase Expenses	0	100
Standby Charges	0	100
Employee Expenses	60	40
Administration & General Expenses	50	50
Repair & Maintenance Expenses	90	10
Depreciation	90	10
Interest on Long-term Loan Capital	90	10
Interest on Working Capital and on consumer security deposits	10	90
Bad Debts Written off	0	100
Income Tax	90	10
Transmission Charges intra-State	0	100
Contribution to contingency reserves, if any	100	0
Return on Equity	90	10
Non-Tariff Income	10	90

Source: Gujarat Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2011.

The wheeling charges for the four state owned companies of Gujarat State, India for FY 2010-2011 are shown in the below table.

Table 8: Wheeling Charges in Gujarat State, India

	Charge, Rs./kWh
At 11 KV	12
At 400 V (LT)	40

Source: Annual Report (2009-2010), GERC.

In addition to the above charge, the energy loss is required to be compensated in kind by the open access users.

(d) Determination of Retail Supply Tariff

The Retail Supply Tariff is related to the tariff for retail supply of electricity by a Distribution Licensee to its consumers. The tariff for retail supply by a Distribution Licensee shall provide for recovery of the Aggregate Revenue Requirement of the Distribution Licensee for the financial year, as approved by the Commission and comprising the following:

- Return on Equity;
- Interest and Finance Charges on Loan Capital;
- Depreciation;
- Cost of own power generation / power purchase expenses;
- Transmission charges;
- Operation and Maintenance expenses;
- Interest on working capital and on consumer security deposits;
- Bad debts written off, if any;
- Balance Aggregate Revenue Requirement for Distribution Wires Business after deducting income from wheeling charges payable by Distribution System Users other than the retail consumers getting electricity supply from the same Distribution Licensee.

minus:

- Non-Tariff Income;
- Income from Other Business, to the extent specified in these Regulations;
- Receipts on account of cross-subsidy surcharge.

The tariff for retail supply by a Distribution Licensee is determined on the basis of segregated accounts of Distribution Retail Supply Business.

Table 9: Retail Supply Electricity Tariff[26] in Gujarat State, India

Customer Types	***Energy Charge (Rs./kWh)***	***Fixed Charge (Rs./Month[a];Rs./kW/Month[b];Rs./HP/Month[c])***	***Max. Demand Charge (Rs./kVA/Month)***	***Other Charges***

[26] *With effect from 1st April 2013; Exclusive of electricity duty, tax on sale of electricity, taxes and other charges levied by the Government.*

Supply at Low & Medium Voltage:				
RGP: Residential premises having load up to 6 kWP				
Domestic	3.15–5.2	15-65[a]	-	-
Domestic-Rural[27]	2.75–4.9	15-65[a]	-	-
Domestic-BPL[28]	1.5	5[a]	-	-
GLP	3.8	60[a]	-	-
Non-RGP	4.25-4.55	45-75[b]	-	
Non-RGP Night[d]	2.50	45-75[b]	-	-
LTMD	4.60	85-185[b]	-	Reactive charges
LTMD Night[d]	2.50	85-185[b]	-	Reactive charges
LTP-Lift Irrigation	1.70	40[c]	-	-
AG	0.60	20[c]	-	-
WWSP			-	-
Peak	3.10 – 4.20	15 - 20[c]	-	-
Night[e]	0.75			
Off-peak [f]	0.30			
Street Light	3.95	-	-	-
TMP	4.55	14/kW/day	-	-
Supply at High Tension (3.3KV & above, 3 phase):				
HTP I (≥ 100 kVA)				
Day	4.25-4.55	-	120 - 350	Power factor adjustment charges
Peak1[g]	0.75	-		
Peak 2[h]	0.35	-		
HTP II (≥ 100 kVA): Water Works and Serage Pumping				
Day	4.25-4.55	-	105 - 280	Power factor adjustment charges
Peak1[g]	0.75	-		
Peak 2[h]	0.35	-		
HTP III (≥100 kVA): Temporary Period				
Day	6.50	-	480 - 550	Power factor adjustment charges
Peak1[g]	0.75	-		
Peak 2[h]	0.75	-		
HTP IV (≥100 kVA): Exclusively during night period(10.00 PM to 06.00 AM)				
	2.30		120 - 350	
HTP V (≥100 kVA): Agricultural Irrigation Scheme only				
	1.70	-	40.00	
Railway Traction	4.90	-	160 - 400	Power factor adjustment charges

[27] *Located in areas within Gram Panchayat as defined in the Gujarat Panchayat Act.*
[28] *Below Poverty Line (BPL) Consumer and for the first 30 units only.*

GLP: Educational & others related institutes; Non-RGP: Having aggregate load up to and including 40 kW; LTMD: Having aggregate load above 40 kW and up to 100kW; WWSP: Water works & Sewerage pumping purpose; LTP: Load up to 125 HP for lifting water from surface; AG: Irrigation purpose excluding LTP category; TMP: For temporary period;
[d] 10:00 PM to 6:00 AM; [e] 2200 to 0600 hrs; [f] 1100 to 1800 hrs; [g] 1800 to 2200 hrs; [h] 0700 to 1100 hrs.
Source: Tariff Schedule for FY 2013-14, GERC.

3.3.3 Norms of Operation

In India, recovery of capacity charge, energy charge, transmission & distribution charge and incentive by generating company, transmission licensee and distribution licensee are linked with the achievement of the operational norms, namely, plant availability factor, station heat rate, secondary fuel oil consumption, auxiliary energy consumption, transmission system availability factor. Principally, this is essential to encourage better operating performance. According to the Tariff Policy 2006, the norms of operation have to be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc.

Norms of Operation for Thermal Generating Stations

Normative Annual Plant Availability Factor for full recovery of annual fixed charges is 85% for thermal generating stations. However, there are some exceptions for specific plants where below 85% is also considered.

Gross Station Heat Rate is specific to the particular station & its capacity, fuel types, generation technology and also for existing and new generating stations. The below table shows the station heat rates of some selected existing generating station.

Table 10: Gross Station Heat Rate for Selected Stations in India

kcal/kWh

Stations	*Heat Rate*	
Badarpur TPS	2825	Central Generating Stations
Bakaro TPS	2700	
Gandhar GPS-Combined Cycle	2040	
Gandhar GPS-Open Cycle	2960	
Ukai TPS	2765	Generating Stations of Gujarat[29]
Kutch Lignite TPS	3300	
Dhuvaran CCPP-2	1950	

Source: CERC Regulations, 2009; GERC Regulations, 2011.

[29] *For the year 2012-13 of the control period 2011-12 to 2015-16.*

However, for the new generating units or stations the Gross Heat Rate are:

-Coal-based and lignite fired=1.065xDesign Heat Rate (kcal/kWh)
-Gas-based/Liquid=1.05xDesign Heat Rate of the unit for natural gas and RLNG (kcal/kWh)

Where the Design Heat Rate of a unit means the unit heat rate guaranteed by the supplier at conditions of 100% maximum continuous rating (MCR), zero percent make up, design coal and design cooling water temperature/back pressure.

Secondary Fuel Oil Consumption for some selected generating stations is shown in the below table.

Table 11: Secondary Fuel Oil Consumption for Selected Stations in India

ml/kWh

Stations	***Oil Consumption***	
Coal-based	1.0	Central Generating Stations
Bakaro TPS	2.0	
Lignite-fired based on CFBC Technology	1.25	
Coal-based	1.0	Generating Stations of Gujarat
Lignite-Fired except PFBC Technology	2.0	
Ukai TPS	2.0	
Kutch Lignite TPS	3.0	

Source: CERC Regulations, 2009; GERC Regulations, 2011.

However, for the new generating units or stations of Gujarat state *Secondary Fuel Oil Consumption* are:

-Coal-based: 1.0 ml/kWh
-Lignite-Fired except based on CFBC Technology- 2.0 ml/kWh
-Lignite-Fired based on CFBC Technology- 1.25 ml/kWh

Auxiliary Energy Consumption for some selected generating stations is shown in the below table.

Table 12: Auxiliary Energy Consumption for Selected Stations in India

Stations	***Oil Consumption***	
All Coal-based with some exceptions		Central Generating Stations
200 MW series	8.5%	
300/330/350/500 MW & above (Steam driven boiler feed pumps)	6.0%	

300/330/350/500 MW & above (Electrically driven boiler feed pumps)	8.5%	
Bakaro TPS	9.5%	
Lignite-fired 200 MW and above	9.0%	
Ukai TPS	9.0%	Generating Stations of Gujarat
Kutch Lignite TPS	12.0%	
New Coal based Stations-200 MW Series	8.5%	
Gas Turbine-combined cycle (existing & new)	3.0%	
Gas Turbine-open cycle (existing & new)	1.0%	
New Lignite based- below 200 MW sets	12%	

Source: CERC Regulations, 2009; GERC Regulations, 2011.

According to the Gujarat Electricity Regulatory Commission Regulations, 2011, the *Operations and Maintenance expenses* excluding water charges and including insurance are derived on the basis of average of the actual operation and maintenance expenses for the three years ending 31 March 2010. For the new generating stations of coal, lignite and gas based, the O & M expenses for the year 2012-13 are 15.36, 22.87 and 17.49 lakh Rs./MW respectively.

Norms of Operation for Hydro Generating Stations

Normative Annual Plant Availability Factor (NAPF) for recovery of annual fixed charges is determined as per the following criteria:

Table 13: Normative Annual Plant Availability Factor for Hydro Stations in India

Particulars	***Normative Annual Plant Availability Factor***
Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt	90%
Storage and Pondage type plants with head variation between FRL and MDDL of more than 8%, where plant availability is not affected by silt	Plant-specific allowance to be provided in NAPAF for reduction in MW output capability as reservoir level falls over the months. As a general guideline, the allowance on this account in terms of a multiplying factor may be worked out from the projection of annual average of net head, applying the formula: (Average head / Rated head) + 0.02 Alternatively, in case of a difficulty in making such projection, the multiplying factor may be determined as: (Head at MDDL/Rated head) x 0.5 +0.52
Pondage type plants where plant availability is significantly affected by silt	85%
Run-of-river type plants	To be determined plant-wise, based on 10-day

	design energy data, moderated by past experience where available/relevant

Source: CERC Regulations, 2009; GERC Regulations, 2011.

However, there are some exceptions in NAPAF determination under special circumstances, e.g. silt problem, operating conditions, plant limitations and difficulties in North East Region.

Auxiliary Energy Consumption in case of surface hydro stations are 0.70% and 1.00% for rotating exciters mounted on the generator shaft and static excitation system respectively. And in case of underground hydro these are 1% and 1.2% for rotating exciters mounted on the generator shaft and static excitation system respectively.

According to the Gujarat Electricity Regulatory Commission Regulations, 2011, the *Operations and Maintenance Expenses (O & M)* including insurance are derived on the basis of average of the actual operation and maintenance expenses for the three years ending 31 March 2010. For the new generating stations, O & M for the first year of operation will be 2% of the original project cost (excluding cost of rehabilitation and resettlement works). The O & M expenses for each subsequent year will be determined by escalating the base expenses determined in first year, at the escalation factor of 5.72%.

Norms of Operation for Transmission System

According to the Gujarat Electricity Regulatory Commission Regulations, 2011 and Central Electricity Regulatory Commissions Regulations, 2009, *Normative Annual Transmission System Availability Factor* (NATAF) for full recovery of annual transmission charges is determined as follows:

- AC System 98%
- HVDC bi-pole links 92%
- HVDC back-to-back stations 95%

Norms of Operation for Distribution Wire Business

According to the Gujarat Electricity Regulatory Commission Regulations, *the target Wires Availability* for full recovery of Return on Equity for wires business is as follows:

- Rural Areas 90%
- Towns and Cities 95%

3.3.4 Analyses and Key Findings

The Central Electricity Regulatory Commission (CERC) of India regulates tariffs of generating companies, owned or controlled by the central government as well as independent power producers that supply more than one state, and inter-state transmission tariffs. The State Electricity Regulatory Commissions (SERCs) determines the wholesale, bulk and retail tariff for electricity and the tariff for intra-state transmission facilities within its respective state. This study considers the Gujarat state of India as a case for detail analysis.

With regard to trading and pricing in power market, there are three main mechanisms in India such as long-term contract, short-term contract and spot market. State generation utilities sell electricity to distribution companies based on long-term contracts at the prices decided by SERCs or PPAs. Short-term bilateral contracts are mainly used by traders for inter-state or inter-regional power purchase through open access. A spot market has emerged in 2008.

In the Indian electricity sector, the Multi-Year Tariff (MYT) framework has been mandated as per the Electricity Act 2003. Further, the National Tariff Policy 2006 outlines a thorough MYT framework for generation, transmission and distribution activities. The MYT framework is based on some elements for determination of Aggregate Revenue Requirement (AAR) and Expected Revenue from tariff and charges for Generating Company, Transmission Licensee, Distribution Wire Business and Retail Supply Business. These elements are business plan for each year of the control period, forecast of AAR and expected revenue, truing up of previous year's expenses and revenue, mechanisms for pass-through and sharing of approved gain or losses on account of uncontrollable and controllable factors respectively and finally annual determination of tariff based on approved forecast and results of truing up exercise. According to the tariff framework, recovery of different charges by the licensees (generation, transmission and distribution) is linked with the achievement of the set operational norms.

The tariff for supply of electricity from a generating station comprises of two parts, namely, Capacity Charge and Energy Charge. The Capacity Charge is for recovery of Annual Fixed Costs. The capacity charge and energy charge payable for a generating station is shared by its beneficiaries as per their respective percentage share /allocation in the capacity of the generating station.

The Intra-State Transmission Tariff is related to the tariff for access and use of the Intra-state transmission system in a state. The aggregate of the yearly revenue requirement for all Transmission Licensees, less the deductions, forms the Total

Transmission Cost of the Intra-State transmission system which is shared by all long-term and medium-term open access customers on monthly basis in the ratio of their allotted capacities. The Distribution Tariff is related to the tariff that is payable for usage of distribution wires of a Distribution Licensee by a Distribution System User. The wheeling charges for Distribution Wire Business of the Distribution Licensee provide for the recovery of the aggregate revenue. The Aggregate Revenue Requirement of both the Transmission licensee and Distribution licensee comprises of return on equity, interest and finance charges on loan capital, depreciation, O & M expenses, interest on working capital & deposits and contribution to contingency reserves, if any.

The Retail Supply Tariff is related to the tariff for retail supply of electricity by a Distribution Licensee to its consumers. The tariff for retail supply by a Distribution Licensee provides for recovery of the Aggregate Revenue Requirement of the Distribution Licensee. The Aggregate Revenue Requirement comprises of Return on Equity, Interest and Finance Charges on Loan Capital, Depreciation, Cost of own power generation /power purchase expenses, Transmission charges, O & M expenses, Interest on working capital & on consumer security deposits, Bad debts written off, if any, Balance[30] Aggregate Revenue Requirement for Distribution Wires Business.

CERC and SERCs set the end-user tariff in reflection of fuel cost. Other than the energy, fixed and maximum demand charges, reactive energy charge is applicable for the customers having the aggregate load above 40 kW to 100 kW. Furthermore, power factor adjustment charge and power factor rebate (above 90% power factor) is applicable for the high tension customers. Time of Use tariff is applicable for the selected customers and domestic customers enjoy the life-line tariff for the first 30 units of consumption. Further, there are separate tariff structures for rural consumers. Because of the cross-subsidy structure, Industrial uses are loaded with high tariff to subsidize agriculture and other customers.

[30] *After deducting income from wheeling charges payable by Distribution System Users other than the retail consumers getting electricity supply from the same Distribution Licensee.*

3.4 Electricity Pricing in Pakistan

The power sector in Pakistan has historically been served by two vertically integrated public sector entities. The shortage of electricity in the country motivated the need for restructuring. Therefore, in the early 1990s the Government of Pakistan prepared the strategic plan for restructuring in the electricity sector to improve efficiency, service and quality. Efforts are being made to attract private investment in the power sector. Recognizing the importance of power generation and transmission capacity expansion and efficiency, the government formulated a *Power Policy* and invited independent power producers to invest in generation part of the power sector. The creation of an autonomous regulatory authority was envisaged as a primary step towards achieving the goals of sectoral reforms.

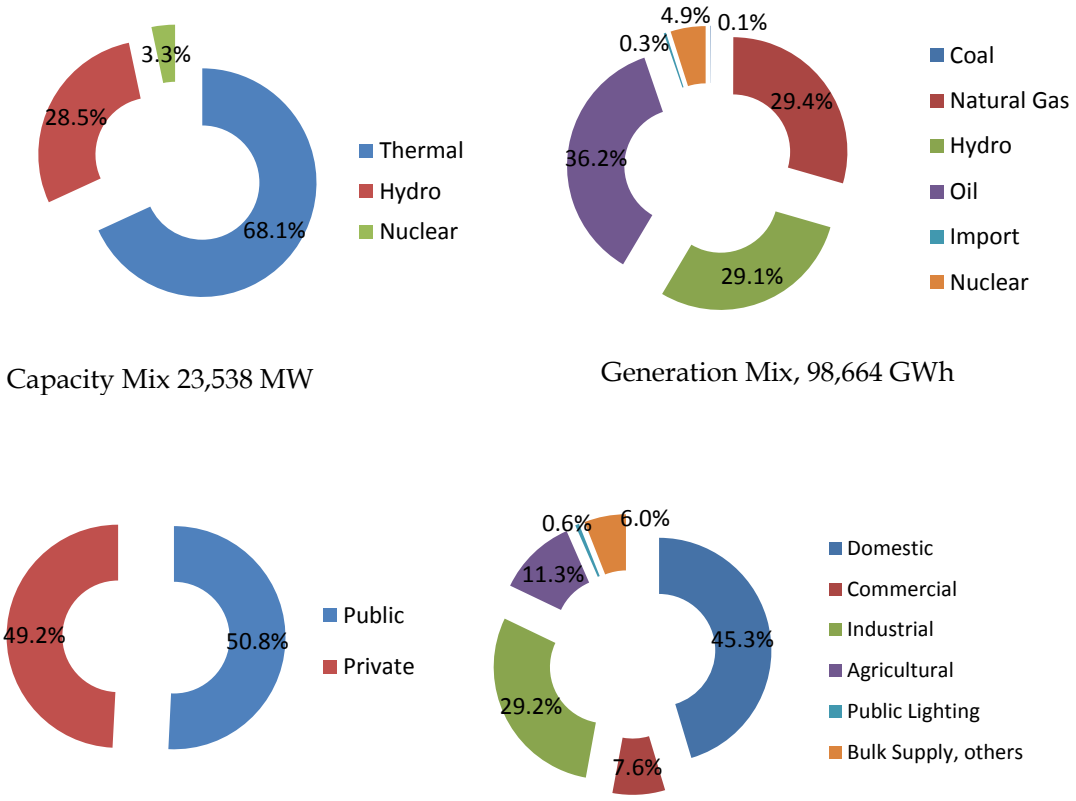
The supply and use of electrical energy in Pakistan is governed by the *Electricity Act, 1910*. The determination of tariff for electric power services is one of the main responsibilities of National Electric Power Regulatory Authority (NEPRA). NEPRA determines the electricity tariff, keeping in view the principles of economic efficiency and service quality, according to the prescribed *Tariff Standards and Procedure Rules, 1998*.

There are two steps in Pakistan's electricity tariff setting process: first, NEPRA determines detailed tariff schedules for the entire fiscal year based on petitions submitted by the Distribution Companies and secondly, the government notifies tariff to be charged by the Distribution Companies. The Tariff for Generation Companies is determined on cost plus basis and in most cases under long term Power Purchase Agreements. The tariff for Transmission Companies is determined on annual cost plus basis. And the Distribution Companies are mostly given tariffs on cost plus basis, whereas multi-year tariffs, performance based, have also been determined for some cases.

3.4.1 Power Sector Overview

The total installed capacity in Pakistan is 23,538 MW as of June 2012 (NEPRA, 2012). Thermal power plants represent around 68% (mostly oil and natural gas) of total installed capacity. Hydro is the second largest source, accounting for about 29% of total installed capacity. According to the State of Industry Report 2012 of NEPRA, the total electricity generation in the country is 98,664 GWh in FY 2011-12, including import. The share of oil (furnace oil and diesel) in total electricity generation is around 36%, followed by the natural gas and hydro with a share of around 29.4% and 29.1% respectively.

Figure 4: Power Generation of Pakistan



Capacity Mix 23,538 MW

Generation Mix, 98,664 GWh

Ownership Structure

Sectoral Consumption, 73,084 GWh

Source: NEPRA, 2012.

In Pakistan, the power production is dominated by thermal power plants; with furnace oil, high-speed diesel and natural gas. The increasing share of thermal electricity generation has increased the financial burden particularly in foreign exchange due to oil import. The share of private sector in the total capacity mix is increasing as compared to the public sector, as of June 2012, the contribution of the private sector to the total capacity is about 49%. Consumption of electricity has grown in all sectors of the economy. Domestic sector is the largest consumer, accounts for 45.3%, followed by Industry, Agricultural and Commercial sector.

3.4.2 Electricity Tariff Methodology

In Pakistan, the procedures and standards in accordance with which tariffs are necessary to be determined, modified or revised are prescribed in the *National Electric Power Regulatory Authority (Tariff Standards and Procedure) Rules, 1998*. NEPRA has been assigned the responsibility for determination, modification or revision of rates, charges and terms and conditions for generation of electric power, transmission, inter-connection, distribution services and power sales to consumers

by the licensees and to recommend these to the Federal Government for notification. NEPRA has the mandate to determine quarterly consumer-end tariff for the Distribution Companies as well as quarterly adjustments in respect of some Distribution Companies having Multi-Year Tariffs[31] and to make adjustments on account of fuel price variation on monthly basis.

Government of Pakistan notifies tariffs to be charged by the Distribution Companies. There are government policy priorities that are linked in these tariff notifications such as uniform tariff policy (same tariff is applicable for a given customer category across the country) and cross-subsidization.

Cost of supply/service of electricity to end consumers comprises of generation cost, transmission cost and distribution margin. Under the current single-buyer regime in Pakistan, electric power is procured and taken in the national pool by Central Power Purchasing Agency (CPPA) within National Transmission and Despatch Company (NTDC) from all the public and private sector generation sources. Cost of generation from all the sources is pooled and transmission charge is added to it for calculating transfer price to be charged to the distribution companies according to the *Transfer Price Mechanism*. Distribution Margin is the cost of running distribution companies.

(a) Determination of Generation Tariff:

All the electric power generated from different sources is procured by the Central Power Purchasing Agency (CPPA) on behalf of Distribution Companies at the rates as per the Power Purchase Agreements. The overall power purchase cost constitutes a *pool price* which is transferred to the Distribution Companies according to a mechanism prescribed by the Authority and notified by the Federal Government.

The tariff for generation companies is determined on a rate of return and in most cases under long term (25-30 years) Power Purchase Agreements. It has two components namely capacity charge and energy charge. The capacity charge and the energy charge for generation companies are calculated with the following formulae:

$$\text{Capacity Charge} = \frac{Interest\ Expenses + Return\ on\ Equity + Depreciation + Fixed\ O\&M\ Expenses}{Dependable\ Generating\ Capacity}$$

[31] *Performance based tariff, determined for FESCO and KESCL.*

$$\text{Energy Charge} = \frac{Fuel\ Cost + Variable\ O\&M\ Expenses}{Total\ Units\ Generated}$$

In addition to the overall cost of generation, the National Transmission and Despatch Company (NTDC) is allowed a Transmission Charge (TC) for its operation and maintenance costs and return on its assets. Finally, the cost of generation plus the Transmission Charge is transferred to the Distribution Companies according to the following *Transfer Price Mechanism* (TPM). NTDC shall charge the Distribution Companies, formed consequently to the unbundle of WAPDA (termed as XWDISCOs) and KESC, a transfer charge for procuring power from generating companies (termed as CPGENCOs) and its delivery to XWDISCOs for billing period as under:

Transfer Charge (XTC) = Capacity Transfer Charge (XCTC) + Energy Transfer Charge (XETC);

$$\text{Capacity Transfer Charge (XCTC)} = \frac{CpGenCap}{XWD} + \text{USCF};$$

Where:

CpGenCap= the summation of the capacity cost in respect of all CPGenCOs in Rs for a billing period minus the amount of liquidated damages received during the month.

XWD= the sum of the maximum demand of the XWDISCOs & KESC in kW during a billing period at all the delivery metering points at which power is received by the XWDISCOs & KESC.

USCF= the fixed charge part of the use of system charges (Transmission Charge) in Rs per kW per month.

$$\text{Energy Transfer Charge (XETC)} = \frac{CpGenE\ (Rs)}{XWUs\ (kWh)}$$

Where:

CpGenE= the summation of the variable charge rate (Rs per kWh) approved for each of the CPGenCOs times the energy in kWh procured from the respective CPGenCO during the billing period.

XWUs= the summation of the energy units (kWh) recorded at the delivery metering point of all the XWDISCOs & KESC during a billing period.

In 2008, the NEPRA Act was amended through the Finance Bill approved by the Parliament, directing NEPRA to determine and notify monthly adjustments in consumer tariffs due to variations in fuel costs, i.e. fuel component in the energy charge portion of Transfer Price charged by NTDC to Distribution Companies. The monthly adjustment on account of fuel cost variation is done in accordance with the following formula:

$$\text{Fuel Price Variation} = \text{Actual Fuel Cost Component} - \text{Reference Fuel Cost Component}$$

Actual fuel cost component is the fuel cost component in the pool price on which the distribution companies will be charged by CPPA in a particular month; and reference fuel cost component is the fuel cost component for the corresponding month projected for the purpose of tariff determination.

(b) Determination of Transmission Charges/Tariff:

National Transmission & Despatch Company (NTDC) was granted Transmission License in 2002 to engage in the exclusive transmission business, pursuant to Section 17 of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997. Under the regime set out in the License, the Company is entrusted to act as System Operator (SO), Transmission Network Operator (TNO), Central Power Purchasing Agency (CPPA) and Contract Registrar and Power Exchange Administrator (CRPEA).

NTDC is allowed to charge *Use of System Charge* (UoSC) to recover the total costs of NTDC and return on equity. Use of System Charge means any charge (fixed and variable) payable by a Distribution Company, Bulk Power Consumer or any other user of the transmission system for Transportation of Power from Generator to Delivery Metering Point and delivery to a distribution company, Bulk Power Consumer or any other. NTDC charges its users for provision of transmission and allied services the following two-part tariff i.e a fixed and variable charge:

$$\text{Fixed Charge} = \frac{(\text{Return on Equity} + \text{Interest Expenses} + \text{Depreciation} + \text{Fixed Operating Expences})}{\text{Maximum Demand}}.$$

$$\text{Variable Charge} = \frac{Variable\ Operating\ Expences}{Total\ Units\ Transmitted} \times \text{LAL Factor}.$$

LAL Factor is a factor for adjustment of losses and Load imposed on the transmission system by a user, which is assumed as one until NEPRA defines individual factors for each transmission user.

Table 14: Wheeling Charges in Pakistan

Fixed Charge	Rs. 102.43/kW/month
Variable Charge	Rs. 0.2367/kWh

Source: NEPRA (FY 2012-2013).

(c) Determination of Distribution Margin

Distribution Margin is the cost of running distribution companies which is determined by the NEPRA. The components forming the distributor margin are:

- Operation & Maintenance Cost;
- Provision for Bad Debts;
- Depreciation;
- Return on Rate Base (RORB);

minus:

- Other Income.

Category-wise consumer-end tariffs are determined by NEPRA so as to fully recover the total Revenue Requirement of the Distribution Companies, based on the share of projected sales of each category. NEPRA keeps the rates of certain categories at a constant level in view of government guidelines. The total units sold are estimated based on the level of losses allowed to each Distribution Companies.

Revenue Requirements of a Distribution Company includes Power Purchase Price and taxes paid which are pass-through parts of tariff plus distribution margin of the company.

Table 15: Retail Supply Electricity Tariff[32] in Pakistan

Customer Types	*Variable Cgarge (Rs./kWh)*	*Fixed Charge (Rs./kW/Month)*	*Max. Demand Charge (Rs./kVA/Month)*	*Other Charges*
Domestic:				
For Sactioned load <5kW				
≤ 50 Units	2.00	-	-	-
For consumption exceeding 50 units				
4 slabs	5.79-15.07	-	-	-
For Sactioned load ≥5kW				
Peak	13.99	-	-	-
Off-peak	8.22	-		
Commercial:				
For Sactioned	14.77	-		

[32] *With effect from May 2012, and notified by the Government of Pakistan.*

load <5kW				
For Sactioned load ≥5kW				
Regular	9.72	400		
Peak	13.2			
Off-peak	8.01	400		
Industrial:				
B1:≤25kW (400/230 V)	10.51	-		
B1 Peak	13.99	-		
B1 Off-peak	8.22	-		
B2:25-500kW (at 400 V)	9.14	400		
B2 Peak	12.77	-		
B2 Off-peak	8.01	400		
B3: ≤5000kW (at 11 kV, 33 kV)				
Peak	12.68	-		
Off-peak	7.75	380		
B4: at 66 kV,1 32 kV & above				
Peak	12.37	-		
Off-peak	7.46	360		
Bilk Supply:				
C1: ≤5 kW	11.5	-		
C1: ≥5 kW	10.35	400		
Peak	13.01	-		
Off-peak	8.01	400		
C2: At 11kV	10.25	380		
Peak	12.6	-		
Off-peak	7.75	380		
C3: At 33kV	10.10	360		
Peak	12.18	-		
Off-peak	7.35	360		
Agricultural:				
SCRAP	10.00	-	-	-
Tube-wells	6.77	120		
Public Light	13.73	-	-	-

Source: NEPRA (State of Industry Report 2012).

3.4.3 Analyses and Key Findings

The National Electric Power Regulatory Authority has the mandate to determine, modify or revise the electricity tariff according to the prescribed *Tariff Standards and Procedure Rules, 1998* and keeping in view the principles of economic efficiency and service quality. Under the current single-buyer regime in Pakistan, electric power is procured and taken in the national pool by Central Power Purchasing Agency (CPPA) from the public and private sector generating stations. Cost of generation from all the sources is pooled and transmission charge is added to it for calculating transfer price to be charged to the distribution companies according to the *Transfer Price Mechanism*.

The Tariff for Generation Companies is determined on cost plus basis and in most cases under long term Power Purchase Agreements. It has two components namely

capacity charge and energy charge. The capacity charge comprises of interest expenses, returns on equity, depreciation and fixed O&M expenses. The energy charge comprises of fuel cost and variable O&M expenses. The tariff for Transmission Companies is determined on annual cost plus basis. National Transmission and Despatch Company, Transmission Licensee, charges it users following the two –part tariff i.e. fixed and variable charge. Distribution Companies are mostly given tariffs on cost plus basis, whereas multi-year tariffs (performance based) have also been determined for some distribution companies.

Distribution margin is the cost of running distribution companies which comprises of the components namely O&M cost, depreciation, return on rate base and provision for bad debts. Category-wise consumer-end tariffs are determined so as to fully recover the total Revenue Requirement of a Distribution Companies, based on the share of projected sales of each category. The Total Revenue Requirements of a Distribution Company includes Power Purchase Price and taxes paid which are pass-through parts of tariff plus distribution margin. There is the provision for monthly adjustments in consumer-end tariffs due to variations in fuel costs.

Cost of supply/service of electricity to end consumers comprises of generation cost, transmission cost and distribution margin. There are two steps in Pakistan's electricity tariff setting process: first, NEPRA determines detailed tariff schedules for the entire fiscal year based on petitions submitted by the Distribution Companies and secondly, the government notifies tariff to be charged by the Distribution Companies. Two government policy priorities prevail in these tariff notifications: (i) uniform tariff policy (same tariff is maintained for a given customer category across the country) and (ii) industrial and commercial customers cross-subsidize domestic and agriculture customers. The actual tariff notified by the Government of Pakistan for implementation is lower than the NEPRA determined tariff. The differential is provided to the distribution companies in the form of subsidy.

Customer categories with small loads are charged on a single tariff. Commercial consumers above 5 kW and industrial customers above 25 kW are charged for maximum demand as well as variable charge for energy. All consumers are also charged a fixed minimum amount even there is no actual consumption. Time of use metering and rates have also been introduced recently. For domestic customers, electricity tariff adopts an incremental block tariff structure where a unit price increases in the amount of electricity use. The reasons for the incremental block tariff structure are to protect lifeline users and to enable cross-subsidization between high volume and low volume consumers.

3.5 Electricity Pricing in Sri Lanka

Recognizing the importance of electricity for rapid economic development and poverty alleviation, successive governments of Sri Lanka have made effort towards the target of providing electricity to all households. National Energy Policy and Strategies of Sri Lanka (2008) spells out the implementing strategies, specific targets and milestones through which the Government of Sri Lanka and its people would endeavor to develop and manage the energy sector in the coming years. This policy recommended the adaptation for an appropriate pricing policy for the energy sector considering important factors such as cost reflectivity, need for targeted subsidies, and competitiveness of locally produced goods and services in the regional and world markets.

Under the Public Utilities Commission of Sri Lanka Act No. 35 of 2002 and the Sri Lanka Electricity Act No. 20 of 2009, the Public Utilities Commission of Sri Lanka (PUCSL) [33] is made responsible for the regulation of the electricity industry. Consequently, the PUCSL plays a pivotal role in the national economy as the watchdog for the economic, safety and technical regulator of the Electricity industry in Sri Lanka. It ensures transparency, fairness, and flexibility for the industry participants while safeguarding consumer rights to achieve policy objectives of Sri Lankan Government.

However, the PUCSL does not make policy. Such provisions are made in the Sri Lanka Electricity Act for the government to provide policy guidance to PUCSL. The Minister of Power and Energy shall have the power to formulate General Policy Guidelines for electricity sector and these guidelines are to be forwarded to the Cabinet of Ministers for approval. Once the policy guidelines have been issued, the PUCSL must take account of them when carrying out their functions.

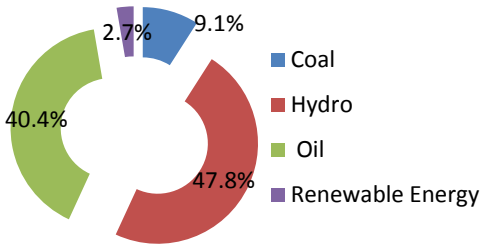
According to the existing *General policy Guidelines on the Electricity Industry for the PUCSL (2009)*, the electricity tariff is formulated by the PUCSL with the objective of supplying electricity to all categories of consumers at reasonable prices while ensuring financial viability of the sector. And average electricity prices to each category of customers have to be gradually made cost effective. There is the provision of lifeline tariff to limited domestic customers and the related subsidy component is financed by the Government grants. However, Ministry of Power and Energy has to be consulted before approving the electricity tariff in order to ensure that public views have been taken into consideration.

[33] *A multi sector regulatory body established under the Parliamentary Act, No. 35 of 2002 for the regulation of several physical infrastructure sectors in Sri Lanka. The PUCSL came into operation in 2003.*

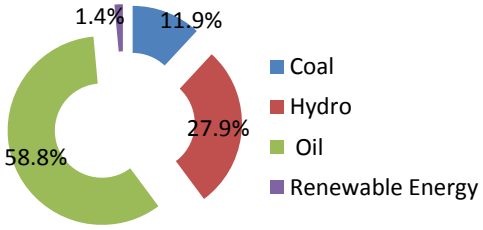
3.5.1 Power Sector Overview

The total installed capacity in Sri Lanka is 3,312 MW as of FY 2012, comprising 2,214 MW of state-owned capacity, 1,098 MW of privately-owned capacity (IPP-thermal, small hydro and renewable). Hydro represents around 48% of total installed capacity. Oil is the second largest source, accounting for about 40% of total installed capacity. According to the Central Electricity Board, the total electricity generation in the country is 11,802 GWh in FY 2012. The share of oil in total electricity generation is around 59%, followed by the hydro with a share of around 28%.

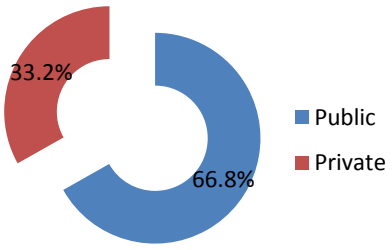
Figure 5: Power Generation of Sri Lanka



Capacity Mix, 3,312 MW



Generation Mix, 11,802 GWh



Ownership Structure

Source: CEB, 2012.

The electricity demand growth rate is 7% to 8% per year. Maximum electricity demand recorded in the year 2012 is 2,146MW. Hydro power is one of the major sources of electricity generation in Sri Lanka and most of the large scale hydro projects have been developed by CEB. The bulk of the economically feasible hydro power potential has already been developed. Electricity sector is moving from the present hydro and oil power position to multiple fuel sources. The first step in this direction is the commissioning of the first 300 MW coal-fired power station.

3.5.2 Electricity Tariff Methodology

A Tariff Methodology (December 2011) is approved by the PUCSL in terms of section 30 of the Sri Lanka Electricity Act, No. 20 of 2009. This is the set of working method in deciding the Bulk Supply Tariffs, the Distribution Tariff and the Retail Supply Tariff. The Bulk Supply Tariffs include the component of the tariff relating to the use of the Transmission System and component of the tariff related to electricity generation. The Distribution Tariff includes the component of the tariff relating to the use of the Distribution System. And the Retail Supply Tariff includes the component of the tariff relating to supply of electricity to end users. Transmission customers will pay only the bulk supply tariff, while other customers will pay a tariff comprising all components.

(a) Determination of Bulk Supply Tariffs

The bulk supply tariffs is calculated by the Electricity Transmission & Bulk Supply Licensee by computing the generation costs, the transmission costs and the supply costs according to the set methodology, and submits them to the commission for approval. In Sri Lanka, Electricity Transmission & Bulk Supply Licensee performs three different activities namely Single Buyer (the single buyer of electricity generated by Generation Licensees), System Operator (the system operator in terms of the Transmission Supplier) and Bulk Supplier (the supplier of electricity in bulk to Distribution Licensees for re-sale and to Bulk Supply Customers).

Bulk Supply Tariffs is the summation of three components:

- Generation tariff;
- Transmission tariff;
- Bulk Supply and Operations Business tariff.

Each component is determined following the established methodology that would be discussed in the later sections. Bulk Supply Tariffs comprises of capacity charge and energy charge. The energy charge varies according to the time intervals as follows:

- Interval 1, from 5:30 AM to 6:30 PM;
- Interval 2, from 6:30 PM to 10:30 PM;
- Interval 3, from 10:30 PM to 5:30 AM.

The ***Forecast Bulk Supply Tariffs***, determined once in every six-month period, are used to determine the end use customer tariffs. These tariffs are passed through to the end use customer tariffs according to the methodology **–Bulk Supply "Pass-**

Through" Tariff that will be discussed in detail in the later section. The Forecast Bulk Supply Tariffs include the forecast for the corresponding six-month period and an adjustment factor to compensate the differences between the forecast and ***Actual Bulk Supply Tariffs***. In the Forecast Bulk Supply Tariffs, there are three components namely (i) Forecast Generation Costs, (ii) Forecast Transmission Tariff and (iii) Forecast Bulk Supply and Operations Business Tariff.

(i) Determination of Forecast Generation Costs

Electricity production is a responsibility of the Generation Licensees. The energy and capacity produced by the generation licensees is purchased by the Single Buyer. Prices for capacity and energy sold by the generation licensees and purchased by the Single Buyer are defined in the Power Purchase Agreements (PPAs). Based on the price formulae in the PPAs and the quantities generated by each generation licensees, the Single Buyer determines the generation cost that is used to calculate the bulk supply tariff. In Sri Lanka, there are four types of PPAs:

- PPAs between Independent Power Producers (IPPs) and the Transmission Licensee;
- PPAs between thermal power plants belonging to Ceylon Electricity Board (CEB) Generation Licensee and the Transmission Licensee;
- PPAs between hydroelectric power plants belonging to CEB Generation Licensee and the Transmission Licensee;
- PPAs with Small Power Producers (SPPs), also known as Small Power Purchase Agreements (SPPAs) and the Transmission Licensee.

The PPAs with IPPs and SPPs are established according to the agreements signed between such IPPs or SPPs and the transmission licensees. For CEB thermal and hydroelectric generation, the CEB generation licensee establishes PPAs with a minimum of five years. The price formula for CEB thermal generation comprises of two parts, namely, the capacity price and energy price. The components of capacity price are:

- Debt service;
- Efficient O & M fixed costs;
- Costs of services provided by CEB generation headquarters.

The components for energy price are:

- Fuel costs (including no load heat rate and incremental heat rate);

- Efficient O & M variable costs;
- Start up costs;
- Others as may be deemed.

For CEB hydroelectric generation, the price formula is one part capacity comprising:

- Debt service;
- Efficient fixed O & M costs including any resource costs;
- Costs of services provided by CEB generation headquarters.

Forecast Generation Costs have the two components namely Capacity Costs and Energy Costs. The Forecast Generation Capacity Cost is the sum of the forecast capacity payments to Generators, based on a monthly simulation of capacity payments under each PPA. The Forecast *Generation Capacity Tariff* is equal to the Forecast Generation Capacity Cost divided by the Forecast System Coincident Peak Demand (MW).

$$GC^{F}_{y,p} = \frac{\sum_{n}^{N} CP^{F}_{y,p,n}}{P^{F}_{y,p}} \quad \left[LKR/MW\right]$$

$GC^{F}_{y,p}$: Forecast Generation Capacity Tariff

$CP^{F}_{y;p;n}$: Forecast capacity payment for year "y", six month period "p" and generator "n"

$P^{F}_{y,p}$: Forecast System Peak Demand for year "y", six month period "p" metered at each point of delivery to Distribution Licensees and Transmission Customers.

"F": Forecast

"N": All generators

Source: PUCSL (December 2011

The Forecast Generation Energy Cost is determined by adding the forecast energy payment to all Generation Licensees according to their forecast energy delivered in all hours and the energy prices stated in each PPA and SPPA. This total Forecast Generation Energy Costs divided by the total forecast energy purchased by distribution licensees and transmission customers provide the Forecast Average *Energy Tariff*.

$$GE^{F}_{y;p} = \frac{\sum_{n}^{N}\sum_{t=1}^{6} EG^{F}_{y,p;n;t} \times EP^{F}_{y;p;n;t}}{\sum_{n}^{N}\sum_{t=1}^{6} EG^{F}_{y,p;n;t}} \qquad \left[LKR/MWh\right]$$

Where,

$GE^{F}_{y;p}$: Forecast Generation Energy tariff for the six-month period "p"

$EG^{F}_{y,p;n;t}$: Forecast Energy Generated for the six month period "p" by Generator "n" during month t

$EP^{F}_{y;p;n;t}$: Forecast Energy tariff according to the PPA or SPPA for the Generator "n" in the month t of the six-month period "p".

"F": Forecast

"N": All Generators

"t": –Month

Source: PUCSL (December 2011).

(ii) Determination of Forecast Transmission Tariff

The Forecast Transmission Tariff is calculated by computing the two components namely Forecast Transmission Capacity Tariff and Forecast Transmission Loss Factor. The Forecast Transmission Capacity Tariff is linked with the Transmission System Allowed Revenue. In accordance with the Tariff Methodology of PUCSL, the Transmission System Allowed Revenue is the revenue that the Transmission Licensee (Bulk Supply and Operations Business) is allowed to collect from the Transmission Users for the use of the Transmission System, excluding connection charges. The Transmission System Allowed Revenue comprises of two components:

- Base Allowed Revenue and
- Large Infrastructure Development (LID) allowances.

Transmission Base Allowed Revenue is calculated based on a Multi Year Tariff System with a cap imposed by the PUCSL on overall revenues during the Tariff Period regardless of the number of Transmission Users, energy transmitted, etc. The Transmission System Allowed Revenue is calculated based on a forecast cash flow for firm discounted at the Allowed Rate of Return on Capital for the Tariff Period, considering initial regulatory asset base (RAB), rolling forward of the initial RAB, (considering minor capital expenditure) for the period, depreciation of existing non-depreciated assets, return on capital, efficient operational expenditure (OPEX) and taxes.

Large Infrastructure Development (LID) is related to the Long-term Transmission Development Plan approved by the PUCSL for the five years period.LID allowances is collected from Transmission System users by adding an allowance to the Transmission Base Allowed Revenue.

The calculation of Transmission System Allowed Revenue is carried out for the period of five years, but there is annual adjustment based on the factors contained in the Revenue Control formula. It is collected in the form of a Transmission Tariff from distribution licensees and transmission customers (Bulk supply). The transmission Tariff is determined on the basis of postage Stamp Methodology in which the Transmission System Allowed Revenue is allocated among Distribution Licensees and Transmission Customers in proportion to their demand at the time of the System Monthly Peak Demand.

The Forecast Transmission tariff comprises of the two components namely Forecast Transmission Capacity Tariff and Forecast Transmission Loss Factor. The Forecast Transmission Capacity tariff (per month for each year of the Tariff Period) is equal to the Transmission System Allowed Revenues divided by the forecast System Peak Demand (MW) for the period according to the Annual Operating Plan, assuming that the total transmission revenues are evenly recovered in each month.

$$TR^{F}_{y;p} = \frac{1}{12}\frac{TSAR_{y}}{P^{F}_{y,p}} \quad \left[LKR/MW\right]$$

Where,

$TR^{F}_{y;p}$: Forecast Transmission Capacity tariff per month for year "y", six month period "p"

$TSAR_{y}$: Transmission System Allowed Revenues year "y"

$P^{F}_{y,p}$: Forecast System Peak Demand for year "y", six month period "p" metered at delivery points to Distribution Licensees and Transmission Customers.

Source: PUCSL (December 2011)

The Forecast Transmission Loss Factor is determined for each Time Interval by dividing the Forecast Total Losses per Time Interval by the Forecast Energy Supplied per Time Interval.

$$TLF^{F}_{y,p,h} = \frac{TL^{F}_{y,p,h}}{\sum_{m}^{M} ES^{F}_{y,p;m;h}}$$

Where

$TLF^{F}_{y,p,h}$: Forecast Transmission Loss Factor, for year "y", six month period "p" and Time Interval "h"

$TL^{F}_{y,p,h}$: Forecast Total Transmission Losses for Time Interval "h", for year "y", six month period "p"

$\sum_{m}^{M} ES^{F}_{y,p;m;h}$: Total Forecast Energy Supplied in year "y", six month period "p" to Distribution Licensee or Bulk Supply Customer "m" in Time Interval "h"

"M": all Distribution Licensees and Bulk Supply Customers

"h": Time Intervals 1, 2 or 3

Source: PUCSL (December 2011)

(iii) Determination of Bulk Supply and Operations Business Tariff

The Bulk Supply and Operations Business Tariff is linked with allowed revenue for the Bulk Supply and Operations Business. This revenue is required for performing the duties of the Single Buyer, the System Operator and the Bulk Supplier. The allowed revenue for the Bulk Supply and Operations Business comprises the following two main components:

- Allowed revenue required for operation of the Bulk Supply and Operations Business;
- Working capital allowance for the Bulk Supply Transactions Account.

The Allowed Revenue is calculated based on a Multi Year Tariff System with a cap on overall revenues during the Tariff Period regardless of the number of Transmission Users, energy transmitted, etc. The calculation of Allowed Revenue is carried out for the period of five years, but there is annual adjustment. The allowed revenue is for the efficient operational expenditure required to perform the operation of the business. Existing assets and capital expenditure is included in the Allowed Revenue for the Transmission Business and not in the Allowed Revenue for the Bulk Supply and Operations Business.

The Bulk Supply Transactions Account is used to settle transactions between the Transmissions Licensee (Transmission) and the other parties such as Transmission Licensee (Bulk Supply Operations Business), Generation Licensees, Distribution Licensees and any Transmission Customers.

In accordance with the equation given below, the Forecast Bulk Supply and Operations Business tariff (for each month for the period) is determined by dividing the Transmission Licensee "Bulk Supply and Operations Business" Allowed Revenues by the Forecast System Peak Demand (MW) according to the Annual Operating Plan. It is presuming that the total Bulk Supply and Operations Business revenues are evenly recovered in each month.

$$BSS^{F}_{y,p} = \frac{1}{12}\frac{BSOB_{y}}{P^{F}_{y,p}} \quad \left[LKR/MW\right]$$

Where,

$BSS^{F}_{y,p}$: Forecast Bulk Supply and Operations Business tariff for six-month period "p" of year "y"

$BSOB_{y}$: Transmission Licensee "Bulk Supply and Operations Business" Allowed Revenue for year "y"

$P^{F}_{y,p}$: Forecast System Peak Demand for year "y", six month period "p" metered at delivery points to Distribution Licensees and Transmission Customers.

Source: PUCSL (December 2011)

Determination of Actual Bulk Supply Tariffs

The Actual Bulk Supply Tariffs is used to compensate for deviations between Forecast and Actual Bulk Supply Tariffs. It has not been passed through to determine the end-user tariffs. The components of Actual Bulk Supply are determined as in the case of Forecast Bulk Supply Tariffs, but for each month. The two-parts (Capacity & Energy), three-interval Resulting Actual Bulk Supply Tariffs are determined according to the following formula:

$$BST^{A}_{t}(C) = GC^{A}_{t} + TR^{A}_{t} + BSS^{A}_{t} \quad \left[LKR/MW\right]$$

$$BST^{A}_{t}(E1) = \left(1 + TLF^{A}_{t,1}\right) \times GE1^{A}_{t} \quad \left[LKR/MWh\right]$$

$$BST^{A}_{t}(E2) = \left(1 + TLF^{A}_{t,2}\right) \times GE2^{A}_{t} \quad \left[LKR/MWh\right]$$

$$BST^{A}_{t}(E3) = \left(1 + TLF^{A}_{t,3}\right) \times GE3^{A}_{t} \quad \left[LKR/MWh\right]$$

Where,

$BST^{A}_{t}(C)$: Actual Bulk Supply Tariff (Capacity) for month "t"

$BST^{A}_{t}(E1)$: Actual Bulk Supply Tariff (Energy in Time Interval 1) for month "t"

$BST^{A}_{t}(E2)$: Actual Bulk Supply Tariff (Energy in Time Interval 2) for month "t"

$BST^{A}_{t}(E3)$ Actual Bulk Supply Tariff (Energy in Time Interval 3) for month "t"

$TLF1^{A}_{t,h}$; $TLF2^{A}_{t,h}$; $TLF3^{A}_{t,h}$: Transmission Loss Factor for Time Intervals 1, 2 and 3 for month "t"

"t": Actual month

$GE1_t^A$; $GE2_t^A$; $GE3_t^A$: Actual Generation Energy Tariff for Time Intervals 1, 2 and 3 for month 't"

GC_t^A; TR_t^A; BSS_t^A: Actual Generation Capacity, Transmission Capacity and Bulk Supply & Operations Business Tariff respectively for month "t"
Source: PUCSL (December 2011)

Resulting Forecast Bulk Supply Tariffs

In accordance with the equation given below, the two-parts, three-intervals resulting Forecast Bulk Supply Tariffs for any given six-month period 'p' is determined which is passed through to determine the end-user tariffs.

$$BST_{y,p}^F(C) = GC_{y,p}^F + TR_{y;p}^F + BSS_{y;p}^F + ..$$

$$\left[\left(\sum_{t=1}^{6} P_{t,p-2}^A \times \left(BST_{y,p-2}^A(C) - BST_{y,p-2}^F(C)\right)\right) \times \frac{1}{P_{y,p}^F}\right] \times (1 + r_{p-1}) \qquad \left[LKR/MW\right]$$

$$BST_{y,p}^F(E1) = \left(1 + TLF_{y,p,1}^F\right) \times GE_{y,p}^F \times k1 + \ldots$$

$$\left[\left(\sum_{t=1}^{6} EG_{t,1,p-2}^A \times \left(BST_{y,p-2}^A(E1) - BST_{y,p-2}^A(E1)\right)\right) \times \frac{1}{EG_{y,1,p}^F}\right] \times (1 + r_{p-1}) \qquad \left[LKR/MWh\right]$$

$$BST_{y,p}^F(E2) = \left(1 + TLF_{y,p,2}^F\right) \times GE_{y,p}^F \times k2 + \ldots$$

$$\left[\left(\sum_{t=1}^{6} EG_{t,2,p-2}^A \times \left(BST_{y,p-2}^A(E2) - BST_{y,p-2}^F(E2)\right)\right) \times \frac{1}{EG_{y,2,p}^F}\right] \times (1 + r_{p-1}) \qquad \left[LKR/MWh\right]$$

$$BST_{y,p}^F(E3) = \left(1 + TLF_{y,p,3}^F\right) \times GE_{y,p}^F \times k3 + ..$$

$$\left[\left(\sum_{t=1}^{6} EG_{t,3,p-2}^A \times \left(BST_{y,p-2}^A(E3) - BST_{y,p-2}^F(E3)\right)\right) \times \frac{1}{EG_{y,3,p}^F}\right] \times (1 + r_{p-1}) \qquad \left[LKR/MWh\right]$$

Where,

$BST_{y,p}^F(C)$: Forecast Bulk Supply Tariff (Capacity)

$BST_{y,p}^F(E1)$: Forecast Bulk Supply Tariff (energy time interval 1)

$BST_{y,p}^F(E2)$: Forecast Bulk Supply Tariff (energy time interval 2)

$BST_{y,p}^F(E3)$ Forecast Bulk Supply Tariff (energy time interval 3)

k1, k2, k3: Ratio of total energy purchased time intervals 1, 2, 3. These factors shall be filed by the Transmission licensee every six months under the guidelines approved by the Commission.

r_{p-1} Average reference Interest rate of six month period "$p-1$" to be defined by the Commission

$EG_{y,1,p}^F$; $EG_{y,2,p}^F$; $EG_{y,3,p}^F$: Forecast energy generated for year "y", six month period "p" in time interval 1, 2, 3.

Source: PUCSL (December 2011).

The allowed capacity costs of generation and energy costs of generation have been combined with the allowed transmission and bulk supply operation business costs to calculate the Bulk Supply Tariffs for sales by the transmission licensee to distribution licensees. According to the above formula, approved 6-month weighted average bulk supply tariffs are shown in the below table. The bulk supply tariff means the average transfer price from Transmission to distribution licensees.

Table 16: Bulk Supply Electricity Tariff[34] in Sri Lanka

	Energy Charge, LKR/kWh	***Capacity Charge,LKR/MW***
Peak	15.78	1,455,358.18
Off-Peak	9.48	
Day	12.61	

Source: PUCSL.

However, in view of the requirement to maintain a Uniform National Tariff and in view of the varying customer mix among distribution licensees, the Bulk Supply Tariff to each distribution licensee is adjusted, to enable each distribution licensee to recover their full allowed revenues.

(b) Determination of Distribution Tariff

Distribution Tariff includes the component of the tariff relating to the use of licensee's distribution system. The Distribution and Supply Licensee is allowed to collect revenue, Distribution Allowed revenue, from the distribution users due to the use of the distribution system (wire business). Distribution Allowed Revenue is calculated based on a Multi Year tariff System with a cap on overall revenues. For each Distribution and Supply Licensee, this revenue is calculated based on a forecast cash flow for the tariff period considering the following:

- Initial Regulatory Asset Base;
- Rolling forward of the initial regulatory asset base, considering the forecast capital expenditure (CAPEX) for the period;
- Depreciation of existing non-depreciated assets;
- Return on capital;
- Efficient operational expenditure (OPEX);
- Taxes.

[34] *For the Period January–June 2013.*

Adjustment mechanisms are also applied to adjust the Distribution Allowed Revenue within the tariff period for inflation and exchange rate variations.

(c) Determination of Retail Supply Tariff

Retail Supply Tariff includes the component of the tariff relating to supply of electricity for end-users. It has the following two components:

- Retail Service tariff;
- Bulk Supply "Pass-through" Tariff.

Retail Service Tariff comprises of all the costs associated to the commercial cycle (meter reading, invoicing and collection), routine meter testing cost and an allowance for bad debt. It is calculated based on Multi Year Tariff System with a cap on average price during the tariff period. Five years is the tariff period and additionally once a year during this period each Distribution and Supply Licensee makes an additional filling to the commission to adjust the tariff based on the Consumer Price Index. In each year of the period, the retail service tariff is calculated by the following formula:

$$RSPC_y = RSPC_{y-1} \times (1 + SLCPI) - DiffRS_y$$

$$DiffRS_y = \left[ARSPC_{y-2} - RSPC_{y-2} \right] \times (1 + r_{y-1})$$

where:

$RSPC_y$	Allowed retail service tariff in year *"y"* (LKR/customer)
$RSPC_{y-1}$	Allowed retail service tariff in year *"y-1"* (LKR/customer)
$SLCPI_y$	Accumulated change in Sri Lanka Consumer Price Index (%) for the year *"y-1"*
r_{y-1}	Average reference Interest rate of year *"y-1"* to be defined by the Commission
$ARSPC_{y-2}$	Actual Retail service tariff (LKR/customer) of the year *"y-2"*.
$RSPC_{y-2}$	Allowed retail service tariff (LKR/customer) of the year *"y-2"*

Source: PUCSL (December 2011).

The allowed tariff includes a forecast of the efficient operational expenditure required to perform the operations related to commercial cycle and related costs.

The Bulk Supply "Pass-through" Tariffs are based on the Bulk Supply Tariffs defined in the earlier sub-section and adapted in order to be applied to retail customers. It consists of two components namely capacity charge and energy charge.

Bulk Supply "Pass-through" Tariffs are differentiated by the voltage. For each voltage level, a Loss Factor is applied which acts as a cap on the level of total losses that the Commission allows to the Distribution and Supply Licensee to be passed

through to customers in each voltage level. The Bulk Supply "Pass-through" Tariffs is calculated by the following formula:

$$PTP_{p,i,v} = BST_p^F(E_i) \times (1 + AL_{p,v})$$
$$CP_{p,v} = BST_p^F(C) \times (1 + CAL_{p,v})$$

where:

$PTP_{p,i,v}$	Allowed energy Pass-through tariff (LKR/kWh) for a six-month period "p" in hourly interval "i" at voltage level "v".
$AL_{p,v}$	Allowed (energy) loss factor (%) at voltage level "v" for the six-month period "p"
$CP_{p,v}$	Allowed capacity Pass-through Tariff (LKR/kVA-month) for the six month period "p"
$CAL_{p,v}$	Allowed (capacity) loss factor (%) for six month period "p" for voltage level "v"

Source: PUCSL (December 2011).

According to the tariff methodology, the retail supply tariffs of Sri Lanka for different customer types are summarized in Table 17.

Table 17: Retail Supply Electricity Tariff[35] in Sri Lanka

Customer Types	*Energy Charge (LKR/kWh)*	*Fixed Charge (LKR/Month)*	*Max. Demand Charge (LKR/Month/kVA)*	*Fuel Adjustment Charge (%)*
Domestic, ≤60 kWh	3 – 4.7	30 - 60	-	25-35
Domestic, ≥60 kWh	10 – 42	90 - 420	-	10-40
Religious	1.9 –9.4	30 - 240	-	-
Industrial-1	12.5	600	-	-
Industrial-2				
Peak	21.0			
Day	11.3	3000	1100	-
Off-peak	7.0			
Industrial-3				
Peak	24.0			
Day	10.5	3000	1000	-
Off-peak	7.0			
Hotel-1	22.0	600	-	15
Hotel-2				
Peak	24.0			
Day	15.0	3000	1100	15
Off-peak	10.0			
Hotel-3				
Peak	23.0			
Day	14.0	3000	1000	15
Off-peak	9.0			
General Purpose-1	19.5-21.5	240	-	25

[35] *With effect from 20 April 2013.*

General Purpose-2			
Peak	25.0		
Day	20.5	3000	1100
Off-peak	14.5		
General Purpose-3			
Peak	24.0		
Day	19.5	3000	1000
Off-peak	13.5		

Source: PUCSL.

There are two domestic categories for which tariffs are different; first category is applicable for monthly consumption of 60 units or less and the second category is applicable for monthly consumption above 60 units. And for each sub-category has different slabs. Fuel Adjustment Charge is applicable only on the energy charge of the monthly electricity bill. In case of Domestic as well as Religious Customers, energy and fixed charges vary according to the monthly consumption slabs starting from 0-30 kWh to greater than 180 kWh. Fuel Adjustment Charge also varies in the case of Domestic Customer according to their monthly consumption slabs while for the case of Religious there is no fuel adjustment Charge. The classifications of each Industrial, Hotel and General Purpose Customer type are based on their delivered voltage level (400/230 Volt and ≥11 KV) and maximum demand (≤42 kVA and >42kVA) of electricity. Time of Use tariffs is applicable for Hotel, General Purpose and Industrial Customer (except General Purpose 1 and Industrial 1). The detail of the Electricity Tariffs of Sri Lanka for different Customer Types along with their classifications is attached in Appendices.

3.5.3 Analyses and Key Findings

The successive governments of Sri Lanka have made effort towards the target of providing electricity to all households. National Energy Policy and Strategies of Sri Lanka recommended the adaptation for an appropriate pricing policy for the energy sector considering important factors such as cost reflectivity, need for targeted subsidies, and competitiveness of locally produced goods and services in the regional and world markets.

The electricity tariff is formulated by the PUCSL; a multi sector regulator came into operation in 2003 with the objective of supplying electricity to all categories of consumers at reasonable prices while ensuring financial viability of the sector. A Tariff Methodology 2010 (and amended in 2011) is approved by the PUCSL in terms of the Sri Lanka Electricity Act. This is the set of working method in deciding the Bulk Supply Tariffs, the Distribution Tariff and the Retail Supply Tariff. In Sri

Lanka, Electricity Transmission & Bulk Supply Licensee performs three different activities namely Single Buyer, System Operator (Transmission) and Bulk Supplier.

In accordance with the Tariff Methodology, the Bulk Supply Tariffs is the summation of generation tariff, transmission tariff and bulk supply & operation business tariff. The prices for electricity sold by the generation licensees and purchased by the single buyer are defined in the Power Purchase Agreements (PPAs). In Sri Lanka, the PPAs with IPPs and SPPs are established according to the agreements signed between such IPPs or SPPs and the transmission licensees. However, the price formulae for Ceylon Electric Board thermal generation comprises of two part (generation and capacity) and it is one part capacity charge for CEB hydroelectric generation. The transmission tariff comprises of two components namely transmission capacity tariff, which is linked with the transmission system allowed revenue, and transmission loss factor. The bulk supply and operations business tariff comprises of two components namely allowed revenue and working capital allowance. The revenue is required for performing the duties of the single buyer, system operator and bulk supplier. Finally, the resulting bulk supply forecast tariffs[36] , adjusted by the actual bulk supply tariffs, are determined which are passed through to the end use customer tariffs.

The Distribution Tariff includes the component of the tariff relating to the use of licensee's Distribution System which is calculated based on multi-year tariff principles with a cap on overall revenues. And the Retail Supply Tariff includes the component of the tariff relating to supply of electricity to end users which has the two components namely retail service tariff and bulk supply "pass-through" tariff. Retail service tariff comprises of all costs associated to the commercial cycle and is calculated based on multi-year tariff system with a cap. The bulk supply "pass-through" tariffs are based on the bulk supply tariff and adopted[37] in order to be applied to retail customers.

Time of use tariffs are given to industrial, general purposes and hotel consumers. Tariffs for domestic and religious customers are based on progressing blocks. The lifeline tariff to domestic customers is limited to a monthly household consumption of 30 kWh. Existing tariff Structure includes subsidies to many consumers such as low consuming domestic consumers, religious institutions and industries. However, the general policy guidelines of Sri Lanka states that the average

[36] *Two parts and three intervals for any given six-month period.*
[37] *A loss factor is applied which acts as a cap on the level of total losses that the commission allows to the distribution and supply licensee to be passed through to customers.*

electricity price to each category of consumers will be gradually made cost reflective.

Sri Lanka is currently in the first five-year "tariff period", in which many of the principles and reforms envisaged in policies and laws were planned to be implemented. The objective was to systematically implement all the provisions in the National Energy Policy, the Electricity Act and the Tariff Methodology by 2015.

Chapter 4
Institutional, Legal and Regulatory Frameworks

4.1 Bangladesh

4.1.1 Institutional Framework

The Ministry of Power, Energy and Mineral Resources (MPEMR) is responsible for overall policy formulation, investment decisions and regulation of the energy sector in Bangladesh. The two divisions under this ministry, namely, the Energy and Mineral Resources Division (EMRD), responsible for developing the oil, gas, and coal sectors to diversify energy supply and improve energy security and the Power Division, responsible for formulating policy relating to power and supervise, control and monitor the developmental activities in the power sector of the country. The Power Division is organized in accordance with its three main responsibilities: electricity generation, transmission and distribution. *Power Cell*, established in 1995, an agency within the Power Division, has the task of enacting the power sector reform program along with the review of tariffs and performance monitoring of the utilities. Under the Power Division, the office of the *Electrical Advisor and Chief Electrical Inspector (EA & CEI)* has been established in order to ensure proper control of life and property in generation, transmission and distribution of electricity. Main responsibility of EA & CEI is to inspect installations, substations and lines as well as to grant license for high tension and medium tension consumers. Besides, it issues license to electrical contractors, engineers and electricians.

The biggest organization under the Power Division is the *Bangladesh Power Development Board (BPDB)* created in May 1972 and was entrusted with the responsibilities of operation, maintenance, and development of generation, transmission & distribution facilities of electricity throughout the country. It has since been relieved of some of its duties by the creation of other entities. The BPDB is responsible for major portion of generation and distribution of electricity mainly in urban areas except Dhaka and West Zone of the country. As part of reform and restructuring, a number of Generation and Distribution companies have been created. The subsidiaries of BPDB are: Ashuganj Power Station Company Ltd. (APSCL), Electricity Generation Company of Bangladesh (EGCB), North West Power Generation Company Ltd. (NWPGCL), Power Grid Company of Bangladesh (PGCB) and West Zone Power Distribution Company Ltd. (WZPDCL). In addition to the government owned power generation companies there are several privately owned small and independent power producers selling electricity to BPDB. At present, the key responsibilities of the BPDB are: Generation of electricity from its

own power plants, power purchase from public and private generation companies as a single buyer, bulk sales of electricity to the utilizes & retail sales of electricity within its 6 distribution zones and preparation of generation & distribution expansion plan.

Rural Electrification Board (REB) was established in 1977 as a semi autonomous government organization and has been providing service to rural member consumers. It is responsible for electrification in rural areas. As of now, there are 70 operating rural electricity co-operatives called Palli Bidyuit Samity (PBS), which bring service to approximately 93,99,134 connections. REB has expanded its distribution networks significantly in past years and has thus made immense contribution in increasing agricultural products and rural development.

Power Grid Company of Bangladesh (PGCB) is a public limited company registered under companies Act and incorporated in November, 1996 to look after the electricity transmission of the country. It is entrusted with the responsibility to operate the national power grid and to develop and expand the same with efficiency. The PGCB also handles the operation, maintenance and development of the transmission system of the country for distribution of generated electricity.

Ashuganj Power Station Company Limited (APSCL) is a public limited company registered under companies Act and was incorporated in June, 2000, as a part of the Power Sector Development and Reform Program of the Government of Bangladesh. It is the second largest power station in the country. At present, it fulfills about 15% of loads throughout the country.

Electricity Generation Company of Bangladesh (EGCB) was incorporated with Register of Joint Stock Companies in February 2004. It has existing power plants at two sites, namely Siddirganj 210 MW Power Station and Haripur 100 MW Power Station. A unit of 2x120 MW peaking power plant has been launched on February 2010. EGCB has started construction process of 360 MW combined cycle power plant and, procurement process of 450 MW combined cycle power plant is going on. EGCB has plans to become a leading electricity generation company of Bangladesh.

Rural Power Company Limited (RPCL) registered as a public limited company under companies Act and was incorporated in December, 1994. It is the first Bangladeshi Independent Power Producer (IPP). Its entire equity investment is mobilized locally. Rural Electrification Board (REB) owns 20% share and the rest 80% is owned by 9 Palli Biddyut Samity (PBS). Mymensingh Power Station (MPS) is one of its power generation plants with a capacity of 210 MW power.

North-West Power Generation Company Limited (NWPGCL) is an enterprise of Bangladesh Power Development Board and was created in 2008. It intends to establish three power plants at different locations in North-Western Zone of Bangladesh. NWPGCL has started the construction process of these power plants (150 MW, 150 MW and 360 MW).

Dhaka Electric Supply Company Limited (DESCO) is the first electric distribution company, registered under companies Act, 1994, and established on November, 1996. DESCO has started functioning after taking over part of the distribution network of DESA which was created in 1990 for the proper management and electrification in Dhaka City and its adjoining districts. Its distribution comprises 220 sq. kms of Dhaka Mega City area namely, Mirpur, Pallabi, Kafrul, Kalyanpur, Cantonment, Gulshan, Banani, Uttara, Uttarkhan, Dakkhinkhan, Badda, Baridhara and Tangi.

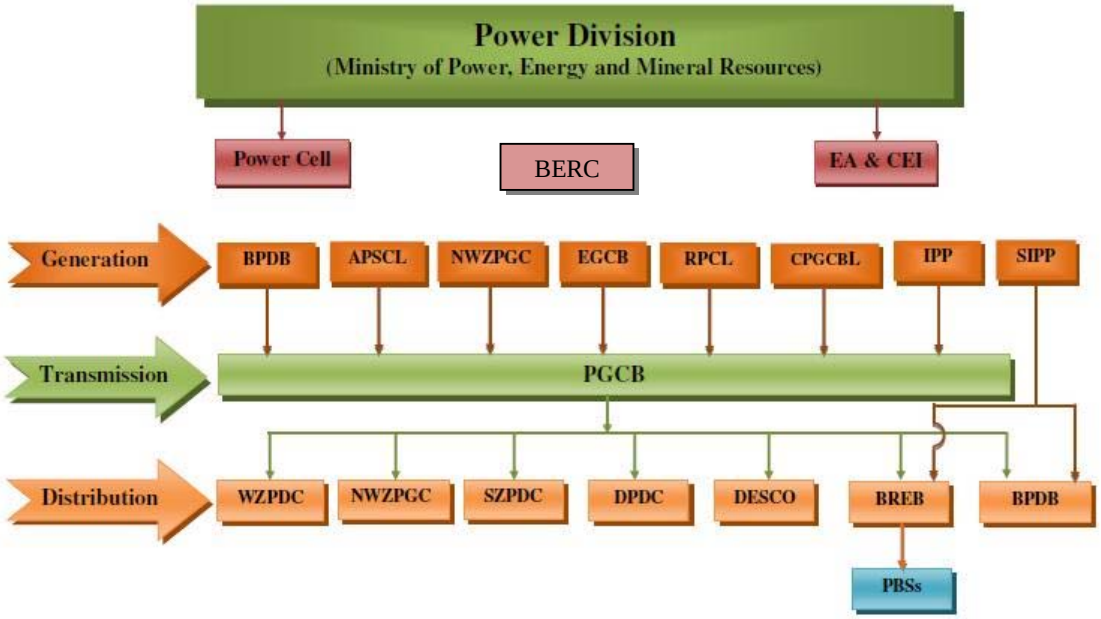
Dhaka Power Distribution Company Limited (DPDC), erstwhile DESA, was registered on October, 2005 and had started its function as a company from July, 2008. DPDC distribution area comprises 350 sq. kms of Dhaka and Narayanganj.

West Zone Power Distribution Company Limited (WZPDCL) was registered on November, 2002. WZPDCL is responsible for electricity distribution to the consumers of west zone, in 21 districts, of country. It has started its function from March 2005.

North West Zone Power Distribution Company Limited (NWZPDCL) was registered on August, 2005. Its distribution area is entire Rajshahi Division. *South Zone Power Distribution Company Limited (SZPDCL)* was established on May, 2008. Both the companies have not started their operation as yet.

Recently, the *Coal Power Generation Company Bangladesh Limited (CPGCBL),* an enterprise of Government of Peoples Republic of Bangladesh, entrusted with the responsibility of best utilization of coal resource and generates electricity to meet the growing demand of the country. It has already started functioning. Another company-*Bangladesh-India friendship Power Company Limited (BIFPCL)*, a 50:50 Joint Venture Company of BPDB, Bangladesh & NTPC, India intends to set up a Coal Based Thermal Power Project in Bangladesh.

Figure 6: Key Players in the Power Sector of Bangladesh



Source: MoPEMR.

4.1.2 Legal and Regulatory Framework

The Electricity Act, 1910 currently governs the power sector of Bangladesh. The Government of Bangladesh formulated and announced the first *National Energy Policy* (NEP) of the county in 1996 to ensure proper exploration, production, distribution and rational use of energy sources to meet the growing energy demand of different zones, consuming sectors and consumers groups on a sustainable basis. *National Energy Policy 1996* provides an overall framework and direction for development of the power sector in Bangladesh. However, with rapid change of global as well as domestic situation it has been decided to update this NEP 1996. The revised draft *National Energy Policy 2004* covers country's non-renewable energy policy, petroleum policy, marginal gas field development policy, renewable and rural energy policy, power policy and rural electrification policy. The objectives of the revised draft National Energy Policy (NEP 2004) are outlined as follows:

- To provide energy for sustainable economic growth so that the economic development activities of different sectors are not constrained due to shortage of energy;
- To meet the energy needs of different zones of the country and socio-economic groups;
- To ensure optimum development of all the indigenous energy sources;
- To ensure sustainable operation of the energy utilities;

- To ensure rational use of total energy sources;
- To ensure environmentally sound sustainable energy development programmes causing minimum damage to environment;
- To encourage public and private sector participation in the development and management of the energy sector;
- To bring entire country under electrification by the year 2020;
- To ensure reliable supply of energy to the people at reasonable and affordable price;
- To develop a regional energy market for rational exchange of commercial energy to ensure energy security.

The National Energy Policy of Bangladesh focuses the tariff policy for Electricity as follows:

- The tariff setting will be consistent with the financial requirements of the power sector institution.
    - Meets operating expenses;
    - Earns adequate return for self investment in future expansion.
- The tariffs will take into account
    - Load management and energy conservation; and
    - Efficiency improvement.
- The GOB's policy objectives will be addressed in tariff setting and recommendations especially on social commitments.
    - Tariff to each consumer class reflects the cost of supply;
    - BPDBs be subsidised by direct transfer from the GOB with the aim of promoting rural development;
    - Gradual withdraw of subsidy for agriculture consumers;
    - Gradual withdraw of subsidy for domestic consumers except those fall in the life line slab (0-100 units presently); and
    - In the interim subsidies to domestic and agriculture consumers be supported through the national budget.
- Automatic price adjustment due to change of the following using a well specified formula:

- Exchange rate;
- Consumer / industrial price index; and
- Fuel price.

According to the revised draft NEP 2004, the tariff structure for rural consumers is to be developed in such a way that the PBS is economically viable, while the rates are within the purchasing power of the rural communities.

The *Bangladesh Energy Regulatory Commission (BERC)* was established on March 13, 2003 through a legislative Act of the Government of Bangladesh, which started functioning from April 27, 2004 with the appointment of two members including the chairman. The Commission has been established with the vision "To make provisions for the establishment of an independent and impartial regulatory commission for the energy sector". The commission has the mandate to regulate Electricity, Gas and Petroleum products for the whole of Bangladesh. Some of the major functions of BERC related to this study include licensing and tariff determination for generation, transmission and distribution of electricity, formulation of a grid code, dispute resolution and promotion of competition in electricity sector. The functions of BERC (Mandated by Law) are as follows:

- Issue, cancel, amend and determine conditions of licenses, exemption of licenses and determine the conditions to be followed by such exempted persons;
- Help ensure efficient use, quality services, determine tariff and safety enhancement of electricity generation and transmission, marketing, supply, storage and distribution of energy;
- Approve schemes on the basis of overall program of the licensee and take decision taking into consideration the load forecast and financial status;
- Extend co-operation and advice to the Government, if necessary, regarding electricity generation, transmission, marketing, supply, distribution and storage of energy;
- Extend co-operation and advice to the Government, if necessary, regarding electricity generation, transmission, marketing, supply, distribution and storage of energy;
- Encourage to create a congenial atmosphere to promote competition amongst the licensees;
- Ensure control of environmental standard of energy under existing laws;
- Ensure appropriate remedy for consumer disputes, dishonest business practices or monopoly;

- Resolve disputes between licensees and between licensees and consumers, and refer to arbitration if necessary;
- Develop uniform methodology of accounting for all licensees to help ensure performance rating on a fair platform;
- Collect, review, maintain & publish statistics of energy;
- Frame codes and standards and make enforcement of those compulsory to ensure quality of services;
- Determine efficiency and standard of the machinery & appliances using energy and ensure through energy audit the verification, monitoring, analysis of the energy data and economic use and enhancement of efficiency on use of energy; and
- Perform any incidental functions if considered appropriate by the Commission for fulfilling objectives of the Act.

In addition to the above acts, rules, regulations and policies, Bangladesh has the following instruments related to power sector:

- *The Rural Electrification Board Ordinance, 1977*;
- *Special Act for quick procurement in Power and Energy Sector;*
- *Sustainable Renewable Energy Developing Authority (SREDA);*
- *Bangladesh Rural Electrification Board (BREB) Act, 2003;*
- *Private Sector Power Generation Policy of Bangladesh;*
- *Renewable energy Policy of Bangladesh;*
- *Small Power Policy;*
- *Vision Statement Policy & Statement of Power Sector Reform;*
- *Bangladesh Private Sector Infrastructure Guidelines;*
- *Remote Area Power Supply Systems Fund;*
- *Power Pricing Framework;*
- *Policy Guidelines for Power Purchase from Captive Power Plant;*
- *Policy Guidelines for Enhancement of Private Participation in the Power Sector, 2008;*
- *Action Plan for Energy Efficiency & Conservation; and*
- *Solar Guide book.*

4.2 Bhutan

4.2.1 Institutional Framework

The energy sector of Bhutan is overseen by the two ministries, namely, the Ministry of Agriculture (MoA) and the Ministry of Economic Affairs (MoEA). The MoA is mainly concerned with the consumption of combustible renewable, such as

biomass. The MoEA oversees policy formulation, planning, coordination, implementation of conventional generation projects, monitoring of consumption trends, exports, and fossil fuel imports. It has several divisions responsible for energy. The Department of Energy manages the establishment of energy policy and planning for the entire energy sector. The Department of Energy is recently bifurcated into three new Departments namely Hydro-met, Hydropower & Power Systems and Renewable Energy. The Department of Trade is responsible for the import petroleum products and for their distribution throughout the country. The Department of Geology and Mines manages and controls the mining of minerals and coal. The Department of Renewable Energy has been established in December 2011 with the mandate to serve as the central coordination agency and the focal point of Bhutan on all matters related to renewable energy development.

Bhutan Electricity Authority (BEA) is the main regulatory agency of the energy sector. The BEA has had the authority to impose differential tariff structures on low, medium, and high voltage consumers. *Bhutan Power Corporation* (BPC) Limited was launched as a public utility on the 1st of July 2002 with the mandate of distributing electricity throughout the Country and also providing transmission access for generating stations for domestic supply as well as export. One of BPC's basic mandate is to not only ensure that electricity is available to all citizens but to also make sure that it is reliable, adequate and above all within the means of all consumers.

Druk Green Power Corporation Limited (DGPC) was incorporated under the Companies Act of the Kingdom of Bhutan on 1st January 2008 with the amalgamation of *Basochhu*, *Chhukha* and *Kurichhu* Hydro Power Corporations, and the *Tala*[38] Hydroelectric Project in April 2009 (Annual Report-DGPC, 2011). Since then, DGPC has successfully ventured beyond the operation and maintenance of these four hydropower plants to the construction of new hydroelectric projects.

4.2.2 Legal and Regulatory Framework

The Bhutan Electricity Authority (BEA) is the country's electricity regulator and also plays an important role in fixing the domestic tariff rates, as specified in the Electricity Act 2001. The BEA was, however, granted full autonomy by the Royal Government from January 2010. The functions of the authority include:

[38] *Tala hydroelectric plant, financed entirely by India, has the installed capacity to produce 1020 MW of power.*

- Develop and implement technical, safety and performance regulations, standards and codes for the electricity sector;
- Develop and implement principles and procedures for tariff setting, and subsidies and economic regulation of domestic sector tariff;
- Issues licenses and monitor licensees as per the provision of the Electricity Act in place; and
- Development and implement Dispute Resolutions Procedures relating to enforcement of Electricity Act, regulations, codes and standards.

The *Electricity Act of Bhutan, 2001* enables the restructuring of the power supply industry and the possible participation of the private sector, by providing mechanisms for licensing and regulating the operations of power companies. The objectives of this Act include, but are not limited to the following:

- Promote a safe and reliable supply of electricity throughout the country;
- Enhance revenue generation through export of electricity;
- Develop the socio-economic welfare of the people;
- Promote economic self reliance of the country through the development of a financially viable and reliable electricity industry;
- Promote development of renewable energy resources;
- Take environmental considerations into account when developing the electricity supply industry; and
- Promote efficiency in management and service delivery.

4.3 India

4.3.1 Institutional Framework

Energy sector of India is managed by a network of ministries, advisory agencies, and regulatory bodies. Until 1992, India's entire energy system was operated under the purview of the Power Ministry. Subsequent restructuring of the energy sector led to the formation of the Ministry of Power (responsible for electricity); the Ministry of Petroleum and Natural Gas; the Ministry of Coal; and the Ministry of New and Renewable Energy. Nuclear power is administered through the department of Atomic Energy. A brief overview of the institutional framework of India's power sector, which is scope of this study, is summarized below.

The Ministry of Power (MoP) is country's apex central government body regulating the electrical sector. It is responsible for planning, formulation, implementation and monitoring of power sector policy. MoP oversees and co-ordinates two statutory

bodies and six Public Sector Undertakings (PSUs), which cover thermal and hydro power generation, transmission and distribution and financing . The ministry is responsible for the administration of the Central Electricity Authority (CEA) and the implementation of India's power-sector legislation. CEA is responsible for the technical co-ordination and supervision of power related programs. It is the responsibility of the CEA to produce India's national electricity plans and to regulate the technical standards required in power sector. In addition to the CEA, the MoP has the authority to oversee the below undertakings that are described in detail:

−The National Thermal Power Corporation (NTPC) is the largest thermal power generation company in India, accounts for around 19% of national electricity capacity and around 29% of total power generation (Charles K. Ebinger 2011). It is a central generation utility to supply electricity to multiple states and to supplement the State Electricity Board-dominated generation sector. It also has a "Maharatna status", which allows it to make an investment decision up to about USD 1 billion (or INR 50 billion) without explicit government approval (NTPC, 2012).

−The North Eastern Electric Power Corporation (NEEPCO) was established to develop the power sector in India's north-east region. The power sector of north-east region still remains underdeveloped though there is high endowment of hydro and natural gas. The NEEPCO has installed capacity of 1 130 MW, representing 55% of installed capacity in the north-east region (NEEPCO, 2012).

−The National Hydroelectric Power Corporation (NHPC) is responsible for developing large hydro, tidal, geothermal and wind based electricity (NHPC, 2012). It operates 14 hydro plants with a total capacity of 5 295 MW (NHPC, 2011).

− The Power Grid Corporation of India (POWERGRID) is mandated to establish and operation of regional and national power grids to facilitate transfer of electric power within and across the regions with reliability, security and on sound commercial principles. POWERGRID, transmits around 45% of India's total electricity, operates a series of dispatch centers across the country.

− The Rural Electrification Corporation (REC) provides financial assistance and loans to state governments for rural electrification projects. REC as a nodal agency received for capital subsidy for the 11th Five-Year Plan (IEA, 2012).

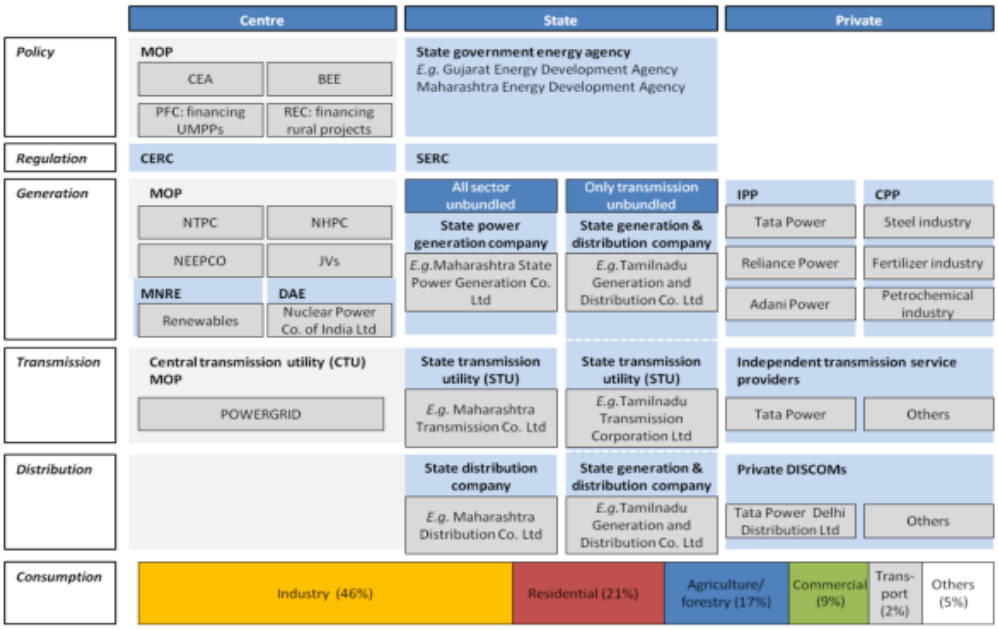
−The Power Finance Corporation (PFC) provides financial assistance to power projects and act as a conduit for foreign investment in the sector. PFC has

also been designated by the MoP as the "nodal agency" for the development of India's ultra-mega projects.

The Bureau of Energy Efficiency (BEE) was established in 2002 as per the Energy Conservation Act of 2001. BEE is responsible for promoting energy saving measures and improves the country's energy intensity. The BEE's main responsibilities include demand side management, labeling and standards, and development of energy auditing and energy performance evaluation mechanism.

Central Electricity Regulatory Commission (CERC) and State Electricity Regulatory Commission (SERC) are the two electricity regulators-one operating at the central level and the other operating at various state levels.

Figure 7: Key Players in the Power Sector of India



Source: IEA, 2012.

4.3.2 Legal and Regulatory Framework

The Electricity Act, 2003 formed a consolidated policy framework for generation, transmission, distribution, trading and consumption of electricity. It encouraged more competition in power sector by unbundling the State Electricity Boards into generation, transmission and distribution utilities. It aims to protect interest of consumers and supply of electricity to all areas, and rationalizing of electricity tariff. The Act de-licenses the thermal generation and captive generation and under this act non-discriminatory open access in transmission was granted to all

generators to ensure fairness. Mandatory metering, stringent punishment of electricity theft and multi-year tariffs were introduced to reduce financial losses of Sate Electricity Boards. With regard to the Tariff Regulations, in the act, it is stated that the appropriate commission shall specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:

- the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;
- the generation, transmission, distribution and supply of electricity are conducted on commercial principles;
- the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;
- safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;
- the principles rewarding efficiency in performance;
- multi year tariff principles;
- that the tariff progressively reflects the cost of supply of electricity and also, reduces cross-subsidies in the manner specified by the Appropriate Commission;
- the promotion of co-generation and generation of electricity from renewable sources of energy;
- the National Electricity Policy and tariff policy.

The Electricity Act, 2003 also mandated to prepare the two key policies namely National Electricity Policy 2005 and National Tariff Policy 2006. **The National Electricity Policy 2005** dealt with issues including rural electrification, recovery of cost of services and targeted subsidies and energy conservation. The National Electricity Policy aims at achieving the following objectives:

- Access to Electricity - Available for all households in next five years;
- Availability of Power - Demand to be fully met by 2012. Energy and peaking
- shortages to be overcome and adequate spinning reserve to be available;
- Supply of Reliable and Quality Power of specified standards in an efficient
- manner and at reasonable rates;
- Per capita availability of electricity to be increased to over 1000 units by
- 2012;
- Minimum lifeline consumption of 1 unit/household/day as a merit good by
- year 2012;
- Financial Turnaround and Commercial Viability of Electricity Sector;

- Protection of consumers' interests.

The National Tariff Policy 2006 aimed to strengthen the financial viability of the sector and to attract investments. The objectives of this tariff policy are to:

- Ensure availability of electricity to consumers at reasonable and competitive rates;
- Ensure financial viability of the sector and attract investments;
- Promote transparency, consistency and predictability in regulatory approaches across jurisdictions and minimise perceptions of regulatory risks;
- Promote competition, efficiency in operations and improvement in quality of supply.

Under the electricity Regulatory Act of 1998, the Central Electricity Regulatory Commission (CERC) was created as an autonomous statutory body. CERC is responsible for setting electricity tariffs for government run power companies and those in the private sector that operate in more than one state. Those operating in a single state fall under the authority of the individual state electricity board. CERC plays advisory functions for the central government in formulation of national electricity policy and tariff policy, and to promote competition, efficiency and investment in electricity industry. It also has the power to issue license for inter-state transmission companies and electricity traders, and the establishment of electricity grid standards. The function of the State Electricity Regulatory Commission, operating at various state levels, is to determine bulk and retail tariffs to customer and regulate the operations of intrastate transmission. Obligations of CERC are:

- Formulate an efficient tariff setting mechanism, which ensures speedy and time bound disposal of tariff petitions, promotes competition, economy, and efficiency in the pricing of bulk power and transmission services, and ensures minimal cost investments;
- The regulation of tariffs of central generating stations;
- The regulation of tariffs of electric power generated and sold across states in a composite package;
- The regulation of interstate transmission tariffs, and facilitation of open access in interstate transmission;
- To issue licenses to persons to function as transmission licensees and electricity traders with respect to their interstate operations;

- To adjudicate disputes involving generating companies or transmission licensees;
- To improve the operations and management of the regional transmission systems through Indian Electricity Grid Code (IEGC), Availability Based Tariff (ABT), etc.;
- To specify and enforce the standards with respect to quality, continuity, and reliability of service by licensees;
- To promote the development of the power market & fix the trading margin in the interstate trading of electricity, if considered necessary;
- To discharge such other functions as may be assigned under the Act.

4.4 Pakistan

4.4.1 Institutional Framework

The Ministry of Water and Power is responsible for the power sector of Pakistan. It monitors the activities relating to electricity generation, transmission and its distribution and the implementation of power projects. It also supervises the overall performances of the power organizations and, serves to coordinate and plan the power sector and formulate policy. The Ministry exercises these functions through its various line agencies and relevant autonomous bodies. Besides, Pakistan Atomic Energy Commission undertakes the projects of nuclear power plants development, operation and maintenance in the country. The National Electric Power Regulatory Authority (NEPRA) is an independent regulator of the power sector which is mandated to ensure that the interests of the investor and the customer are protected through judicious decisions based on transparent commercial principals and that the sector moves towards a competitive environment.

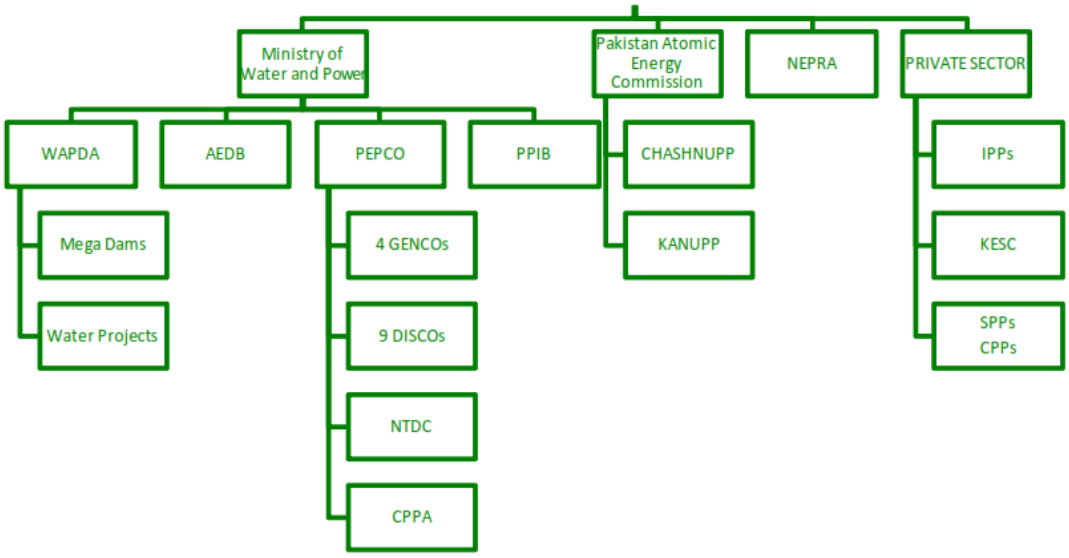
Pakistan's power sector has historically been served by two vertically integrated entities: the Water and Power Development Authority (WAPDA), which was established in 1958 and responsible for supplying electricity across the whole country, except for the greater metropolis of Karachi, which was the responsibility of the Karachi Electric Supply Corporation (KESC), established in 1913. In 1992, WAPDA's Strategy Plan provided the roadmap of the future structure of Pakistan power sector. The strategy plan envisaged staged transition from the monopoly operations of WAPDA to a competitive electric market. The WAPDA was then restructured into decentralized business units. In October 2007, as a part of the overall reform process, all supervision, transmission, distribution, and billing responsibilities related to thermal power were split off from WAPDA into a new

institution, the Pakistan Electric Power Company (PEPCO). At present, WAPDA only retains the water and hydropower development related activities and PEPCO has responsibility for managing the four generation companies (Sothern, Central, Northern and Lakhra), ten corporatized distribution companies (Lahore, Gujranwala, Faisalabad, Islamabad, Multan, Peshawar, Hyderabad, Sukkur, Quetta, and Tribal Areas), and the National Transmission and Despatch Company (NTDC). These entities cover the entire geographical area of Pakistan except Karachi. The first power sector public entity, the Karachi Electric Supply Corporation, has been handed over to the private sector with licenses for generation, transmission, and distribution to the metropolis of the country, Karachi, involving the private sector to improve the power sector performance. In addition to these entities, there are number of IPPs and SPPs are working in Pakistan.

Under the Ministry, Private Power and Infrastructure Board (PPIB), established in 1994, acts as a "One Window Facilitator" to promote private sector participation in the power sector of Pakistan. PPIB facilitates investors in establishing private power projects and related infrastructure, executes Implementation Agreement with Project Sponsors and issues sovereign guarantees on behalf of Government of Pakistan. However, all projects have to be approved for license and tariff by NEPRA.

The Alternative Energy Development Board (AEDB) is responsible to develop national strategy, policies and plans for utilization of alternative and renewable energy resources to achieve the targets approved by the Federal Government in consultation with the Board. It also acts as a forum for evaluating, monitoring and certification of alternative or renewable energy projects and products, and to facilitate power generation through alternative or renewable energy resources.

Figure 8: Key Players in the Power Sector of Pakistan



Source: WB, 2011.

4.4.2 Legal and Regulatory Framework

The power sector of Pakistan is governed by the *Electricity act, 1910*. This law governs the supply and use of electrical energy. It prescribes the procedures for obtaining the licenses to supply electrical energy. In addition, it lays down outline for resolving disputes associated to supply and use of electrical energy.

The National Electric Power Regulatory Authority (NEPRA) was established under an act- *Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997* to function as an independent regulator and ensure transparent, competitive, commercially-oriented power market in Pakistan. As per Section 7(1) and 7(2) of NEPRA Act, the Authority shall be exclusively responsible for:

- Grant licenses for generation, transmission and distribution of electric power;
- Prescribe procedures and standards for investment programmes by generation, transmission and distribution companies;
- Prescribe and enforce performance standards for generation, transmission and distribution companies;
- Establish a uniform system of accounts by generation, transmission and distribution companies;
- Prescribe fees including fees for grant of licenses and renewal thereof;

- Prescribe fines for contravention of the provisions of this Act;
- Review its orders, decision or determinations;
- Settle disputes between the licensees;
- Issue guidelines and standards operating procedures; and
- Perform any other function which is incidental or consequential to any of the aforesaid functions.

Under Section 7(3-a) of NEPRA Act, the Authority shall determine tariff, rates, charges and other terms and conditions for supply of electric power services by the generation, transmission and distribution companies and recommend to the Federal Government for notification. NEPRA determines electricity tariff, keeping in view the principles of economic efficiency service quality according to the *National Electric Power Regulatory (Tariff Standards and Procedure) Rules, 1998.* Under Section 17(3) of NEPRA Rules, 1998, tariffs shall be determined, modified or revised on the basis of and in accordance with the following standards, namely:-

- Tariffs should allow licensees the recovery of any and all costs prudently incurred to meet the demonstrated needs of their customers, provided that, assessments of licensees, prudence may not be required where tariffs are set on other than cost - of - service basis, such as formula-based tariffs that are designed to be in place for more than one years;
- Tariffs should generally be calculated by including a depreciation charge and a rate of return on the capital investment of each licensees commensurate to that earned by other investments of comparable risk;
- Tariffs should allow licensees a rate of return which promotes continued reasonable investment in equipment and facilities for improved and efficient service;
- Tariffs should include a mechanism to allow licensees a benefit from, and penalties for failure to achieve, the efficiencies in the cost of providing the service and the quality of service;
- Tariffs should reflect marginal cost principles to the extent feasible, keeping in view the financial stability of the sector;
- The Authority shall have a preference for competition rather than regulation and shall adopt policies and establish tariffs towards that end;
- The tariff regime should clearly identify inter-class and inter-region subsidies and shall provide such subsidies transparently if found essential,

with a view to minimizing if not eliminating them, keeping in view the need for an adequate transition period;

- Tariffs may be set below the level of cost of providing the service to consumers consuming electric power below the consumption levels determined for the purpose from time to time by the Authority, as long as such tariffs are financially sustainable;
- Tariffs should, to the extent feasible, reflect the full cost of service to consumer groups with similar service requirements;
- Tariffs should take into account Government subsidies or the need for adjustment to finance rural electrification in accordance with the policies of the Government;
- The application of the tariffs should allow reasonable transition periods for the adjustments of tariffs to meet the standards and other requirements pursuant to the Act including the performance standards, industry standards and the uniform codes of conduct;
- Tariffs should seek to provide stability and predict-ability for customers; and
- Tariffs should be comprehensible, free of misinterpretation and shall state explicitly each component thereof.

As per Section 35 of NEPRA Act and article 16 of the National Transmission and Despatch Company (NTDC) licensee, the NTDC is responsible for developing and implementing a Grid Code. NTDC acts as a Central Power Purchasing Agency (CPPA) for procurement of power from thermal power generating companies, hydroelectric power plants and IPPs on behalf of Distribution Companies, for delivering through high voltage network. A policy for Power Generation Projects was announced in 1994 to attract private investment which was subsequently revised in 1998 and 2002.

In addition to the above acts, rules and regulations, NEPRA has the following regulatory instruments:

- *Application Modification Procedure Regulations, 1999*: to standardize the manner for submitting applications and filling petitions to NEPRA;
- *Licensing Generation Rules, 2000*: to streamline the process for becoming a licensee under NEPRA Act;

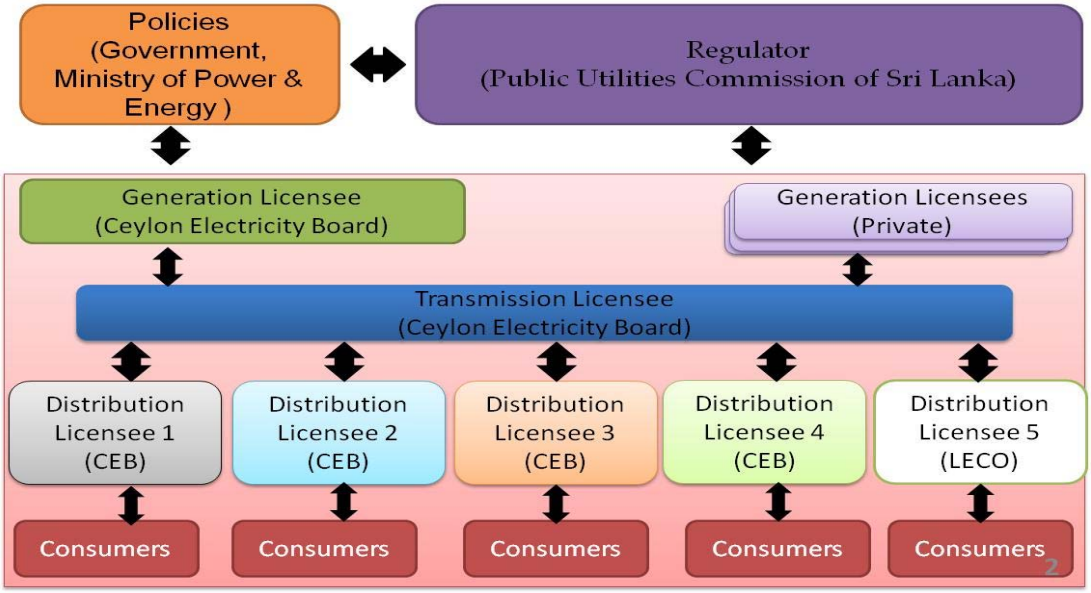
- *National Electric Power Regulatory Authority Licensing (Distribution) Rules, 1999 and Eligibility Criteria for Consumers of (Distribution) Companies, 2003*: to regulate the process of acquiring licenses by distribution companies;
- *Interim Power Procurement (Procedures and Standards) Regulation, 2005*: to streamline the manner for acquiring permission for sale of power to transmission and distribution companies;
- *Performance Standards (Distribution) Rules, 2005*: to provide the standards of performance for distribution companies;
- *Performance Standards (Transmission) Rules, 2005*: to provide the standards of performance for transmission companies; and
- *NEPRA Uniform System of Accounts Rules, 2009*.

4.5 Sri Lanka

4.5.1 Institutional Framework

The energy sector of Sri Lank is overseen by two ministries, the Ministry of Power and Energy (MoPE) and the Ministry of Petroleum and Petroleum Resources Development. The Ministry of Power and Energy is concerned mainly with the implementation of the government policies related to Electricity and Energy Sectors. The *Ceylon Electricity Board (CEB)*, under the purview of the Ministry of Power & Energy, is the owner and operator of the national electricity grid. It owns all large hydropower stations and 50% of the thermal power generation capacity in Sri Lanka. The remainder of the thermal-based power generation is owned by private players. CEB caters to 85% of the consumers connected to the national grid and the *Lanka Electricity Company (Pvt.),* a private limited company registered under the Companies Act No.17 of Sri Lanka, distributes electricity to rest of the consumers mainly urban and suburban areas. *Lanka Electricity Company* is a state owned private company established in 1984. IPPs and small hydro developers entered the industry in the mid 1990s when the government decided to open the generation sector to private investors. Lanka Coal Company (Private) Limited (LCC) was incorporated on January 2008 under the Companies Act, No7 of 2007 subsequent to a Cabinet Decision to establish an organization for procurement of Coal for Coal fired thermal power plants in Sri Lanka. Sri Lanka Energies (Pvt.) Ltd had been incorporated in 1st quarter of 2011. This has started operations in January 2012. The main objective of this company is Renewable Energy Development among other objectives.

Figure 9: Key Players in the Power Sector of Sri Lanka



Source: "Electricity Sector in Sri Lanka in Regulatory Perspective" by Damitha Kumarasinghe.

4.5.2 Legal and Regulatory Framework

National Energy Policy and Strategies of Sri Lanka, published in June 2008 in Gazette Extraordinary No. 1553/10 of 10th June 2008, describe the broad policies of the Government. The Public Utilities Commission of Sri Lanka (PUCSL) plays a pivotal role in the national economy as the watchdog for the economic, safety and technical regulator of the Electricity industry in Sri Lanka. Established by The Public Utilities Commission of Sri Lanka Act No. 35 of 2002 by the Parliament of Sri Lanka, the Public Utilities Commission of Sri Lanka performs a vital role as a multi-sector supervisory body regulating certain physical infrastructure industries in the country. The PUCSL came into operation in 2003.

Recognizing effective regulation, the Government of Sri Lanka (GoSL) enacted the Sri Lanka Electricity Act, No. 20 of 2009 which empowers the Public Utilities Commission of Sri Lanka (PUCSL) as the regulator of the generation, transmission, distribution, supply and use of electricity in Sri Lanka. The PUCSL shall perform the role of an economic, technical and safety regulator for the electricity industry in Sri Lanka ensuring transparency, fairness, and flexibility for the industry participants whilst safeguarding the consumer rights to achieve GoSL policy objectives.

In accordance with the Sri Lanka Electricity Act, No. 20 of 2009, the Ministry of Power and Energy shall have the power to formulate General Policy Guidelines in

respect of the electricity industry and these guidelines are to be forwarded to the Cabinet Ministry for approval. With regard to the electricity tariff the General Policy Guidelines are as follows:

- A tariff policy shall be formulated by the PUCSL with the objectives of supplying electricity to all categories of consumers at reasonable prices while ensuring financial viability of the sector. Fundamental changes to the tariff structure may be necessary to take into account the development of the industrial sector while giving due recognition to the sector;
- Average electricity price to each category of consumers will be gradually made cost reflective. A conducive environment will be created to fully utilize the Demand Side Management (DSM) opportunities arising from this change;
- The lifeline tariff to domestic customers will be limited to Samurdhi Beneficiaries[39] and to a monthly household consumption of 30kWh. The related subsidy component estimated at 50% of the cost of supply will be fully financed through Government grants;
- Electricity generation prices at bulk purchase points will be set as stated in the Power Purchase Agreements and the cost of transmission, distribution and supply will be regulated ensuring fairness to both consumers and licensees. Consumers and all other stakeholders, other than Government, will be given opportunities to present their views at a public hearing. The Ministry of Power and Energy shall be consulted before approving the tariff in order to ensure that public views have been taken into consideration on before finalizing the tariff;
- Notwithstanding above, licensees will be compensated adequately for all reasonable costs, if they are compelled to sell electricity to any category of consumers at subsidized prices, on directives by GoSL.

[39] *In 1994, the Samurdhi (or Prosperity) Programme was launched by the newly elected Sri Lankan Government as a national strategy to alleviate poverty, and the Samurdhi Ministry was established. This programme covers one-third of the entire population of Sri Lanka, about 1.2 million poor families.*

Chapter 5
Concluding Remarks

This study focuses on the prevailing electricity pricing practices in the selected SAARC Member States, with regard to price determination methodologies, related institutional arrangements and regulatory setups. The theoretical aspects of electricity pricing and objectives of pricing are also described. The study covers mainly generation, transmission, distribution and retail supply tariff determination methodologies adopted by the Member States. Under this study, the Member States namely Bangladesh, Bhutan, India, Pakistan and Sri Lanka are considered. The major findings in this study are summarized below.

Electricity pricing practices play significant roles in economic development, technology development and energy consumption behavior. Electricity tariffs need to signal to both consumers and present or prospective suppliers both when to use or supply electricity and why one location or another is better suited for a new generation plant. Simultaneously, tariffs need to reflect the country's energy policy priorities. In actual fact, the decision on tariff design of a country is a complex issue. It requires the government/regulator to make balance among various interests which are conflicting in nature. The consumers seek a low price. The suppliers need high profit. The country itself needs a tariff with high economic yield and the environment needs an environmentally sustainable energy system. Higher tariff may result into loss of consumer welfare. On the other hand, un-reasonably lower tariff may leave the supplier with deficit revenue and lead to poor quality of service. The challenge towards a rational tariff is to attain justifiable tariff to all stakeholders.

There are certain principles/objectives that need to be followed while determining electricity tariff. The objectives are: (i) Principle of economic efficiency; (ii) Principles relating to fairness and equity; (iii) Financial viability of the sector; (iv) Simple tariff structure; and (v) Other economic and political requirements. Since these objectives often conflict with one another, it is necessary to accept certain trade-offs on designing electricity tariff. Designing a justifiable tariff and its implementation can serve multiple objectives simultaneously. In order to follow these principles/objectives, there are various pricing approaches/methods available for the consideration such as marginal cost pricing, cost-plus pricing, peak-load pricing, two-part tariff, price cap and performance based approach. Each of these has its own advantages and disadvantages. Selection of appropriate approach for a particular country depends upon a number of parameters such as

availability of adequate and reliable information, responsiveness of market, degree of competitiveness and other socio-economic factors.

Tariff setting objectives of selected SAARC Member States are mix of objectives including cost recover & social concern, but aiming to reach efficient tariff. The tariff setting policy of Bangladesh stipulates the achievement of the cost reflective tariff and generates a surplus to expand operation while maintaining a least cost to the consumers. The policy addresses social commitments as well. The electricity tariff in Bhutan is based on the principle of actual cost of efficient business operation and affordability to the poor. The Government of India notified the National Tariff Policy with the objective of ensuring availability of electricity at reasonable and competitive rates and promoting competition and efficiency in operations. The tariff determination policy of Pakistan is based on the principle of economic efficiency and service quality. In Sri Lanka, electricity tariff is formulated with the objective of supplying electricity to all categories of consumers at reasonable prices while ensuring financial viability of the sector.

Most of the selected Member States have Tariff Methodology, formulated by respective regulator, wherein set of working methods in determining the generation, transmission, distribution and retail supply tariff has been described. *Bangladesh Energy Regulatory Commission (Electricity Generation Tariff) Regulation 2008* has been adopted by BERC which provides the methodologies for determination of generation tariff. BERC has also developed draft transmission and distribution tariff methodologies. *Tariff Determination Regulation 2007* of BEA provides electricity tariff determination methodologies in accordance with the electricity Act of Bhutan. In India, under the Electricity Regulatory Act of 1998, the Central Electric Regulatory Commission was created and state governments were encouraged to establish their own State Electricity Commissions' to regulate and rationalize the tariffs. *CERC Regulations 2009* and *SERC Regulations* for each state are the guide for the tariff determination. The NEPRA of Pakistan determines the tariff according to the prescribed *Tariff Standards and Procedure Rules, 1998*. In Sri Lanka, *Tariff Methodology 2010 (and amended in 2011)* guides in deciding the bulk supply tariff, the distribution tariff and the retail supply tariff.

Cost of electricity supply to the end customers comprises of generation cost, transmission cost and distribution margin. The total cost of supply is segregated into various cost components. Irrespective to the use of particular pricing method/approach by the tariff setting authority, calculation of tariff is an important exercise to assess the financial performance of the utilities. In case of a generation company, the major cost components of tariff are fuel cost,

transportation cost of fuel, employee cost, repair & maintenance cost, depreciation cost, pollution control expenses, taxes and return on capital. Depreciation, salary of employees, repair & maintenance, return on capital, metering etc. are the major cost components for a transmission company. Similarly the major components of a distribution company are power purchase cost, employee cost, operation & maintenance cost, depreciation cost, energy losses, taxes and return on capital. After examining these various cost components, the total cost of supply (Annual Revenue Requirement) is calculated by the regulator. Member States have been open to private investment in generation sector. The structure of the electricity generation sources of selected Member States comprises of mostly public generation, IPP purchases and rental power plants. The tariff for generation companies is determined on cost plus basis and in most cases under power purchase agreements. In generation sector, a Single-Buyer model has been adopted by Bangladesh, Bhutan, Pakistan and Sri Lanka where the Single-Buyer (Bangladesh-BPDB, Bhutan-DGPC, Pakistan-CPPA within NTDC and Sri Lanka-CEB) purchases the electricity from all public and private generation companies and sells it to the distribution companies.

In the Indian electricity sector, the Multi-Year Tariff framework has been mandated as per the Electricity Act. There are three main pricing mechanisms in India's power market such as long-term contract, short-term contract and spot market. State generation utilities sell electricity to distribution companies based on long-term contracts at the prices decided by SERCs or PPAs. The short-term bilateral contracts are mainly used by traders for inter-state or inter-regional power purchase through open access. With regard to the role of Central Regulator and State Regulator of India, the CERC regulates tariffs of generating companies owned or controlled by the central government as well as IPPs that supply more than one state, and inter-state transmission tariffs. The SERCs determines the wholesale, bulk and retail tariff for electricity and the tariff for intra-state transmission facilities within its respective state.

The generation tariff determination is linked with achievement of some operational norms in case of all selected Member States. The government of Bhutan has introduced a unique concept of "Royalty Energy" at their generation tariff determination. According to this concept, Royalty Energy (a portion of energy generated by a licensee) is to be sold by a generation licensee at discount price, called Royalty Price, to implement transfer of subsidy from generation licensee to customers.

Table 18: Key Features of Electricity in Selected Member States

	Bangladesh	***Bhutan***	***India***	***Pakistan***	***Sri Lanka***
Access to Electricity[40] (% of population)	46.5	73.0	75.0	67.4	76.6
Per Capita Electricity[41] Consumption (kWh)	259		684	449	490
Regulator	BERC 2003	BEA 2010	CERC-central SERCs-states	NEPRA 1997	PUCSL 2003
Tariff Setting Objectives	Mixed objectives including cost recovery & social concern; aiming to reach efficient tariff				
Pricing Methodology	Cost-plus				
Lifline Tariff Policy	Yes	Yes	Yes	Yes	Yes
Lifeline amount (kW/month)	75	100	30	50	30
Unbundling of Utilities	Yes	Yes Partially	Yes	Yes	No
Private Sector Participation	Yes, Generation Sector	Encouraged specially in Hydropower generation	Yes	Yes	Yes, Generation Sector
Number of Consumer Classes For Tariff Purposes	6	3	18	10	5

The distribution companies procure electricity from the Single Buyer (that purchases electricity from all generation companies), under a bulk supply tariff, and sell to the end users by adding its operating expenses. For the case of India, Sri Lanka and two companies of Pakistan, the distribution tariff is calculated based on multi-year tariff principles.

Electricity pricing varies from country to country. There are many reasons that account for electricity price differences. The level of electricity price depends on industry structure, ownership structure, fuel mix in power generation and government's policy objectives like economic efficiency and other social policy obligation. Many countries have cross-subsidies among customer categories: lower for households, mainly rural, and agriculture, and higher for other customer categories. In an attempt to deal with the social consequences, Member States have implemented lifeline-tariff policy. Lifeline tariff level and lifeline amount (kWh/month) varies greatly among the Member States. Rural domestic customers

[40] *Year 2010 and data source: World Bank-World Development Indicators 2013.*
[41] *Year 2011 and data source: World Bank-World Development Indicators 2013.*

of Bhutan even enjoy 100 units free electricity per month. Recognizing the importance of demand side management, Member States have implemented some sophisticated tariff structures such as Time of Use tariff, seasonal tariff and capacity charge, reactive energy and power factor adjustment charge. Time of Use tariff is considered as a tool for not only promoting energy efficiency but also for ensuring cost-reflectivity of generation charges. The generation costs vary depending on the electricity demand and the power plants and fuels used to meet the demand. Time of Use tariffs is applied to large commercial and industrial customers in most of the Member States and it is also applicable for large domestic customer in Pakistan. Capacity charges for selected customers are widely used in the Member States. Seasonal tariff (for seasonal consumers like ice factory, cold storage), reactive energy and power factor adjustment charges are used in India.

The current end-user tariff policy in Member States is to have uniform tariffs (i.e. same tariff is maintained for a given customer category) across the country/state (in case of India). However, the retail supply tariff differentiates between rural and urban customers in Bangladesh (domestic, irrigation & non-residential lighting sector), Bhutan (domestic sector) and India (domestic sector). In the Member States, electricity supply tariffs are also differentiated by voltage level as different customer off-take voltages. Lower voltage customers require more infrastructure than the higher voltage customers so the tariffs are differentiated on the basis of voltage levels. Bangladesh has a special tariff setting structure, charged at higher rates, for labor-intensive and export-oriented industries for getting uninterrupted, reliable and quality supply.

For domestic consumers, an incremental block tariff structure has been adopted by the Member States, where a unit price increases in the amount of electricity use. The reasons for the incremental blocks tariff structure are to protect life-line users and to enable cross-subsidization between high volume and low volume consumers.

Appendices

Appendix A: Consumer Electricity Tariff Structure, Bangladesh

For Urban Consumers:

Customer Type, Category and Time of Use, if applicable	Energy Charge (Taka/ Kwh)	Service Charge (Taka/Month)	Demand Charge (Taka/KW/ Month)	Other Charges	
				Minimum Charge	VAT
Domestic (Class-A)					
(a) 1st Stage : 00-75 kWh	3.61	For 1 Phase : 10.00 For 3 Phase: 30.00	15.00	Tk. 100.00/ Connection	5%
(b) 2nd Stage: 76-200 kWh	4.34				
(c) 3rd stage: 201-300 kWh	4.48				
(d) 4th stage: 301-400 kWh	7.09				
(e) 5th stage: 401-600 kWh	7.40				
(f) 6th stage: More than 600 kWh	9.38				
Industrial					
Category 1 (Class-C, Small Industry,0.40 KV)					
Flat :	6.95	For 1 & 3 Phase: 70.00	For 1 Phase : 00.00 For 3 Phase: 40.00*	0	5%
Off-peak time (23:00-17:00)	5.96				
Peak time (17:00-23:00)	8.47				
Category 2 (Class-F, Medium voltage general use, 11 KV)					
Flat :	6.81	400.00	45.00 *	Tk. 80.00/Kw (or Tk. 8000 Which is higher)	5%
Off-peak time (23:00-17:00)	5.96				
Peak time (17:00-23:00)	9.33				
Category 3 (Class-H, High voltage general use, 33 KV)					
Flat :	6.48	450.00	40.00 (on Max. Demand)	Tk. 80.00/Kw (or Tk. 8000 Which is higher)	5%
Off-peak time (23:00-17:00)	5.87				
Peak time (17:00-23:00)	9.14				
Agriculture (Class-B)					
Flat: Irrigation	3.67	For 1 & 3 Phase: 30.00	For 1 Phase : 00.00 For 3 Phase: 40.00 (above 40KW)	For season: Tk. 125.00/HP For off season: Tk.10.00/HP	5%
Commercial (Class-E)					
Flat :	9.00	For 1 Phase : 10.00 For 3 Phase: 30.00	For 1 & 3 Phase: 25.00	Tk. 125.00/Kw	5%
Off-peak time (23:00-17:00)	7.22				
Peak time (17:00-23:00)	11.85				
Charitable Institutions (C.I) Class-D					
Flat: C.I	4.49	For 1 Phase : 10.00 For 3 Phase: 30.00	For 1 & 3 Phase: 20.00	Tk. 125.00/kw	5%
Road Light (Class-J)					
Flat: Road Light	6.48	For 1 & 3 Phase: 210.00	For 1 & 3 Phase: 40.00	0	5%

Note:

* For General Power (400 Volt) and Large Power (11KV) demand charge will be on maximum demand or 70% of the contracted load whichever is higher.

For Rural Consumers:

Customer Type, Category and Time of Use, if applicable	Energy Charge (Taka/ Kwh)	Service Charge (Taka/Month)	Demand Charge (Taka/KW/ Month)	Other Charges	
				Minimum Charge	VAT
Domestic (Class-A)					
(a) 1st Stage : 00-75 kWh	3.33	For 1 Phase : 10.00 For 3 Phase: 30.00	15.00	Tk. 100.00/ Connection	5%
(b) 2nd Stage: 76-200 kWh	4.73				
(c) 3rd stage: 201-300 kWh	4.83				
(d) 4th stage: 301-400 kWh	4.93				
(e) 5th stage: 401-600 kWh	7.97				
(f) 6th stage: More than 600 kWh	9.38				
Industrial					
Category 1 (Class-C, Small Industry, 0.40 KV)					
Flat :	6.95	For 1 & 3 Phase: 70.00	For 1 Phase : 00.00 For 3 Phase: 40.00 (above 40KW)	0	5%
Off-peak time (23:00-17:00)	5.96				
Peak time (17:00-23:00)	8.47				
Category 2 (Class-F, Medium voltage general use, 11 KV)					
Flat :	6.81	400.00	45.00 (on Max. Demand)	Tk. 80.00/Kw (or Tk. 8000 Which is higher)	5%
Off-peak time (23:00-17:00)	5.96				
Peak time (17:00-23:00)	9.33				
Category 3 (Class-H, High voltage general use, 33 KV)					
Flat :	6.48	450.00	40.00 (on Max. Demand)	Tk. 80.00/Kw (or Tk. 8000 Which is higher)	5%
Off-peak time (23:00-17:00)	5.87				
Peak time (17:00-23:00)	9.14				
Category 4 (Class-G-2, Extra High voltage general use, 132 KV)					
Flat :	6.16	500.00	40.00 (on Max. Demand)	Tk. 80.00/Kw (or Tk. 8000 Which is higher)	5%
Off-peak time (23:00-17:00)	5.57				
Peak time (17:00-23:00)	8.67				
Agriculture (Class-B)					
Flat: Irrigation	2.51	For 1 & 3 Phase: 30.00	For 1 Phase : 00.00 For 3 Phase: 40.00 (above 40KW)	Tk. 125.00/HP	5%
Commercial & Office Use (Class-E)					
Flat :	9.00	For 1 Phase : 10.00 For 3 Phase: 30.00	For 1 & 3 Phase: 25.00	Tk. 125.00/kw	5%
Off-peak time (23:00-17:00)	7.22				
Peak time (17:00-23:00)	11.85				
Non Residential Light & Electricity (Class-D)					
Flat: Non-Residential light	4.53	For 1 Phase : 10.00 For 3 Phase: 30.00	For 1 & 3 Phase: 20.00	Tk. 125.00/kw	5%
Road Light & Water Pump (Class-J)					
Flat: Road Light & Water pump	6.48	For 1 & 3 Phase: 210.00	For 1 & 3 Phase: 40.00	0	5%

Appendix B: **Distribution Tariff Description, Bangladesh**

Category - A : Residential Light & Power

Applicable to the electricity service through a single watt hour meter for lighting and appliances used in a dwelling place including related grounds and buildings, having sanctioned load up to 50 KW.

Category - B : Agricultural Pumping

Applicable to the electricity service through a single watt hour meter for irrigation and drainage of the land for the purpose of cultivation, having sanctioned load up to 50 KW.

Category - C : Small Industrial

Category-C is applicable to the electricity service through a single watt hour meter for small industry, where articles or substances are produced, adopted, manufactured, altered, repaired, ornamented, finished, packaged or treated from raw materials with a view to their use, sale, transport, delivery and disposal having a sanctioned load up to 50 KW.

Category - D : Non-Residential Light & Power

Applicable to the electricity service through a single watt hour meter for hospitals, educational institutions, religious & charitable establishments and all classes of consumers other than those specified under category A, B, C, E & J having sanctioned load up to 50 KW.

Category - E : LT Commercial

Applicable to the electricity service through a single watt hour meter for offices, trading and commercial enterprises such as shops, businesses, hotels & cinema halls, having sanctioned load up to 50 KW.

Rate : Category - F : Medium Voltage General Purpose (11 KV)

Applicable to the electricity service through energy and demand meters for all classes consumers having sanctioned load up to 5 MW, where the consumer provides his own sub-station, including transformer, high tension control, protection and power factor correction equipment.

Category - G-1 : Extra High Voltage Desa (132 KV)

Applicable to the electricity service through energy and demand meter for Dhaka Electric

Supply Authority (DESA) receiving power at 132 KV.

Category - G-2 : Extra High Voltage General (132 KV)

Applicable to the electricity service through energy and demand meter for all classes of consumer receiving power at 132 KV having sanctioned load above 15 MW upto150 MW, where the consumer provides his own sub-station including transformer, high tension control, protective and power factor correction equipment.

Category - H : High Voltage General Purpose (33 KV)

Applicable to the electricity service through energy and demand meter for all classes of consumers other than REB/PBS receiving power at 33 KV, having contracted load up to 15 MW other than REB/PBS where the consumer provides his own sub-station, including transformer and high tension control, protective and power factor correction equipment.

In absence of maximum demand meter the maximum demand of the consumers categories G2 & H may be calculated as follows :

100% for the first 75 KW of Connected Load
85% for the next 75 KW of Connected Load
75% for the next 75 KW of Connected Load
65% for the next 75 KW of Connected Load
60% for the rest

Category - I : High Voltage Bulk Supply For Rural Electrification Of Board/ Palli Biddyut Samiti

Applicable to the electricity service through energy and demand meter for REB/PBS receiving power at 33 KV, having contracted load up to 15 MW, where the consumer provides his own transformer, high tension control, protective and power factor correction equipment.

Category - J : Street Light And Water Pumps.

Applicable to the electricity service through a single watt-hour meter for Municipality, WASA and Public Health for the purpose of street lighting and drinking water pumping stations having sanctioned load up to 50 KW.

Source: BERC, BPDB.

Appendix C: Electricity Generation Cost in Bangladesh

Particulars	2011-12		2010-11		(Increase/ Decrease)
	Amount in crore Tk.	Cost (Tk/kWh)	Amount in crore Tk.	Cost (Tk/kWh)	
Total	**17,837.92**	**5.36**	**11,652.49**	**3.95**	**36%**
i. BPDB's Generation	3,754.29	3.67	3,282.39	3.19	15%
ii. Purchase from IPP	3,470.50	3.66	3,213.50	3.42	7%
iii. Purchase from Rental	8,833.83	10.18	4,364.29	8.05	26%
iv. Purchase from Public Plant	983.56	2.02	792.31	1.80	12%
v. Interest on budgetary support	283.39	0.09	116.14	0.04	125%
vi. Provision for Maintenance and Development fund	512.35	0.15	146.68	0.05	200%
Energy Sales	11,185.20		7,730.39		45%

Source: BPDB Annual Report 2011-2012.

Appendix D: Consumer Electricity Tariff Structure, Bhutan

Tariff structure		1st October 2013- 30th June 2014	1st July 2014 - 30th June 2015	1st July 2015 -30th June 2016
Low Voltage				
LV Block I (rural domestic) (0-100 kWh)	Nu./kWh	0	0	0
LV Block I (others) (0-100 kWh)	Nu./kWh	0.98	1.12	1.28
LV Block II (all) (>100-300 kWh)	Nu./kWh	1.86	2.13	2.45
LV Block III (all) (> 300 kWh)	Nu./kWh	2.46	2.82	3.23
LV Bulk	Nu./kWh	2.56	3.07	3.68
Medium Voltage				
Energy Charge	Nu/kWh	1.98	2.19	2.43
Demand Charge	Nu/kW/month	155	195	235
High Voltage				
Energy Charge	Nu/kWh	1.67	1.81	1.96
Demand Charge	Nu/kW/month	130	155	180
Wheeling	Nu/kWh	0.114	0.114	0.114

Source: BPC.

Appendix E: Electricity Tariffs in Sri Lanka

Customer Type: Domestic

Customer Category D-1

This rate applies to supply of electricity used for domestic purposes in private residences. The tariff will be charged on Incremental Block Tariff basis and Fuel Adjustment Charge (FAC) will be charged on basis that respective FAC percentage will be applicable for the entire monetary value of the unit charge.

Table 22- Tariff Applicable for Domestic Customers

A "30 day period" consumption is between 0-60 kWh:

Consumption per month (kWh)	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Fuel Adjustment Charge (% of Energy Charge)
0-30	3.00	30.00	25%
31-60	4.70	60.00	35%

A "30[1] day period" consumption is above 60 kWh:

Consumption per month (kWh)	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Fuel Adjustment Charge (% of Energy Charge)
0-60	10.00		
61-90	12.00	90.00	10%
91-120	26.50	315.00	40%
121- 180	30.50	315.00	40%
>180	42.00	420.00	40%

Customer Type: Religious and Charitable

Customer Category R-1

The tariff will be charged on Incremental Block Tariff basis

This rate shall apply to supplies of electricity to,

a. places of public religious worship including private residences of priests where such residences are associated with or are within the place of public religious worship,

b. Homes for aged, orphanages and homes for the handicapped, which are specifically certified by the Director of Social Services as charitable institutions, and the installation should not include any building used for commercial purposes.

Tariff and Fuel Adjustment Charge effective from 01st Jan. 2011 to date

Table 23- Tariff Applicable for Religious Customers

Consumption[2] per month (kWh)	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)
0-30	1.90	30
31-90	2.80	60
91-120	6.75	180
121-180	7.50	180
>180	9.40	240

Customer Type: Industrial

Supply of electricity used wholly or mainly for motive power or for electro-chemical process in factories, workshops, foundries, oil mills, spinning and weaving mills, water supply and irrigation pumping stations, port and dock installations and other similar industrial installations.

Customer Category I-1

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand is less than or equal to 42 kVA.

Table 24- Tariff Applicable for Industrial-1 Customers

Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge(% of Energy Charge)
12.50	600	-	15%

Customer Category I-2

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand exceeds 42 kVA.

Table 25- Tariff Applicable for Industrial-2 Customers

Time Intervals	Energy Charge (LKR/kWh)	Fixed Charge(LKR/month)	Maximum Demand Charge per month(LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
Day (5.30-18.30)	11.30	3,000	1,100	15%
Peak (18.30-22.30)	21.00			
Off-peak (22.30-05.30)	7.00			

Customer Category I-3

This rate shall apply to supplies at each individual point of supply delivered and metered at 11,000 Volt nominal and above.

Table 26- Tariff Applicable for Industrial-3 Customers

Time Intervals	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month	Fuel Adjustment Charge (% of Energy Charge)
Day (5.30-18.30)	10.50	3,000	1,000	15%
Peak (18.30-22.30)	24.00			
Off-peak (22.30-05.30)	6.00			

Customer Type: Hotel

Supply of electricity used for hotels approved by the Sri Lanka Tourism Development Authority.

Customer Category H-1

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand is less than or equal to 42 kVA.

Table 27- Tariff Applicable for Hotel-1 Customers

Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
22.00	600	-	15%

Customer Category H-2

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand exceeds 42kVA.

Table 28- Tariff Applicable for Hotel-2 Customers

Time Intervals	Energy Charge (LKR/kWh)	Fixed Charge(LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
Day (5.30-18.30)	15.00	3,000	1,100	15%
Peak (18.30-22.30)	24.00			
Off-peak (22.30-05.30)	10.00			

Customer Category H-3

This rate shall apply to supplies at each individual point of supply delivered and metered at 11,000 Volt nominal and above.

Table 29- Tariff Applicable for Hotel-3 Customers

Time Intervals	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
Day (5.30-18.30)	14.00	3,000	1000	15%
Peak (18.30-22.30)	23.00			
Off-peak (22.30-05.30)	9.00			

Customer Type: General

Supply of electricity to be used in shops, offices, banks, warehouses, public buildings, hospitals, educational establishments, places of entertainment and other premises not covered under any other tariffs.

Customer Category G-1

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand is less than or equal to 42 kVA.

Table 30- Tariff Applicable for General-1 Customers

Consumption per month (kWh)	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
<211	19.50	240	-	25%
>210	21.50	240		25%

Customer Category G-2

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand exceeds 42 kVA.

Table 31- Tariff Applicable for General-2 Customers

Time Intervals	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
Day (5.30-18.30)	20.50	3,000	1,100	25%
Peak (18.30-22.30)	25.00			
Off-peak (22.30-05.30)	14.50			

Customer Category G-3

This rate shall apply to supplies at each individual point of supply delivered and metered at 11,000 Volt nominal and above.

Table 32- Tariff Applicable for General-3 Customers

Time Intervals	Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
Day (5.30-18.30)	19.50	3,000	1,000	25%
Peak (18.30-22.30)	24.00			
Off-peak (22.30-05.30)	13.50			

Government Category

Supply of electricity to be used in schools, hospitals, vocational training institutions, and universities, which are fully owned by the Government and funded through the national budget and provide their services free of charge to the general public. These customers shall be of categories GP-1, GP-2 or GP-3. Existing and new customers of the type described above may make an application in writing to

the relevant distribution licensee to obtain the government Category. Fuel Adjustment Charge (FAC) shall not be applied for Government owned hospitals and schools.

Customer Category GV-1

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand is less than or equal to 42 kVA.

Table 33- Tariff Applicable for Government-1 Customers

Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
14.65	.600	-	0 or 25%

Customer Category GV-2

This rate shall apply to supplies at each individual point of supply delivered and metered at 400/230 Volt nominal and where the contract demand exceeds 42 kVA.

Table 34- Tariff Applicable for Government-2 Customers

Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
14.55	3,000	1,100	0 or 25%

Customer Category GV-3

This rate shall apply to supplies at each individual point of supply delivered and metered at 11,000 Volt nominal and above.

Table 35- Tariff Applicable for Government-3 Customers

Energy Charge (LKR/kWh)	Fixed Charge (LKR/month)	Maximum Demand Charge per month (LKR/kVA)	Fuel Adjustment Charge (% of Energy Charge)
14.35	3,000	1,000	0 or 25%

Street Lighting

There shall be two types of street lighting customers, public and private:

(a) Street lighting for public use, where the street lights are fixed along public roads, and where the road belongs to or is maintained by a Local Authority or a Provincial Authority or the Road Development Authority, and where the road users do not pay a fee for the use of such roadways and have unhindered access

(b) Street lighting for private use along roadways belonging to any individual or institution other than the Authorities listed in (a) above. Roadways in which ownership is not specifically defined and any other premises other than a roadway belonging to the authorities listed in (a) including areas designated for recreation (such as parks including roads leading to such parks) or other services (such as offices and depots, and roads leading to such offices and depots), shall be considered as private.

Street lighting for public use shall continue to be metered, invoiced at the rate of Rs. 17.00 kWh, and approved by the relevant Local, Provincial or Road authority.

Source: PUCSL.

Appendix F: Electricity Generation Cost in Sri Lanka

Plant	Energy Dispatched		Total Cost to CEB (Mn.LKR)		Avarage Unit Cost (Rs/kWh)	
	2011	2012 (Jan-Aug)	2011	2012 (Jan-Aug)	2011	2012 (Jan-Aug)
Mahaweli Complex	1914.63	709.985	4326.41	3,814.800	2.26	5.37
Laxapana Complex	1341.323	463.921	2477.53	1,621.200	1.85	3.49
CEB Other Hydro	605.863	272.629	1885.18	1,283.200	3.11	4.71
Sapugaskanda 1	384.241	271.684	4,449.290	4,359.215	11.58	16.05
Sapugaskanda 2	452.989	361.084	4,723.229	5,203.155	10.43	14.41
KPS Small GTs	69.317	82.555	3,510.509	4,013.989	50.64	48.62
KPS GT 7	205.248	120.299	6,454.962	3,528.842	31.45	29.33
KPS CCY	209.677	685.026	7,876.692	17,184.508	37.57	25.09
Puttalam Coal	869.927	967.692	6,226.833	7,999.099	7.16	8.27
Chunnakam	6.119		299.896		49.01	
Lakdhanavi	104.433	74.917	1,491.571	1,449.934	14.28	19.35
Asia Power	290.391	248.714	4,855.487	5,392.192	16.72	21.68
AES Kelanitissa	511.819	550.169	13,992.514	15,965.287	27.34	29.02
Colombo Power	432.610	339.838	5,464.358	6,153.714	12.63	18.11
ACE Matara	134.658	42.716	1,900.557	737.407	14.11	17.26
ACE Horana	145.141	133.409	2,023.089	2,508.088	13.94	18.80
Heladhanavi	649.460	504.880	7,665.975	8,529.802	11.80	16.89
ACE Embilipitiya	385.433	443.776	5,877.662	8,023.401	15.25	18.08
West Coast	1,005.572	1,082.701	22,124.380	25,063.366	22.00	23.15
Aggreko	66.456	38.414	2,067.675	1,494.992	31.11	38.92
Nothern Power	77.718	67.209	1,362.039	1,542.473	17.53	22.95
NCRE	663.333	378.261	8,189.559	5,208.690	12.35	13.77
All Hydro	**3,861.816**	**1,446.535**	**8,689.120**	**6,719.200**	**2.25**	**4.65**
All CEB Thermal	**2,197.518**	**2,488.340**	**33,541.410**	**42,288.809**	**15.26**	**16.99**
ALL IPP Thermal	**3,803.690**	**3,526.743**	**68,825.307**	**76,860.655**	**18.09**	**21.79**
All Plants	**10,526.357**	**7,839.879**	**119,245.396**	**131,077.354**	**11.33**	**16.72**

Source: PUCSL.

Appendix G: Statement of Government of Pakistan Notified Tariff

	w.e.f. 01-07-2010		w.e.f. 01-09-2010		w.e.f. 01-10-2010		w.e.f. 01-11-2010		w.e.f. 15-03-2011		w.e.f. 06-05-2011		w.e.f. 16-05-2012	
	Fixed Charge (Rs./ kW/ Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/ Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/ Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)
RESIDENTIAL														
For Sanctioned Load less than 5 kW														
Up to 50 Units		1.79		1.79		1.83		1.87		1.87		1.87		2.00
For consumption exceeding 50 Units														
01-100 Units		4.20		4.20		4.28		4.36		4.45		4.54		5.79
101-300 Units		6.34		6.34		6.47		6.60		6.73		6.86		8.11
301-700 Units		10.24		10.24		10.44		10.65		10.65		10.65		12.33
Above 700 Units		12.77		12.77		13.03		13.29		13.29		13.29		15.07
For Sanctioned Load 5 kW & above														
Time of Use (TOU) - Peak		11.77		11.77		12.01		12.25		12.25		12.25		13.99
Time of Use (TOU) - Off-Peak		7.18		6.70		6.70		6.70		6.70		6.70		8.22
COMMERCIAL														
For Sanctioned Load less than 5 kW		12.53		12.53		12.78		13.00		13.00		13.00		14.77
For Sanctioned Load 5 kW & above														
Regular	339	7.82	339	7.82	346	7.98	353	8.14	360	8.14	367	8.14	400	9.72
Time of Use (TOU) - Peak		11.05		11.05		11.27		11.49		11.49		11.49		13.20
Time of Use (TOU) - Off-Peak	339	6.74	339	6.50	346	6.50	353	6.50	360	6.50	367	6.50	400	8.01
INDUSTRIAL														
B1 upto 25 kW(at 400/230 Volts)		9.00		8.90		8.90		8.90		8.90		8.90		10.51
B2 5-500 kW (at 400 Volts)	339	7.29	339	7.29	346	7.44	353	7.59	360	7.59	367	7.59	400	9.14
B1 - TOU (Peak)										12.25		12.25		13.99
B1 - TOU (Off-peak)										6.70		6.70		8.22
B2 - TOU (Peak)		11.05		11.05		11.27		10.99		11.08		11.08		12.77
B2 - TOU (Off-peak)	339	6.74	339	6.50	346	6.50	353	6.50	360	6.50	367	6.50	400	8.01
B3 - TOU (Peak) (upto 5000 kW at 11 kV, 33 kV)		10.65		10.65		10.86		11.08		10.99		10.99		12.68
B3 - TOU (Off-peak)	328	6.12	328	6.12	335	6.24	342	6.25	349	6.25	356	6.25	380	7.75
B4 - TOU (Peak) (at 66 kV, 132 kV & above)		10.27		10.27		10.48		10.69		10.69		10.69		12.37
B4 - TOU (Off-peak)	317	5.74	317	5.74	323	5.85	329	5.97	336	5.97	343	5.97	360	7.46

Contd....

	w.e.f. 01-07-2010		w.e.f. 01-09-2010		w.e.f. 01-10-2010		w.e.f. 01-11-2010		w.e.f. 15-03-2011		w.e.f. 06-05-2011		w.e.f. 16-05-2012	
	Fixed Charge (Rs./ kW/ Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/ Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/ Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)	Fixed Charge (Rs./ kW/Month)	Variable Charge (Rs./kWh)
BULK SUPPLY														
C1(a) Supply at 400 Volts- less than 5 kW		9.53		9.53		9.72		9.90		9.90		9.90		11.55
C1(b) Supply at 400 Volts- 5 kW & above	339	8.79	339	8.75	346	8.75	353	8.75	360	8.75	367	8.75	400	10.35
Time of Use (TOU) - Peak		10.87		10.87		11.09		11.31		11.31		11.31		13.01
Time of Use (TOU) - Off-Peak	339	6.64	339	6.50	346	6.50	353	6.50	360	6.50	367	6.50	400	8.01
C2 Supply at 11 kV	328	8.33	328	8.33	335	8.50	342	8.65	349	8.65	356	8.65	380	10.25
Time of Use (TOU) - Peak		10.49		10.49		10.70		10.91		10.91		10.91		12.60
Time of Use (TOU) - Off-Peak	328	6.03	328	6.03	335	6.15	342	6.25	349	6.25	356	6.25	380	7.75
C3 Supply above 11 kV	317	8.18	317	8.18	323	8.34	329	8.51	336	8.51	343	8.51	360	10.10
Time of Use (TOU) - Peak		10.10		10.10		10.30		10.51		10.51		10.51		12.18
Time of Use (TOU) - Off-Peak	317	5.65	317	5.65	323	5.76	329	5.87	336	5.87	343	5.87	360	7.35
AGRICULTURAL														
SCARP		8.14		8.14		8.3		8.47		8.47		8.47		10.00
Agricultural Tube-wells (Punjab and Sindh)	97	5.11	97	5.11	99	5.21	101	5.31	103	5.31	105	5.31	120	6.77
Agricultural Tube-wells (KPK and Balochistan)	97	5.11	97	5.11	99	5.21	101	5.31	103	5.31	105	5.31	120	6.77
Time of Use (TOU) - Peak		9.72		9.72		9.91		10.11		10.11		10.11		13.00
Time of Use (TOU) - Off-Peak	200	4.37	200	4.37	200	4.46	200	4.55	200	4.55	200	4.55	200	8.00
PUBLIC LIGHTING		12.29		12.00		12.00		12.00		12.00		12.00		13.73
RESIDENTIAL COLONIES ATT. TO INDUS,		11.00		11.00		11.00		11.22		11.22		11.22		12.92
Railway Traction		9.58		9.58		9.77		9.96		9.96		9.96		11.00
AJ&K	317	4.05	317	4.05	317	4.13	323	4.21	323	4.21	343	4.21	360	5.63
Time of Use (TOU) - Peak		11.14		11.14		11.36		11.59		11.59		11.59		13.30
Time of Use (TOU) - Off-Peak	317	6.16	317	6.16	317	6.28	323	6.41	323	6.41	343	6.41	360	7.92
RAWAT		8.41		8.41		8.58		8.75		8.75		8.75		11.50

Source: NEPRA.

Appendix H: Comparison of Propose NEPRA Tariff of Pakistan (2011-12)

DESCRIPTION	Fixed Charges Rs./kW/M	IESCO	GEPCO	LESCO	FESCO	MEPCO	PESCO	HESCO	SEPCO	QESCO
		Variable Charges (Rs./kWh)								
RESIDENTIAL										
Up to 50 Units		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Load up to 5 kW										
01-100 Units		8.70	9.50	9.27	9.60	10.00	11.15	10.00	11.13	10.00
101-300 Units		10.20	13.55	10.50	13.00	14.50	15.50	15.00	15.00	13.20
301-700 Units		14.00	15.50	13.50	15.50	16.40	17.50	17.00	17.00	14.30
Above 700 Units		16.50	16.50	15.50	16.50	18.00	19.50	19.00	19.00	16.50
Load Exceeding 5 kW										
Time of Use (TOU) - Peak		15.50	15.00	15.00	15.00	17.00	19.50	19.00	19.00	16.00
Time of Use (TOU) - Off-Peak		9.10	9.50	9.50	9.50	10.00	11.50	11.00	11.50	9.00
COMMERCIAL										
Load up to 5 kW		16.50	17.50	15.00	17.00	18.50	19.50	16.00	16.00	17.00
Load Exceeding 5 kW										
Regular	400.00	11.00	14.50	14.50	14.50	16.00	17.00	15.00	15.00	15.00
Time of Use (TOU) - Peak		15.00	15.00	15.00	15.00	17.00	19.50	19.00	19.00	16.50
Time of Use (TOU) - Off-Peak	400.00	9.30	9.50	9.50	9.50	10.00	11.50	11.00	11.50	8.00
INDUSTRIAL										
B1		11.70	12.00	11.50	12.00	13.00	15.50	14.00	14.00	11.50
B1 Peak		15.50	15.00	15.00	15.00	17.00	19.50	19.00	19.00	16.00
B1 Off-Peak		9.10	9.50	9.50	9.50	10.00	11.50	11.00	11.50	9.00
B2	400.00	10.30	10.50	10.00	11.00	11.50	14.50	13.00	13.00	10.50
B2 - TOU (Peak)		14.30	15.00	15.00	15.00	16.00	19.50	19.00	19.00	16.60
B2 - TOU (Off-Peak)	400.00	9.00	9.30	9.30	9.30	9.70	11.40	10.50	11.00	8.60
B3 - TOU (Peak)		14.10	14.70	14.70	14.70	15.70	19.50	19.00	19.00	16.50
B3 - TOU (Off-Peak)	380.00	8.90	9.20	9.20	9.20	9.60	11.30	10.25	10.50	8.40
B4 - TOU (Peak)		13.90	14.50	14.50	14.50	15.50	19.50	19.00	19.00	16.40
B4 - TOU (Off-Peak)	360.00	8.80	9.10	9.10	9.10	9.50	11.20	10.00	10.25	8.20
BULK SUPPLY										
C1(a) Supply at 400 Volts-up to 5 kW		12.50	13.00	12.00	13.00	14.00	16.50	14.50	14.50	11.50
C1(b) Supply at 400 Volts-exceeding 5 kW	400.00	11.50	11.50	11.00	11.50	12.50	15.50	13.50	13.50	10.50
Time of Use (TOU) - Peak		14.30	15.00	15.00	15.00	16.00	19.50	19.00	19.00	16.60
Time of Use (TOU) - Off-Peak	400.00	9.00	9.30	9.30	9.30	9.70	11.40	10.50	11.00	8.60

Contd....

DESCRIPTION	Fixed Charges Rs./kW/M	IESCO	GEPCO	LESCO	FESCO	MEPCO	PESCO	HESCO	SEPCO	QESCO
		Variable Charges (Rs./kWh)								
C2 Supply at 11 kV	380.00	11.30	11.40	11.00	11.40	12.40	15.25	13.25	13.25	10.40
Time of Use (TOU) - Peak		14.10	14.70	14.70	14.70	15.70	19.50	19.00	19.00	16.50
Time of Use (TOU) - Off-Peak	380.00	8.90	9.20	9.20	9.20	9.60	11.30	10.25	10.50	8.40
C3 Supply above 11 kV	360.00	11.10	11.30	11.00	11.30	12.30	15.00	13.00	13.00	10.30
Time of Use (TOU) - Peak		13.90	14.50	14.50	14.50	15.50	19.50	19.00	19.00	16.40
Time of Use (TOU) - Off-Peak	360.00	8.80	9.10	9.10	9.10	9.50	11.20	10.00	10.25	8.20
AGRICULTURAL										
SCARP		11.20	11.00	10.00	11.00	12.00	14.30	14.00	14.00	13.00
Agricultural Tube-wells	200.00	8.00	9.50	8.00	9.50	10.00	13.30	10.10	10.50	11.50
Time of Use (TOU) - Peak		13.00	14.50	14.50	14.50	15.50	19.50	19.00	19.00	16.50
Time of Use (TOU) - Off-Peak	200.00	8.00	9.10	9.10	9.10	9.50	11.00	8.00	8.00	8.00
PUBLIC LIGHTING		15.00	15.00	14.50	15.00	15.50	16.40	16.50	16.50	14.00
Resid. Colonies attached to Industries		14.00	14.25	13.50	14.00	15.00	16.40	16.50	16.50	14.00
Railway Traction				12.50		11.00				
Special Contracts – AJ&K	360.00	9.60	13.00				13.50			
Time of Use (TOU) - Peak		15.00	14.50				19.50			
Time of Use (TOU) - Off-Peak	360.00	9.00	9.10				11.00			
Special Contracts - Rawat Lab.		11.50								
Average Rate		10.73	11.83	11.05	11.34	11.95	13.77	13.20	13.65	12.15

Source: NEPRA.

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